COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	)	
LOUISVILLE GAS AND ELECTRIC	)	CASE NO. 2018-00295
COMPANY FOR AN ADJUSTMENT OF ITS	)	
ELECTRIC AND GAS RATES	)	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
THE ATTORNEY GENERAL'S SUPPLEMENTAL DATA REQUESTS
FOR INFORMATION
DATED DECEMBER 13, 2018

FILED: JANUARY 2, 2019

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)

COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

                                              Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.
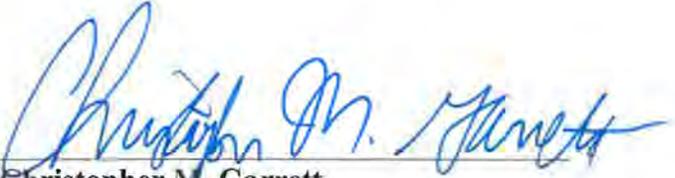
                                              Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

_____
Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

_____
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
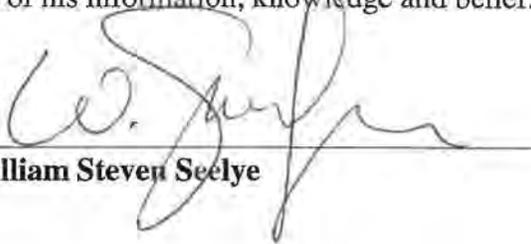**State at Large, Kentucky**
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.
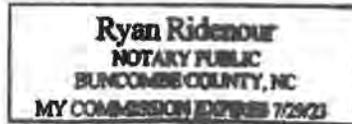
_____
Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

_____
Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.
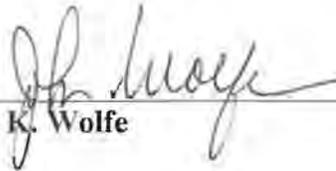
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Elizabeth J. McFarland**, being duly sworn, deposes and says that she is Vice President, Customer Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

_____
Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

_____
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)

COUNTY OF JEFFERSON)

       The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Vice President, Human Resources for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

                                                  Gregory J. Meiman

       Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

                                                  Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

STATE OF NORTH CAROLINA   )

COUNTY OF BUNCOMBE   )

     The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

_____

William Steven Seelye

     Subscribed and sworn to before me, a Notary Public in and before said County and State, this **21** day of **December** 2018.

_____ (SEAL)
Notary Public

My Commission Expires:

7-29-23

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)

COUNTY OF JEFFERSON   )

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

_____
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

_____
Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)

)

COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

_____

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of December 2018.

_____

Notary Public

My Commission Expires:

Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 1

Responding Witness: David S. Sinclair

Q-1.   Reference the Company's response to AG DR 1-137(c):

   a. Explain if interruptible load associated with the Curtailable Service Rider ("CSR") is assumed to be uncurtailed during every hour of the forecasted test year; i.e., hourly class loads include load that could be subject to interruption under the CSR; and,

   b. Explain if the 141 MW of CSR-related load treated as a supply-side resource is treated the same as a generation resource and whether it is available every hour of the year.

A-1.

   a. Forecasted loads are not reduced for potential CSR-related load reductions.

   b. For economic dispatch purposes, CSR curtailments are only available after all of the tariff criteria for utilization have been met. Therefore it is not available every hour of the year. Because the LOLP calculation does not depend on economic dispatch, CSR curtailments are treated the same as generation resources and are effectively available every hour of the year.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 2

Responding Witness: David S. Sinclair

Q-2.   Reference the Company's response to AG DR 1-137(d), Attachment 1, define the various class codes shown in column b of the various tabs.

A-2.   Class Orders in AG DR 1-137(d), Attachment 1, match those in AG DR 1-137(d), Attachments 3 and 4.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 3

Responding Witness: David S. Sinclair

Q-3.   Reference the Company's confidential response to AG DR 1-139(a). Explain if the rows in Table 1 of the confidential attachment represent hypothetical hours, if not, explain what the rows in Table 1 represent.

A-3.   The rows in Table 1 represent possible generation output levels and corresponding probabilities for each generation unit's availability.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 4

Responding Witness: David S. Sinclair

Q-4.   Reference the Company's confidential response to AG DR 1-139(a). Provide the Company's actual amounts utilized within its LOLP analysis for this case associated with Tables 1, 2, and 3 of the confidential attachment.

A-4.   See the attachment in response to AG 1-141(e) for Table 1. See attached for Table 2 and 3.

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
5,905	0.99988349500000	5,414	0.99997956630000	6,321	0.99581641000000	5,695	0.99991881190000
5,846	0.99991563090000	5,332	0.99998733200000	6,282	0.99651226000000	5,655	0.99993342880000
5,844	0.99991703120000	5,319	0.99998843120000	6,247	0.99701050000000	5,621	0.99994573620000
5,835	0.99992067650000	5,296	0.99998988630000	6,186	0.99771641000000	5,609	0.99994958990000
5,827	0.99992372340000	5,271	0.99999136971000	6,110	0.99845331000000	5,583	0.99995685050000
5,793	0.99993737920000	5,255	0.99999222895000	6,100	0.99850587000000	5,581	0.99995636880000
5,787	0.99993944920000	5,255	0.99999227714000	6,100	0.99852726000000	5,545	0.99996375660000
5,760	0.99994832610000	5,167	0.99999536776000	6,084	0.99861959000000	5,528	0.99996859330000
5,692	0.99996477880000	5,165	0.99999547983000	6,079	0.99866695000000	5,491	0.99997366070000
5,674	0.99996858320000	5,156	0.99999565182000	6,059	0.99879234000000	5,489	0.99997499830000
5,650	0.99997236870000	5,155	0.99999586374000	6,027	0.99897338000000	5,477	0.99997630040000
5,630	0.99997544680000	5,148	0.99999594496000	6,017	0.99898855000000	5,465	0.99997767490000
5,615	0.99997753750000	5,118	0.99999656881000	6,010	0.99905693900000	5,391	0.99998596020000
5,588	0.99998127110000	5,094	0.99999716353000	6,007	0.99903305000000	5,371	0.99998695530000
5,578	0.99998213660000	5,053	0.99999784901000	5,998	0.99910326100000	5,367	0.99998799930000
5,553	0.99998442170000	5,043	0.99999795797000	5,991	0.99913047500000	5,364	0.99998764490000
5,515	0.99998760100000	5,042	0.99999787983000	5,989	0.99912160600000	5,350	0.99998851820000
5,503	0.99998852820000	5,035	0.99999804910000	5,980	0.99916951500000	5,334	0.99998952150000
5,488	0.99998945870000	5,032	0.99999812356000	5,968	0.99921492600000	5,323	0.99999076736000
5,481	0.99998989710000	5,012	0.99999880556000	5,961	0.99924619600000	5,286	0.99999260436000
5,469	0.99999055195000	5,003	0.99999839668000	5,953	0.99929430300000	5,283	0.99999233582000
5,457	0.99999127690000	4,988	0.99999858337000	5,944	0.99930514400000	5,254	0.99999367816000
5,438	0.99999224161000	4,972	0.99999865821000	5,925	0.99939226600000	5,226	0.99999490703000
5,438	0.99999228995000	4,969	0.99999911440500	5,916	0.99939298500000	5,203	0.99999562070000
5,428	0.99999292133000	4,968	0.99999869268000	5,914	0.99939569400000	5,186	0.99999586981000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
5,427	0.99999275160000	4,951	0.99999885459000	5,899	0.99944882000000	5,185	0.99999586981000
5,423	0.99999313478000	4,944	0.99999893474000	5,893	0.99946287100000	5,170	0.99999622379000
5,411	0.99999366158000	4,916	0.99999906873800	5,892	0.99948461200000	5,129	0.99999727089000
5,401	0.99999393114000	4,903	0.99999919463200	5,891	0.99946570900000	5,076	0.99999806134000
5,397	0.99999414920000	4,902	0.99999919477400	5,880	0.99951545600000	5,027	0.99999870842000
5,396	0.99999411372000	4,893	0.99999945464900	5,874	0.99951826900000	5,016	0.99999878354000
5,388	0.99999432894000	4,883	0.99999928130600	5,871	0.99952042500000	4,988	0.99999898354000
5,388	0.99999429552000	4,879	0.99999952692400	5,871	0.99953050300000	4,987	0.99999901640800
5,366	0.99999502497000	4,873	0.99999933680900	5,864	0.99955415600000	4,979	0.99999905521100
5,361	0.99999517849000	4,870	0.99999934990900	5,863	0.99955645600000	4,965	0.99999901127500
5,360	0.99999532458000	4,863	0.99999934656400	5,857	0.99955415600000	4,950	0.99999915041200
5,345	0.99999564200000	4,860	0.99999935970400	5,842	0.99958570900000	4,926	0.99999927167900
5,333	0.99999598593000	4,854	0.99999942088400	5,839	0.99959426100000	4,906	0.99999943267400
5,333	0.99999596146000	4,830	0.99999947457900	5,833	0.99959846900000	4,903	0.99999937201700
5,329	0.99999606296000	4,816	0.99999955037300	5,830	0.99960897900000	4,901	0.99999937629600
5,324	0.99999618493000	4,816	0.99999952581000	5,823	0.99964233600000	4,890	0.99999941349900
5,318	0.99999646017000	4,809	0.99999971191300	5,822	0.99964238500000	4,889	0.99999944038600
5,315	0.99999639638000	4,802	0.99999959146100	5,815	0.99964054000000	4,879	0.99999945933600
5,302	0.99999668022000	4,790	0.99999960304100	5,814	0.99965532300000	4,877	0.99999951238700
5,296	0.99999680339000	4,790	0.99999962626300	5,813	0.99964454500000	4,875	0.99999951247400
5,296	0.99999682395000	4,775	0.99999964428000	5,811	0.99966432200000	4,874	0.99999953475800
5,293	0.99999686415000	4,770	0.99999967000900	5,809	0.99964624100000	4,864	0.99999955688800
5,289	0.99999694214000	4,750	0.99999979696900	5,803	0.99966607700000	4,849	0.99999952522300
5,282	0.99999714666000	4,740	0.99999973587700	5,803	0.99967146900000	4,845	0.99999954099900
5,269	0.99999735762000	4,739	0.99999973771800	5,802	0.99966785700000	4,840	0.99999963883600

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
5,259	0.99999752141000	4,738	0.99999973409400	5,802	0.99966073400000	4,837	0.99999969584500
5,246	0.99999757029000	4,726	0.99999975877400	5,793	0.99968176000000	4,830	0.99999961851200
5,230	0.99999790484000	4,722	0.99999975238400	5,783	0.99969835100000	4,825	0.99999959705600
5,224	0.99999798425000	4,717	0.99999984034300	5,783	0.99970152500000	4,819	0.99999968134400
5,223	0.99999799720000	4,713	0.99999972854800	5,782	0.99969187200000	4,818	0.99999968567400
5,222	0.99999800973000	4,708	0.99999973776600	5,777	0.99970944100000	4,814	0.99999969230800
5,221	0.99999801005000	4,704	0.99999978894000	5,777	0.99970640200000	4,792	0.99999973239900
5,219	0.99999804778000	4,686	0.99999981903000	5,768	0.99971587300000	4,782	0.99999975043100
5,215	0.99999809710000	4,684	0.99999987486800	5,768	0.99972174600000	4,776	0.99999973967300
5,212	0.99999813373000	4,680	0.99999978731400	5,763	0.99972793600000	4,774	0.99999973077200
5,201	0.99999829409000	4,678	0.99999978295100	5,758	0.99973908000000	4,773	0.99999976879300
5,187	0.99999834913000	4,669	0.99999989366100	5,751	0.99974730400000	4,757	0.99999978825600
5,180	0.99999847322000	4,661	0.99999989230200	5,744	0.99975650600000	4,753	0.99999980307100
5,178	0.99999850265000	4,657	0.99999985287400	5,742	0.99976029700000	4,724	0.99999983855200
5,177	0.99999852158000	4,655	0.99999985185300	5,741	0.99976783100000	4,723	0.99999983156900
5,162	0.99999865223000	4,648	0.99999990186780	5,741	0.99976059200000	4,720	0.99999983521200
5,155	0.99999877030000	4,639	0.99999986224600	5,728	0.99977151300000	4,720	0.99999980317800
5,148	0.99999877155000	4,636	0.99999986520900	5,725	0.99977868000000	4,717	0.99999984095000
5,141	0.99999883514000	4,636	0.99999987337800	5,722	0.99977991800000	4,714	0.99999984964700
5,137	0.99999885809000	4,634	0.99999987342500	5,722	0.99977287100000	4,710	0.99999988007100
5,134	0.99999888039000	4,622	0.99999985895900	5,713	0.99979370300000	4,709	0.99999985491500
5,128	0.99999895809000	4,596	0.99999993313590	5,711	0.99979578200000	4,689	0.99999987520100
5,124	0.99999894504000	4,592	0.99999990300150	5,710	0.99979710300000	4,685	0.99999986991400
5,123	0.99999890993000	4,584	0.99999991034130	5,707	0.99980662700000	4,681	0.99999989976200
5,120	0.99999901830000	4,583	0.99999991282300	5,707	0.99980662700000	4,661	0.99999988388400

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
5,117	0.99999902484400	4,581	0.99999988885600	5,697	0.99980673500000	4,660	0.99999989203800
5,116	0.99999904343800	4,581	0.99999989638900	5,695	0.99981390500000	4,658	0.99999989933300
5,110	0.99999904439600	4,576	0.99999991295160	5,693	0.99981902300000	4,657	0.99999991564860
5,110	0.99999904439600	4,573	0.99999991421300	5,688	0.99981307900000	4,654	0.99999988564400
5,096	0.99999912858400	4,572	0.99999994469090	5,682	0.99982397400000	4,652	0.99999991802780
5,094	0.99999913998800	4,569	0.99999992177760	5,678	0.99982968100000	4,645	0.99999990301920
5,090	0.99999916778800	4,556	0.99999995049010	5,677	0.99982970600000	4,602	0.99999992405700
5,078	0.99999921626800	4,555	0.99999995049010	5,671	0.99984416800000	4,600	0.99999993142230
5,066	0.99999928628400	4,554	0.99999992935060	5,671	0.99984152000000	4,599	0.99999993477170
5,065	0.99999925703700	4,554	0.99999992679350	5,668	0.99984325100000	4,595	0.99999992469720
5,047	0.99999937202100	4,546	0.99999995330810	5,667	0.99983818700000	4,593	0.99999993296310
5,043	0.99999938874700	4,536	0.99999993804780	5,666	0.99983977900000	4,588	0.99999994936150
5,034	0.99999944339900	4,535	0.99999995696110	5,663	0.99983975600000	4,585	0.99999993679930
5,028	0.99999946901100	4,535	0.99999993763570	5,663	0.99983987100000	4,585	0.99999993767170
5,024	0.99999946238700	4,534	0.99999995759410	5,662	0.99984070100000	4,584	0.99999995049010
5,022	0.99999948675400	4,531	0.99999994027740	5,654	0.99984167800000	4,575	0.99999994345880
5,022	0.99999946595800	4,525	0.99999996120010	5,653	0.99985960400000	4,574	0.99999995498530
5,021	0.99999947318800	4,519	0.99999996289700	5,644	0.99985744700000	4,560	0.99999995028760
5,016	0.99999949063500	4,519	0.99999996317040	5,640	0.99986273800000	4,560	0.99999994451200
5,015	0.99999947995200	4,518	0.99999994650710	5,632	0.99987568100000	4,559	0.99999994211910
5,014	0.99999947318800	4,506	0.99999993489440	5,627	0.99987500600000	4,551	0.99999994245780
5,010	0.99999948719200	4,501	0.99999996685760	5,626	0.99987504200000	4,538	0.99999995523960
5,007	0.99999953924700	4,499	0.99999996805260	5,626	0.99986867800000	4,537	0.99999995523960
5,005	0.99999952710800	4,498	0.99999995281170	5,624	0.99987233300000	4,532	0.99999995989700
5,004	0.99999953033900	4,490	0.99999996923780	5,623	0.99987642500000	4,522	0.99999996900080

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
5,002	0.99999953667100	4,490	0.99999997160860	5,622	0.99987498800000	4,517	0.99999996171410
4,996	0.99999956100600	4,490	0.99999996992400	5,620	0.99987638900000	4,512	0.99999995905840
4,995	0.99999956399500	4,487	0.99999995456860	5,619	0.99987980900000	4,509	0.99999995654470
4,994	0.99999956691500	4,483	0.99999997143600	5,615	0.99987778900000	4,507	0.99999997249600
4,989	0.99999957586900	4,480	0.99999994810020	5,613	0.99988122200000	4,507	0.99999996672630
4,988	0.99999957876500	4,479	0.99999997187030	5,611	0.99987850600000	4,506	0.99999997289830
4,987	0.99999958451200	4,474	0.99999995209860	5,608	0.99988764900000	4,498	0.99999997465290
4,986	0.99999958451200	4,473	0.99999996108610	5,603	0.99988450600000	4,497	0.99999996366350
4,985	0.99999958444100	4,470	0.99999997369840	5,602	0.99989198200000	4,496	0.99999996935340
4,981	0.99999959851100	4,468	0.99999996195210	5,599	0.99989022300000	4,495	0.99999996957750
4,974	0.99999963490800	4,462	0.99999995421690	5,597	0.99989505900000	4,484	0.99999997008650
4,973	0.99999959844100	4,461	0.99999996255570	5,595	0.99989906400000	4,477	0.99999997261190
4,963	0.99999965470000	4,461	0.99999996228340	5,594	0.99989378200000	4,466	0.99999996799210
4,961	0.99999965017100	4,460	0.99999995356670	5,594	0.99989792400000	4,464	0.99999997424060
4,959	0.99999965259900	4,449	0.99999997801330	5,589	0.99989209300000	4,461	0.99999997541790
4,954	0.99999966437300	4,444	0.99999997818980	5,578	0.99989511900000	4,460	0.99999997624430
4,942	0.99999969322900	4,443	0.99999996821970	5,578	0.99990515290000	4,460	0.99999997658650
4,937	0.99999971529500	4,433	0.99999997093500	5,573	0.99990575090000	4,459	0.99999998096820
4,931	0.99999971564500	4,426	0.99999996420450	5,568	0.99990471350000	4,447	0.99999997861480
4,931	0.99999971564500	4,410	0.99999996936560	5,565	0.99990523560000	4,441	0.99999997833070
4,929	0.99999971952500	4,410	0.99999998329790	5,563	0.99991379570000	4,439	0.99999997926550
4,927	0.99999972333400	4,408	0.99999997462210	5,559	0.99991143970000	4,434	0.99999998428630
4,925	0.99999971554600	4,407	0.99999997641820	5,554	0.99991671100000	4,433	0.99999997943910
4,924	0.99999972712700	4,404	0.99999998416910	5,553	0.99991430820000	4,431	0.99999998134140
4,924	0.99999973077000	4,404	0.99999997693450	5,552	0.99991622280000	4,431	0.99999998038640

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,924	0.99999972901500	4,403	0.99999997556150	5,551	0.99991621050000	4,426	0.99999998499280
4,921	0.99999973453800	4,403	0.99999998417220	5,549	0.99991814070000	4,419	0.99999997261190
4,920	0.99999973453800	4,397	0.9999998488210	5,548	0.99991573340000	4,419	0.99999998577990
4,920	0.99999973633600	4,395	0.99999997797600	5,547	0.99991341810000	4,415	0.99999997800160
4,919	0.99999972521700	4,394	0.99999997161250	5,538	0.99991862910000	4,405	0.99999998340190
4,919	0.99999975186700	4,388	0.99999998690330	5,537	0.99992521750000	4,404	0.99999998246720
4,917	0.99999974175200	4,386	0.99999997440150	5,530	0.99992653600000	4,404	0.99999998437070
4,913	0.99999974874000	4,379	0.99999997606840	5,530	0.99992438970000	4,400	0.99999998426860
4,908	0.99999975725400	4,379	0.9999998730720	5,528	0.99992738960000	4,399	0.99999998426550
4,908	0.99999975725400	4,378	0.9999998063100	5,527	0.99993062070000	4,399	0.99999998770830
4,907	0.99999975893900	4,371	0.99999997728780	5,527	0.99992651440000	4,396	0.9999998816460
4,907	0.99999976208200	4,369	0.99999998165020	5,524	0.99992819000000	4,388	0.99999998425640
4,903	0.99999976550500	4,366	0.9999998833960	5,521	0.99992868310000	4,387	0.99999997861480
4,901	0.99999977028300	4,362	0.9999998843510	5,519	0.99993450300000	4,387	0.99999998879250
4,899	0.99999977189600	4,361	0.99999997924090	5,516	0.99993108980000	4,387	0.99999998248080
4,898	0.99999977647400	4,359	0.99999998287250	5,513	0.99993525840000	4,381	0.99999998662500
4,897	0.99999977659100	4,358	0.99999998261860	5,510	0.99993417610000	4,381	0.99999998718570
4,895	0.99999977659100	4,340	0.99999999032491	5,507	0.99993148700000	4,379	0.99999998962010
4,890	0.99999978717700	4,334	0.99999999069746	5,507	0.99993149700000	4,377	0.99999998702830
4,885	0.99999979306200	4,333	0.99999998260850	5,505	0.99993713230000	4,374	0.99999998986720
4,885	0.99999978710200	4,332	0.99999999084447	5,504	0.99993534470000	4,366	0.99999998530810
4,884	0.99999978858000	4,330	0.99999999105560	5,501	0.99994064690000	4,352	0.99999999178880
4,884	0.99999979449900	4,328	0.99999998619100	5,499	0.99993718780000	4,348	0.99999999001387
4,881	0.99999980281200	4,327	0.99999998387610	5,493	0.99993925980000	4,346	0.99999998953550
4,879	0.99999980824600	4,327	0.99999998288250	5,492	0.99994365220000	4,345	0.99999999030401

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,878	0.99999980690600	4,327	0.99999999125971	5,490	0.99994097570000	4,344	0.99999998721120
4,878	0.99999980020100	4,326	0.99999999139079	5,486	0.99994239190000	4,343	0.99999999204599
4,876	0.99999980429300	4,326	0.99999999132906	5,486	0.99994200690000	4,336	0.99999998508010
4,873	0.99999981113900	4,322	0.99999998459920	5,480	0.99994429390000	4,335	0.99999998929270
4,868	0.99999981636600	4,318	0.99999998506500	5,480	0.99994371880000	4,335	0.99999998815740
4,866	0.99999981897600	4,313	0.99999999210859	5,480	0.99994139740000	4,333	0.99999999264759
4,864	0.99999982142700	4,311	0.99999999247006	5,478	0.99994071690000	4,331	0.99999999091693
4,863	0.99999982023600	4,310	0.99999999235381	5,474	0.99994339350000	4,330	0.99999999075883
4,857	0.99999983245200	4,309	0.99999999241297	5,471	0.99994436810000	4,328	0.99999999125798
4,857	0.99999983133900	4,308	0.99999998606420	5,470	0.99995013320000	4,324	0.99999999315044
4,847	0.99999984062900	4,307	0.99999999297347	5,470	0.99994713600000	4,323	0.99999998709110
4,843	0.99999984511900	4,307	0.99999998543010	5,467	0.99994955110000	4,319	0.99999999152315
4,827	0.99999986170000	4,305	0.99999999259110	5,467	0.99995183330000	4,317	0.99999999061554
4,826	0.99999986547800	4,305	0.99999999297638	5,462	0.99995103130000	4,316	0.99999999023244
4,826	0.99999986250000	4,304	0.99999998851390	5,462	0.99994838280000	4,311	0.99999999256946
4,824	0.99999986832200	4,303	0.99999999233476	5,459	0.99995377050000	4,310	0.99999999145026
4,821	0.99999986922800	4,300	0.99999998679270	5,457	0.99995295040000	4,310	0.99999999053329
4,819	0.99999987544800	4,298	0.99999998709110	5,453	0.99994989630000	4,310	0.99999999386165
4,818	0.99999987114400	4,282	0.99999999390688	5,453	0.99995325470000	4,307	0.99999999400198
4,815	0.99999987637700	4,281	0.99999999386165	5,449	0.99995379880000	4,307	0.99999999285482
4,809	0.99999987386200	4,279	0.99999998893060	5,449	0.99995565910000	4,304	0.99999999246425
4,806	0.99999988162200	4,273	0.99999999436638	5,447	0.99995378470000	4,303	0.99999999423571
4,802	0.99999988413100	4,268	0.99999998920660	5,446	0.99995487360000	4,301	0.99999999302384
4,802	0.99999988495400	4,265	0.99999999145698	5,444	0.99995300020000	4,300	0.99999999287451
4,791	0.99999989282900	4,265	0.99999999196572	5,438	0.99995569220000	4,297	0.99999999454008

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,784	0.99999989805100	4,263	0.99999998961570	5,436	0.99995691110000	4,294	0.99999999349876
4,781	0.99999989585300	4,261	0.99999999221345	5,429	0.99996100690000	4,290	0.99999999475495
4,781	0.99999990364380	4,258	0.99999999499330	5,428	0.99995939650000	4,288	0.99999999335689
4,781	0.99999990091850	4,254	0.99999999507288	5,422	0.99996169110000	4,286	0.99999999499532
4,778	0.99999990767340	4,254	0.99999999222443	5,422	0.99996053320000	4,281	0.99999999386165
4,777	0.99999990373150	4,252	0.99999999269156	5,422	0.99996011780000	4,280	0.99999999216395
4,777	0.99999990371420	4,240	0.99999999555951	5,422	0.99996102460000	4,279	0.99999999526739
4,774	0.99999990364380	4,239	0.99999999308876	5,421	0.99996213580000	4,274	0.99999999541426
4,773	0.99999990647700	4,234	0.99999999335689	5,417	0.99996324070000	4,269	0.99999999441332
4,772	0.99999990647700	4,232	0.99999999583356	5,414	0.99996190970000	4,267	0.99999999566520
4,770	0.99999991284270	4,227	0.99999999371017	5,411	0.99996431570000	4,265	0.99999999450016
4,769	0.99999990845180	4,225	0.99999999251423	5,407	0.99996217020000	4,264	0.99999999579984
4,769	0.99999990975310	4,225	0.99999999606197	5,406	0.99996218130000	4,264	0.99999999385820
4,769	0.99999990845180	4,223	0.99999999263337	5,398	0.99996370450000	4,261	0.99999999589891
4,766	0.99999991106220	4,222	0.99999999280560	5,396	0.99996573690000	4,259	0.99999999506744
4,763	0.99999991415650	4,221	0.99999999395473	5,395	0.99996434240000	4,257	0.99999999471145
4,761	0.99999991478770	4,217	0.99999999436098	5,395	0.99996674990000	4,257	0.99999999351069
4,753	0.99999991959270	4,214	0.99999999639596	5,393	0.99996653100000	4,254	0.99999999609208
4,751	0.99999991603490	4,214	0.99999999466223	5,391	0.99996882690000	4,254	0.99999999606197
4,750	0.99999992073640	4,212	0.99999999650742	5,389	0.99996863820000	4,253	0.99999999495795
4,747	0.99999992185460	4,210	0.99999999630155	5,384	0.99996974930000	4,253	0.99999999609366
4,746	0.99999992299880	4,209	0.99999999674877	5,380	0.99996992310000	4,250	0.99999999380921
4,745	0.99999992355130	4,208	0.99999999482785	5,379	0.99997027230000	4,250	0.99999999239923
4,739	0.99999992624230	4,208	0.99999999656451	5,376	0.99996976320000	4,250	0.99999999251423
4,738	0.99999992565530	4,205	0.99999999365223	5,375	0.99996973530000	4,249	0.99999999630515

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,737	0.99999992731360	4,204	0.99999999379790	5,375	0.99996830830000	4,233	0.99999999667326
4,735	0.99999992885910	4,203	0.99999999687603	5,372	0.99997131930000	4,230	0.99999999590056
4,733	0.99999992987930	4,195	0.99999999669542	5,371	0.99997132370000	4,230	0.99999999602298
4,733	0.99999992987930	4,195	0.99999999693055	5,367	0.99997215870000	4,229	0.99999999690361
4,733	0.99999992624230	4,191	0.99999999431488	5,367	0.99997166880000	4,226	0.99999999559042
4,732	0.99999992678650	4,190	0.99999999672404	5,366	0.99996995490000	4,224	0.99999999690613
4,732	0.99999992678650	4,189	0.99999999548516	5,364	0.99997115780000	4,223	0.99999999693055
4,729	0.99999993137620	4,186	0.99999999461813	5,360	0.99997392340000	4,213	0.99999999719114
4,729	0.99999993279850	4,184	0.99999999730003	5,354	0.99997423290000	4,211	0.99999999461813
4,728	0.99999993235980	4,183	0.99999999478489	5,349	0.99997437260000	4,207	0.99999999672438
4,722	0.99999993703720	4,182	0.99999999734456	5,347	0.99997544460000	4,205	0.99999999734732
4,720	0.99999993704870	4,181	0.99999999732317	5,342	0.99997628600000	4,204	0.99999999746966
4,718	0.99999993966130	4,180	0.99999999454314	5,341	0.99997410330000	4,203	0.99999999454207
4,718	0.99999993880420	4,176	0.99999999471145	5,339	0.99997601400000	4,203	0.99999999627556
4,714	0.99999994097570	4,175	0.99999999499070	5,338	0.99997670510000	4,201	0.99999999690110
4,713	0.99999993973960	4,175	0.99999999599352	5,337	0.99997614400000	4,198	0.99999999699911
4,709	0.99999993797630	4,174	0.99999999742921	5,335	0.99997779180000	4,192	0.99999999765583
4,706	0.99999994147260	4,173	0.99999999738958	5,334	0.99997516100000	4,190	0.99999999763816
4,703	0.99999994355230	4,172	0.99999999615031	5,332	0.99997687460000	4,186	0.99999999551713
4,699	0.99999994230290	4,170	0.99999999514861	5,332	0.99997818910000	4,186	0.99999999712334
4,699	0.99999994516310	4,166	0.99999999526032	5,332	0.99997805950000	4,184	0.99999999714606
4,695	0.99999994714670	4,166	0.99999999755297	5,332	0.99997752900000	4,184	0.99999999778847
4,694	0.99999994675970	4,166	0.99999999759178	5,332	0.99997629340000	4,181	0.99999999719375
4,692	0.99999994752610	4,163	0.99999999633292	5,331	0.99997727020000	4,168	0.99999999716892
4,690	0.99999994903650	4,162	0.99999999522881	5,330	0.99997780570000	4,168	0.99999999806834

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,688	0.99999995118790	4,160	0.99999999767548	5,329	0.99997740980000	4,168	0.99999999806834
4,686	0.99999995014980	4,157	0.99999999773375	5,318	0.99997959770000	4,166	0.99999999822561
4,686	0.99999994752610	4,156	0.99999999575971	5,317	0.99997885190000	4,164	0.99999999772903
4,686	0.99999995014980	4,156	0.99999999775257	5,317	0.99997832990000	4,163	0.99999999776689
4,685	0.99999995014980	4,152	0.99999999572980	5,315	0.99997873530000	4,163	0.99999999630233
4,684	0.99999994865320	4,148	0.99999999605447	5,314	0.99998043900000	4,162	0.99999999819332
4,684	0.99999995051340	4,147	0.99999999599268	5,309	0.99997949310000	4,162	0.99999999827527
4,682	0.99999995160420	4,142	0.99999999806714	5,309	0.99997860980000	4,161	0.99999999734598
4,681	0.99999995231980	4,138	0.99999999624305	5,308	0.99998067440000	4,158	0.99999999627479
4,680	0.99999994978600	4,138	0.99999999808407	5,308	0.99997971460000	4,155	0.99999999647594
4,678	0.99999995266250	4,136	0.99999999630310	5,308	0.99997947420000	4,153	0.99999999653430
4,678	0.99999995300780	4,135	0.99999999819223	5,307	0.99997985900000	4,151	0.99999999730138
4,677	0.99999995087840	4,134	0.99999999820755	5,306	0.99997972410000	4,148	0.99999999669611
4,676	0.99999995300780	4,133	0.99999999707458	5,305	0.99998114870000	4,147	0.99999999793066
4,673	0.99999995231980	4,131	0.99999999655826	5,303	0.99998113970000	4,146	0.99999999786139
4,673	0.99999995471460	4,129	0.99999999650498	5,301	0.99998170940000	4,144	0.99999999806621
4,672	0.99999995568330	4,128	0.99999999639377	5,301	0.99998136790000	4,139	0.99999999865976
4,669	0.99999995667720	4,127	0.99999999642305	5,300	0.99998115460000	4,137	0.99999999702413
4,669	0.99999995603870	4,125	0.99999999847507	5,297	0.99998125170000	4,137	0.99999999697617
4,667	0.99999995669360	4,120	0.99999999672201	5,290	0.99998081830000	4,136	0.99999999865072
4,667	0.99999995851690	4,119	0.99999999844533	5,289	0.99998159430000	4,136	0.99999999865072
4,662	0.99999995825540	4,116	0.99999999862273	5,285	0.99998246960000	4,135	0.99999999867499
4,662	0.99999995636310	4,113	0.99999999683113	5,284	0.99998379720000	4,129	0.99999999835622
4,661	0.99999996062030	4,107	0.99999999871764	5,284	0.99998238670000	4,129	0.99999999831597
4,660	0.99999995918010	4,105	0.99999999768869	5,282	0.99998260130000	4,126	0.99999999825503

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,658	0.99999995948130	4,101	0.99999999874938	5,280	0.99998330990000	4,122	0.99999999885393
4,655	0.99999996037690	4,101	0.99999999784103	5,279	0.99998309770000	4,122	0.99999999791075
4,653	0.99999996232760	4,099	0.99999999723571	5,278	0.99998320370000	4,120	0.99999999886574
4,652	0.99999996125510	4,097	0.99999999877663	5,277	0.99998361330000	4,120	0.99999999719375
4,652	0.99999996233500	4,097	0.99999999879333	5,272	0.99998362590000	4,119	0.99999999847824
4,650	0.99999996343030	4,093	0.99999999736637	5,272	0.99998360560000	4,117	0.99999999889875
4,650	0.99999996007720	4,088	0.99999999749242	5,272	0.99998438790000	4,112	0.99999999749296
4,649	0.99999996208230	4,084	0.99999999880563	5,272	0.99998438050000	4,110	0.99999999762851
4,649	0.99999996209630	4,084	0.99999999876735	5,270	0.99998493600000	4,110	0.99999999755247
4,648	0.99999996037690	4,082	0.99999999823032	5,269	0.99998438790000	4,109	0.99999999873598
4,648	0.99999996237000	4,077	0.99999999903457	5,266	0.99998493840000	4,106	0.99999999764805
4,648	0.99999996209630	4,077	0.99999999906494	5,265	0.99998546840000	4,106	0.99999999818953
4,647	0.99999996265110	4,076	0.99999999904217	5,265	0.99998419670000	4,102	0.99999999871906
4,646	0.99999996293210	4,075	0.99999999907279	5,259	0.99998495230000	4,098	0.99999999872409
4,643	0.99999996347890	4,075	0.99999999782187	5,258	0.99998457050000	4,096	0.99999999890477
4,642	0.99999996400850	4,074	0.99999999833303	5,256	0.99998503050000	4,096	0.99999999783994
4,642	0.99999996263730	4,074	0.99999999768918	5,254	0.99998458720000	4,092	0.99999999917507
4,641	0.99999996479270	4,073	0.99999999906577	5,254	0.99998485820000	4,092	0.99999999795061
4,639	0.99999996480590	4,072	0.99999999892696	5,248	0.99998522430000	4,091	0.99999999789451
4,637	0.99999996532270	4,071	0.99999999787532	5,243	0.99998599480000	4,089	0.99999999918886
4,635	0.99999996557600	4,070	0.99999999830429	5,243	0.99998681130000	4,088	0.99999999920835
4,635	0.99999996606720	4,064	0.99999999791208	5,243	0.99998607900000	4,087	0.99999999890763
4,634	0.99999996655670	4,064	0.99999999915688	5,237	0.99998743560000	4,086	0.99999999791295
4,634	0.99999996454330	4,058	0.99999999929239	5,235	0.99998642030000	4,084	0.99999999812978
4,633	0.99999996632560	4,057	0.99999999799985	5,233	0.99998729230000	4,083	0.99999999851671

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,632	0.99999996632560	4,055	0.99999999815973	5,224	0.99998781910000	4,081	0.99999999903940
4,632	0.99999996657550	4,053	0.99999999926580	5,223	0.99998819310000	4,078	0.99999999822987
4,630	0.99999996706740	4,052	0.99999999808651	5,221	0.99998840900000	4,077	0.99999999933139
4,629	0.99999996682410	4,052	0.99999999928048	5,221	0.99998803970000	4,075	0.99999999932628
4,629	0.99999996731100	4,050	0.99999999860933	5,221	0.99998896590000	4,075	0.99999999912263
4,624	0.99999996682410	4,046	0.99999999932056	5,219	0.99998789190000	4,072	0.99999999938420
4,623	0.99999996849640	4,046	0.99999999821244	5,218	0.99998834430000	4,070	0.99999999891606
4,618	0.99999996985440	4,045	0.99999999934236	5,215	0.99998896770000	4,070	0.99999999816342
4,617	0.99999997092660	4,044	0.99999999831812	5,215	0.99998790710000	4,068	0.99999999947157
4,616	0.99999997029930	4,043	0.99999999834734	5,213	0.99998856220000	4,066	0.99999999909968
4,616	0.99999996917200	4,043	0.99999999934263	5,211	0.99998897300000	4,066	0.99999999825503
4,614	0.99999996961830	4,042	0.99999999838661	5,210	0.99998862160000	4,065	0.99999999878705
4,613	0.99999997094300	4,041	0.99999999841292	5,210	0.99998930650000	4,063	0.99999999946093
4,611	0.99999996985440	4,038	0.99999999848378	5,209	0.99998884390000	4,063	0.99999999946093
4,611	0.99999997138060	4,036	0.99999999944604	5,209	0.99998969890000	4,062	0.99999999917532
4,610	0.99999997219130	4,036	0.99999999886131	5,208	0.99998937430000	4,061	0.99999999904174
4,609	0.99999997158860	4,035	0.99999999849687	5,206	0.99998903780000	4,056	0.99999999957286
4,608	0.99999997196280	4,035	0.99999999893714	5,206	0.99998937770000	4,055	0.99999999909968
4,607	0.99999997073390	4,035	0.99999999945347	5,205	0.99999001573000	4,054	0.99999999925108
4,605	0.99999997261550	4,035	0.99999999939638	5,204	0.99998870360000	4,052	0.99999999899794
4,605	0.99999997377480	4,033	0.99999999888478	5,202	0.99998970400000	4,051	0.99999999958944
4,603	0.99999997158860	4,032	0.99999999889397	5,199	0.99998983190000	4,050	0.99999999966198
4,602	0.99999997322150	4,030	0.99999999860628	5,199	0.99998984000000	4,047	0.99999999870801
4,602	0.99999997302320	4,030	0.99999999858424	5,199	0.99998969720000	4,046	0.99999999961995
4,598	0.99999997380980	4,028	0.99999999854814	5,193	0.99999032593000	4,046	0.99999999940653

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,598	0.99999997400820	4,028	0.99999999854855	5,190	0.99998964870000	4,045	0.99999999910527
4,597	0.99999997400820	4,025	0.99999999949933	5,186	0.99998964870000	4,040	0.99999999973716
4,597	0.99999997400820	4,024	0.99999999857493	5,185	0.99999063428000	4,037	0.99999999975669
4,595	0.99999997322150	4,022	0.99999999960696	5,181	0.99999080353000	4,037	0.99999999974235
4,592	0.99999997380980	4,022	0.99999999954450	5,180	0.99999091374000	4,034	0.99999999951454
4,592	0.99999997380980	4,019	0.99999999956865	5,175	0.99999051626000	4,031	0.99999999880661
4,589	0.99999997621550	4,019	0.99999999962280	5,173	0.99999124868000	4,031	0.99999999958663
4,581	0.99999997711060	4,018	0.99999999908257	5,167	0.99999114206000	4,030	1.00000000000000
4,578	0.99999997761180	4,017	0.99999999870066	5,165	0.99999152109000	4,029	0.99999999929712
4,578	0.99999997761600	4,013	0.99999999974186	5,164	0.99999162470000	4,029	0.99999999949446
4,576	0.99999997778380	4,012	0.99999999925173	5,160	0.99999151846000	4,026	0.99999999964325
4,573	0.99999997844360	4,009	0.99999999889154	5,159	0.99999197286000	4,025	0.99999999957021
4,568	0.99999997924670	4,008	0.99999999922333	5,157	0.99999188347000	4,023	0.99999999961295
4,568	0.99999997811560	4,005	0.99999999977474	5,157	0.99999192519000	4,023	0.99999999958944
4,564	0.99999997985980	4,003	0.99999999967168	5,153	0.99999236889000	4,021	1.00000000000000
4,562	0.99999998016350	4,003	0.99999999977486	5,151	0.99999260597000	4,021	0.99999999927766
4,561	0.99999997924670	4,000	0.99999999895558	5,150	0.99999241658000	4,020	0.99999999972939
4,560	0.99999998116060	3,999	0.99999999901821	5,146	0.99999217575000	4,018	1.00000000000000
4,558	0.99999998089610	3,999	0.99999999898311	5,145	0.99999255461000	4,017	1.00000000000000
4,554	0.99999998118610	3,999	0.99999999903918	5,140	0.99999318533000	4,017	0.99999999964599
4,554	0.99999998118610	3,997	1.00000000000000	5,140	0.99999322729000	4,014	0.99999999908281
4,553	0.99999998046540	3,993	0.99999999985347	5,140	0.99999301573000	4,014	1.00000000000000
4,553	0.99999998146360	3,993	1.00000000000000	5,138	0.99999335439000	4,011	1.00000000000000
4,551	0.99999998146720	3,991	0.99999999906323	5,137	0.99999314116000	4,009	0.99999999959464
4,551	0.99999998075460	3,989	0.99999999912926	5,136	0.99999322504000	4,007	0.99999999913053

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,551	0.99999998228240	3,989	1.00000000000000	5,134	0.99999335218000	4,006	0.99999999985273
4,549	0.99999998188310	3,988	1.00000000000000	5,132	0.99999327254000	4,006	0.99999999918225
4,549	0.99999998241000	3,988	0.99999999982211	5,132	0.99999306230000	4,001	0.99999999927602
4,549	0.99999998241690	3,985	1.00000000000000	5,130	0.99999322616000	4,000	1.00000000000000
4,549	0.99999998202030	3,983	1.00000000000000	5,129	0.99999318420000	3,999	0.99999999967168
4,549	0.99999998201680	3,982	1.00000000000000	5,128	0.99999330954000	3,995	1.00000000000000
4,547	0.99999998242030	3,981	1.00000000000000	5,126	0.99999352432000	3,995	1.00000000000000
4,546	0.99999998132970	3,980	1.00000000000000	5,122	0.99999403223000	3,994	1.00000000000000
4,546	0.99999998229270	3,979	0.99999999955328	5,121	0.99999383981000	3,991	0.99999999935914
4,540	0.99999998392340	3,978	1.00000000000000	5,119	0.99999376604000	3,990	1.00000000000000
4,540	0.99999998255680	3,978	1.00000000000000	5,118	0.99999410829000	3,990	0.99999999935313
4,539	0.99999998307480	3,976	0.99999999926731	5,118	0.99999399495000	3,989	0.99999999927766
4,538	0.99999998345220	3,973	1.00000000000000	5,118	0.99999403618000	3,988	0.99999999968469
4,537	0.99999998358000	3,973	1.00000000000000	5,117	0.99999399495000	3,988	0.99999999938276
4,536	0.99999998369930	3,971	1.00000000000000	5,114	0.99999396143000	3,988	1.00000000000000
4,536	0.99999998417590	3,970	1.00000000000000	5,113	0.99999432758000	3,984	1.00000000000000
4,534	0.99999998394850	3,964	1.00000000000000	5,111	0.99999399495000	3,984	0.99999999949137
4,533	0.99999998407040	3,963	0.99999999935313	5,110	0.99999429077000	3,983	0.99999999982228
4,532	0.99999998332810	3,962	0.99999999964890	5,109	0.99999446958000	3,981	0.99999999972363
4,530	0.99999998442630	3,961	1.00000000000000	5,108	0.99999432664000	3,980	0.99999999949867
4,528	0.99999998477190	3,955	1.00000000000000	5,106	0.99999432852000	3,979	1.00000000000000
4,528	0.99999998454420	3,954	1.00000000000000	5,106	0.99999447320000	3,977	0.99999999953473
4,527	0.99999998543310	3,954	0.99999999949195	5,105	0.99999392580000	3,977	1.00000000000000
4,526	0.99999998477480	3,953	1.00000000000000	5,103	0.99999428981000	3,976	1.00000000000000
4,526	0.99999998407040	3,953	0.99999999945360	5,102	0.99999450630000	3,976	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,526	0.99999998453240	3,952	1.00000000000000	5,101	0.99999439756000	3,975	0.99999999949983
4,519	0.99999998566770	3,950	0.99999999950083	5,101	0.99999432758000	3,974	0.99999999947134
4,519	0.99999998489120	3,950	0.99999999950026	5,098	0.99999477655000	3,973	0.99999999950100
4,517	0.99999998578200	3,950	1.00000000000000	5,097	0.99999474198000	3,972	1.00000000000000
4,517	0.99999998599330	3,946	1.00000000000000	5,097	0.99999439756000	3,970	0.99999999955417
4,514	0.99999998545300	3,946	1.00000000000000	5,096	0.99999477910000	3,970	0.99999999953601
4,513	0.99999998620490	3,945	0.99999999962068	5,093	0.99999490944000	3,970	1.00000000000000
4,512	0.99999998640840	3,943	1.00000000000000	5,092	0.99999484662000	3,969	1.00000000000000
4,512	0.99999998641370	3,943	1.00000000000000	5,091	0.99999474711000	3,967	1.00000000000000
4,511	0.99999998651800	3,942	1.00000000000000	5,090	0.99999467767000	3,966	1.00000000000000
4,511	0.99999998629930	3,941	1.00000000000000	5,088	0.99999491356000	3,965	0.99999999965017
4,505	0.99999998702290	3,939	1.00000000000000	5,085	0.99999509741000	3,965	1.00000000000000
4,504	0.99999998651800	3,938	0.99999999964755	5,082	0.99999494183000	3,965	1.00000000000000
4,503	0.99999998722060	3,938	1.00000000000000	5,079	0.99999494016000	3,962	1.00000000000000
4,503	0.99999998787090	3,935	1.00000000000000	5,078	0.99999509741000	3,959	1.00000000000000
4,503	0.99999998720300	3,934	0.99999999964869	5,077	0.99999513354000	3,956	1.00000000000000
4,500	0.99999998751130	3,933	0.99999999972176	5,076	0.99999557270000	3,955	1.00000000000000
4,497	0.99999998779460	3,933	1.00000000000000	5,075	0.99999534414000	3,955	1.00000000000000
4,497	0.99999998788760	3,929	1.00000000000000	5,075	0.99999557345000	3,954	1.00000000000000
4,496	0.99999998788760	3,928	0.99999999974448	5,074	0.99999557420000	3,953	1.00000000000000
4,495	0.99999998807390	3,927	1.00000000000000	5,073	0.99999519282000	3,948	1.00000000000000
4,494	0.99999998816550	3,923	0.99999999982078	5,073	0.99999545943000	3,948	0.99999999977616
4,494	0.99999998807390	3,921	0.99999999982507	5,072	0.99999507196000	3,947	0.99999999967090
4,493	0.99999998778980	3,920	0.99999999981443	5,070	0.99999534794000	3,943	1.00000000000000
4,489	0.99999998852460	3,919	1.00000000000000	5,070	0.99999539972000	3,943	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,481	0.99999998870220	3,919	1.00000000000000	5,066	0.99999531562000	3,942	1.00000000000000
4,480	0.99999998937800	3,919	0.99999999985467	5,064	0.99999552257000	3,942	1.00000000000000
4,480	0.99999998938000	3,916	1.00000000000000	5,064	0.99999557785000	3,941	1.00000000000000
4,475	0.99999998921300	3,916	1.00000000000000	5,063	0.99999554547000	3,939	1.00000000000000
4,474	0.99999998978470	3,914	1.00000000000000	5,061	0.99999560828000	3,936	1.00000000000000
4,473	0.99999999023784	3,914	1.00000000000000	5,059	0.99999554913000	3,934	1.00000000000000
4,470	0.99999999017136	3,912	1.00000000000000	5,056	0.99999555130000	3,933	0.99999999978353
4,470	0.99999999053749	3,911	1.00000000000000	5,054	0.99999584964000	3,928	1.00000000000000
4,466	0.99999999032469	3,909	1.00000000000000	5,053	0.99999590649000	3,927	1.00000000000000
4,466	0.99999999054687	3,908	1.00000000000000	5,053	0.99999585515000	3,926	1.00000000000000
4,465	0.99999999054687	3,907	1.00000000000000	5,051	0.99999587820000	3,924	1.00000000000000
4,464	0.99999999069101	3,905	1.00000000000000	5,051	0.99999623487000	3,923	1.00000000000000
4,463	0.99999999069284	3,904	1.00000000000000	5,049	0.99999623616000	3,923	1.00000000000000
4,462	0.99999999016945	3,903	1.00000000000000	5,047	0.99999596254000	3,922	1.00000000000000
4,461	0.99999999083463	3,903	1.00000000000000	5,047	0.99999598408000	3,921	1.00000000000000
4,460	0.99999999110797	3,901	1.00000000000000	5,046	0.99999616264000	3,921	1.00000000000000
4,460	0.99999999090909	3,901	1.00000000000000	5,045	0.99999618780000	3,921	1.00000000000000
4,459	0.99999999083643	3,900	1.00000000000000	5,043	0.99999630844000	3,917	1.00000000000000
4,457	0.99999999075715	3,900	1.00000000000000	5,040	0.99999626334000	3,917	1.00000000000000
4,456	0.99999999138288	3,900	1.00000000000000	5,038	0.99999621267000	3,917	1.00000000000000
4,453	0.99999999138800	3,900	1.00000000000000	5,036	0.99999628930000	3,917	1.00000000000000
4,452	0.99999999138800	3,896	1.00000000000000	5,035	0.99999631401000	3,915	1.00000000000000
4,451	0.99999999145464	3,894	1.00000000000000	5,034	0.99999628619000	3,914	1.00000000000000
4,451	0.99999999195530	3,893	1.00000000000000	5,032	0.99999665170000	3,913	1.00000000000000
4,450	0.99999999164779	3,892	1.00000000000000	5,032	0.99999628744000	3,913	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,450	0.99999999189824	3,892	1.00000000000000	5,031	0.99999642611000	3,912	1.00000000000000
4,449	0.99999999177499	3,892	1.00000000000000	5,029	0.99999654365000	3,911	1.00000000000000
4,448	0.99999999171435	3,890	1.00000000000000	5,029	0.99999643149000	3,911	1.00000000000000
4,448	0.99999999171435	3,888	1.00000000000000	5,026	0.99999633795000	3,911	1.00000000000000
4,448	0.99999999177660	3,888	1.00000000000000	5,026	0.99999645239000	3,910	1.00000000000000
4,446	0.99999999177986	3,887	1.00000000000000	5,024	0.99999656828000	3,910	1.00000000000000
4,445	0.99999999208417	3,886	1.00000000000000	5,024	0.99999656366000	3,909	1.00000000000000
4,444	0.99999999196493	3,883	1.00000000000000	5,020	0.99999669755000	3,908	1.00000000000000
4,443	0.99999999196648	3,881	1.00000000000000	5,019	0.99999690307000	3,907	1.00000000000000
4,441	0.99999999226808	3,880	1.00000000000000	5,017	0.99999686266000	3,907	1.00000000000000
4,441	0.99999999215016	3,879	1.00000000000000	5,014	0.99999694507000	3,907	1.00000000000000
4,440	0.99999999221221	3,879	1.00000000000000	5,013	0.99999682146000	3,906	1.00000000000000
4,439	0.99999999232856	3,879	1.00000000000000	5,013	0.99999673748000	3,905	1.00000000000000
4,438	0.99999999233007	3,879	1.00000000000000	5,013	0.99999682146000	3,904	1.00000000000000
4,438	0.99999999190462	3,879	1.00000000000000	5,012	0.99999696285000	3,903	1.00000000000000
4,438	0.99999999190462	3,877	1.00000000000000	5,011	0.99999694404000	3,902	1.00000000000000
4,436	0.99999999255983	3,871	1.00000000000000	5,007	0.99999692777000	3,898	1.00000000000000
4,434	0.99999999256418	3,869	1.00000000000000	5,006	0.99999706101000	3,898	1.00000000000000
4,434	0.99999999289023	3,869	1.00000000000000	5,005	0.99999696741000	3,896	1.00000000000000
4,433	0.99999999221221	3,868	1.00000000000000	5,004	0.99999684652000	3,895	1.00000000000000
4,432	0.99999999267993	3,867	1.00000000000000	5,001	0.99999704451000	3,893	1.00000000000000
4,431	0.99999999278961	3,867	1.00000000000000	5,001	0.99999706001000	3,892	1.00000000000000
4,431	0.99999999233154	3,865	1.00000000000000	4,998	0.99999708373000	3,892	1.00000000000000
4,430	0.99999999284456	3,863	1.00000000000000	4,997	0.99999696741000	3,891	1.00000000000000
4,429	0.99999999284594	3,863	1.00000000000000	4,997	0.99999708180000	3,888	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,427	0.99999999301086	3,862	1.00000000000000	4,995	0.99999735136000	3,888	1.00000000000000
4,424	0.99999999306549	3,859	1.00000000000000	4,993	0.99999729939000	3,886	1.00000000000000
4,422	0.99999999317067	3,859	1.00000000000000	4,993	0.99999713735000	3,886	1.00000000000000
4,422	0.99999999284456	3,856	1.00000000000000	4,990	0.99999710233000	3,886	1.00000000000000
4,421	0.99999999322324	3,855	1.00000000000000	4,989	0.99999728107000	3,885	1.00000000000000
4,420	0.99999999337858	3,853	1.00000000000000	4,985	0.99999730122000	3,885	1.00000000000000
4,419	0.99999999348072	3,852	1.00000000000000	4,982	0.99999758264000	3,885	1.00000000000000
4,417	0.99999999322062	3,851	1.00000000000000	4,981	0.99999724950000	3,885	1.00000000000000
4,415	0.99999999353162	3,851	1.00000000000000	4,978	0.99999764553000	3,884	1.00000000000000
4,415	0.99999999332393	3,851	1.00000000000000	4,976	0.99999759846000	3,883	1.00000000000000
4,413	0.99999999337991	3,849	1.00000000000000	4,973	0.99999755082000	3,883	1.00000000000000
4,413	0.99999999367964	3,849	1.00000000000000	4,972	0.99999764634000	3,882	1.00000000000000
4,412	0.99999999377703	3,849	1.00000000000000	4,967	0.99999761522000	3,881	1.00000000000000
4,412	0.99999999337991	3,846	1.00000000000000	4,966	0.99999748901000	3,881	1.00000000000000
4,411	0.99999999377826	3,845	1.00000000000000	4,963	0.99999767987000	3,880	1.00000000000000
4,411	0.99999999372915	3,845	1.00000000000000	4,962	0.99999761563000	3,880	1.00000000000000
4,410	0.99999999391711	3,844	1.00000000000000	4,962	0.99999779601000	3,878	1.00000000000000
4,410	0.99999999348200	3,844	1.00000000000000	4,961	0.99999761603000	3,877	1.00000000000000
4,409	0.99999999353162	3,843	1.00000000000000	4,960	0.99999783804000	3,876	1.00000000000000
4,409	0.99999999357969	3,842	1.00000000000000	4,960	0.99999763320000	3,876	1.00000000000000
4,408	0.99999999396768	3,841	1.00000000000000	4,959	0.99999782452000	3,872	1.00000000000000
4,406	0.99999999401484	3,840	1.00000000000000	4,956	0.99999796212000	3,871	1.00000000000000
4,405	0.99999999396171	3,840	1.00000000000000	4,956	0.99999767832000	3,867	1.00000000000000
4,404	0.99999999410857	3,840	1.00000000000000	4,954	0.99999778169000	3,867	1.00000000000000
4,403	0.99999999419755	3,839	1.00000000000000	4,953	0.99999794858000	3,867	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,403	0.99999999415441	3,839	1.00000000000000	4,952	0.99999779675000	3,866	1.00000000000000
4,401	0.99999999419983	3,835	1.00000000000000	4,952	0.99999789607000	3,866	1.00000000000000
4,400	0.99999999405991	3,835	1.00000000000000	4,948	0.99999799116000	3,864	1.00000000000000
4,399	0.99999999437577	3,832	1.00000000000000	4,946	0.99999802846000	3,862	1.00000000000000
4,397	0.99999999450686	3,832	1.00000000000000	4,945	0.99999783987000	3,861	1.00000000000000
4,396	0.99999999446519	3,832	1.00000000000000	4,945	0.99999785566000	3,858	1.00000000000000
4,396	0.99999999419983	3,831	1.00000000000000	4,944	0.99999793610000	3,858	1.00000000000000
4,393	0.99999999455159	3,828	1.00000000000000	4,941	0.99999805631000	3,856	1.00000000000000
4,391	0.99999999471960	3,827	1.00000000000000	4,941	0.99999809197000	3,855	1.00000000000000
4,390	0.99999999467856	3,827	1.00000000000000	4,940	0.99999804426000	3,853	1.00000000000000
4,390	0.99999999454836	3,826	1.00000000000000	4,939	0.99999797702000	3,853	1.00000000000000
4,390	0.99999999467856	3,825	1.00000000000000	4,939	0.99999815459000	3,852	1.00000000000000
4,387	0.99999999484186	3,824	1.00000000000000	4,936	0.99999810725000	3,851	1.00000000000000
4,385	0.99999999488397	3,822	1.00000000000000	4,932	0.99999809297000	3,850	1.00000000000000
4,385	0.99999999488296	3,822	1.00000000000000	4,931	0.99999818111000	3,849	1.00000000000000
4,384	0.99999999492422	3,820	1.00000000000000	4,928	0.99999806973000	3,849	1.00000000000000
4,383	0.99999999500440	3,816	1.00000000000000	4,927	0.99999822842000	3,848	1.00000000000000
4,383	0.99999999503617	3,815	1.00000000000000	4,924	0.99999817958000	3,846	1.00000000000000
4,382	0.99999999508134	3,815	1.00000000000000	4,921	0.99999825164000	3,845	1.00000000000000
4,379	0.99999999484388	3,815	1.00000000000000	4,919	0.99999828372000	3,843	1.00000000000000
4,379	0.99999999515920	3,815	1.00000000000000	4,917	0.99999831921000	3,843	1.00000000000000
4,379	0.99999999515920	3,815	1.00000000000000	4,915	0.99999832034000	3,842	1.00000000000000
4,378	0.99999999534363	3,813	1.00000000000000	4,913	0.99999836213000	3,839	1.00000000000000
4,376	0.99999999519246	3,811	1.00000000000000	4,911	0.99999835372000	3,839	1.00000000000000
4,376	0.99999999527353	3,809	1.00000000000000	4,909	0.99999834126000	3,838	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,376	0.99999999531120	3,808	1.00000000000000	4,909	0.99999842706000	3,837	1.00000000000000
4,375	0.99999999538169	3,808	1.00000000000000	4,908	0.99999831892000	3,837	1.00000000000000
4,374	0.99999999519246	3,808	1.00000000000000	4,906	0.99999841585000	3,836	1.00000000000000
4,374	0.99999999508331	3,807	1.00000000000000	4,903	0.99999852807000	3,836	1.00000000000000
4,373	0.99999999538356	3,807	1.00000000000000	4,901	0.99999851864000	3,836	1.00000000000000
4,372	0.99999999534836	3,807	1.00000000000000	4,897	0.99999850066000	3,834	1.00000000000000
4,372	0.99999999545506	3,807	1.00000000000000	4,897	0.99999844907000	3,834	1.00000000000000
4,372	0.99999999545687	3,806	1.00000000000000	4,895	0.99999851864000	3,833	1.00000000000000
4,371	0.99999999552789	3,805	1.00000000000000	4,894	0.99999853958000	3,832	1.00000000000000
4,370	0.99999999545687	3,802	1.00000000000000	4,890	0.99999855965000	3,831	1.00000000000000
4,370	0.99999999523510	3,800	1.00000000000000	4,890	0.99999850066000	3,830	1.00000000000000
4,369	0.99999999552698	3,797	1.00000000000000	4,890	0.99999851068000	3,825	1.00000000000000
4,369	0.99999999552878	3,797	1.00000000000000	4,889	0.99999855843000	3,819	1.00000000000000
4,368	0.99999999527353	3,795	1.00000000000000	4,888	0.99999852041000	3,819	1.00000000000000
4,367	0.99999999538263	3,795	1.00000000000000	4,888	0.99999857645000	3,818	1.00000000000000
4,365	0.99999999545415	3,794	1.00000000000000	4,885	0.99999856864000	3,816	1.00000000000000
4,364	0.99999999566701	3,794	1.00000000000000	4,885	0.99999862404000	3,816	1.00000000000000
4,363	0.99999999545687	3,792	1.00000000000000	4,883	0.99999867083000	3,815	1.00000000000000
4,363	0.99999999577001	3,791	1.00000000000000	4,883	0.99999865189000	3,813	1.00000000000000
4,361	0.99999999580231	3,791	1.00000000000000	4,883	0.99999875438000	3,813	1.00000000000000
4,360	0.99999999590008	3,791	1.00000000000000	4,879	0.99999867083000	3,813	1.00000000000000
4,356	0.99999999580231	3,790	1.00000000000000	4,877	0.99999870405000	3,812	1.00000000000000
4,355	0.99999999596660	3,790	1.00000000000000	4,876	0.99999869579000	3,812	1.00000000000000
4,355	0.99999999599948	3,789	1.00000000000000	4,874	0.99999872965000	3,809	1.00000000000000
4,355	0.99999999599786	3,788	1.00000000000000	4,873	0.99999877188000	3,809	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,353	0.99999999590008	3,786	1.00000000000000	4,872	0.99999873119000	3,805	1.00000000000000
4,352	0.99999999609350	3,786	1.00000000000000	4,872	0.99999869669000	3,805	1.00000000000000
4,351	0.99999999624287	3,786	1.00000000000000	4,871	0.99999881959000	3,804	1.00000000000000
4,350	0.99999999596660	3,785	1.00000000000000	4,865	0.99999882083000	3,804	1.00000000000000
4,350	0.99999999602899	3,784	1.00000000000000	4,864	0.99999864222000	3,803	1.00000000000000
4,347	0.99999999621561	3,784	1.00000000000000	4,864	0.99999885086000	3,802	1.00000000000000
4,346	0.99999999627585	3,783	1.00000000000000	4,861	0.99999881227000	3,801	1.00000000000000
4,346	0.99999999627585	3,782	1.00000000000000	4,861	0.99999866050000	3,800	1.00000000000000
4,346	0.99999999624592	3,782	1.00000000000000	4,859	0.99999893886000	3,799	1.00000000000000
4,341	0.99999999642011	3,780	1.00000000000000	4,859	0.99999879659000	3,799	1.00000000000000
4,340	0.99999999644938	3,780	1.00000000000000	4,857	0.99999879701000	3,798	1.00000000000000
4,339	0.99999999644938	3,779	1.00000000000000	4,857	0.99999894624000	3,798	1.00000000000000
4,339	0.99999999653074	3,778	1.00000000000000	4,854	0.99999892498000	3,797	1.00000000000000
4,338	0.99999999633326	3,776	1.00000000000000	4,853	0.99999888246000	3,796	1.00000000000000
4,335	0.99999999661381	3,776	1.00000000000000	4,851	0.99999889617000	3,795	1.00000000000000
4,334	0.99999999661381	3,776	1.00000000000000	4,851	0.99999899441000	3,794	1.00000000000000
4,333	0.99999999644938	3,775	1.00000000000000	4,850	0.99999885146000	3,793	1.00000000000000
4,331	0.99999999669367	3,774	1.00000000000000	4,848	0.99999889674000	3,793	1.00000000000000
4,330	0.99999999672048	3,774	1.00000000000000	4,848	0.99999895389000	3,792	1.00000000000000
4,327	0.99999999658675	3,772	1.00000000000000	4,840	0.99999898902000	3,791	1.00000000000000
4,325	0.99999999666804	3,772	1.00000000000000	4,840	0.99999902158300	3,787	1.00000000000000
4,324	0.99999999699779	3,771	1.00000000000000	4,839	0.99999902243000	3,787	1.00000000000000
4,323	0.99999999687326	3,771	1.00000000000000	4,838	0.99999898936000	3,786	1.00000000000000
4,323	0.99999999677045	3,770	1.00000000000000	4,837	0.99999896148000	3,786	1.00000000000000
4,321	0.99999999700025	3,770	1.00000000000000	4,836	0.99999892646000	3,786	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,321	0.99999999677174	3,769	1.00000000000000	4,836	0.99999901477500	3,785	1.00000000000000
4,319	0.99999999682324	3,769	1.00000000000000	4,835	0.99999900941000	3,782	1.00000000000000
4,317	0.99999999707145	3,768	1.00000000000000	4,834	0.99999900856000	3,782	1.00000000000000
4,317	0.99999999702547	3,768	1.00000000000000	4,832	0.99999898266000	3,782	1.00000000000000
4,316	0.99999999704940	3,767	1.00000000000000	4,832	0.99999895477000	3,781	1.00000000000000
4,316	0.99999999707263	3,766	1.00000000000000	4,831	0.99999898266000	3,781	1.00000000000000
4,315	0.99999999711810	3,765	1.00000000000000	4,825	0.99999904209000	3,780	1.00000000000000
4,315	0.99999999709594	3,765	1.00000000000000	4,825	0.99999909929600	3,779	1.00000000000000
4,314	0.99999999709594	3,765	1.00000000000000	4,823	0.99999904241800	3,777	1.00000000000000
4,312	0.99999999700163	3,763	1.00000000000000	4,822	0.99999910396800	3,776	1.00000000000000
4,310	0.99999999704940	3,763	1.00000000000000	4,822	0.99999913448800	3,776	1.00000000000000
4,308	0.99999999723226	3,762	1.00000000000000	4,822	0.99999914589500	3,776	1.00000000000000
4,308	0.99999999709536	3,762	1.00000000000000	4,822	0.99999912356800	3,775	1.00000000000000
4,308	0.99999999727541	3,759	1.00000000000000	4,821	0.99999904893800	3,775	1.00000000000000
4,307	0.99999999739567	3,758	1.00000000000000	4,821	0.99999909819800	3,773	1.00000000000000
4,306	0.99999999735210	3,758	1.00000000000000	4,821	0.99999904828300	3,772	1.00000000000000
4,306	0.99999999727597	3,758	1.00000000000000	4,820	0.99999915744000	3,771	1.00000000000000
4,306	0.99999999730280	3,757	1.00000000000000	4,818	0.99999913402300	3,771	1.00000000000000
4,303	0.99999999748111	3,755	1.00000000000000	4,818	0.99999911758900	3,770	1.00000000000000
4,303	0.99999999730171	3,754	1.00000000000000	4,818	0.99999915834000	3,770	1.00000000000000
4,302	0.99999999750164	3,752	1.00000000000000	4,813	0.99999904109100	3,770	1.00000000000000
4,302	0.99999999735264	3,748	1.00000000000000	4,810	0.99999920333000	3,769	1.00000000000000
4,302	0.99999999739623	3,746	1.00000000000000	4,807	0.99999918154900	3,769	1.00000000000000
4,302	0.99999999725393	3,745	1.00000000000000	4,805	0.99999918097900	3,768	1.00000000000000
4,301	0.99999999750217	3,745	1.00000000000000	4,804	0.99999926039300	3,765	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,299	0.99999999746418	3,744	1.00000000000000	4,801	0.99999921888500	3,765	1.00000000000000
4,297	0.99999999750477	3,744	1.00000000000000	4,799	0.99999922512900	3,763	1.00000000000000
4,296	0.99999999742123	3,743	1.00000000000000	4,798	0.99999919271200	3,763	1.00000000000000
4,296	0.99999999752468	3,743	1.00000000000000	4,797	0.99999912280600	3,761	1.00000000000000
4,296	0.99999999752468	3,742	1.00000000000000	4,795	0.99999924515500	3,760	1.00000000000000
4,295	0.99999999752468	3,739	1.00000000000000	4,795	0.99999925030900	3,760	1.00000000000000
4,295	0.99999999740044	3,737	1.00000000000000	4,790	0.99999931366300	3,758	1.00000000000000
4,294	0.99999999754455	3,736	1.00000000000000	4,789	0.99999928482700	3,758	1.00000000000000
4,293	0.99999999756413	3,736	1.00000000000000	4,788	0.99999933668000	3,758	1.00000000000000
4,293	0.99999999772720	3,735	1.00000000000000	4,785	0.99999935868600	3,757	1.00000000000000
4,292	0.99999999763806	3,733	1.00000000000000	4,783	0.99999930906600	3,757	1.00000000000000
4,291	0.99999999763945	3,730	1.00000000000000	4,782	0.99999928534400	3,756	1.00000000000000
4,290	0.99999999766424	3,727	1.00000000000000	4,782	0.99999936746600	3,753	1.00000000000000
4,289	0.99999999768706	3,727	1.00000000000000	4,782	0.99999929958700	3,753	1.00000000000000
4,288	0.99999999768906	3,726	1.00000000000000	4,781	0.99999930931300	3,751	1.00000000000000
4,287	0.99999999771122	3,724	1.00000000000000	4,780	0.99999935857000	3,749	1.00000000000000
4,287	0.99999999768906	3,723	1.00000000000000	4,779	0.99999932324700	3,748	1.00000000000000
4,287	0.99999999774903	3,723	1.00000000000000	4,779	0.99999935880000	3,748	1.00000000000000
4,287	0.99999999774903	3,722	1.00000000000000	4,779	0.99999934597400	3,748	1.00000000000000
4,286	0.99999999774948	3,722	1.00000000000000	4,777	0.99999938030000	3,747	1.00000000000000
4,286	0.99999999773138	3,721	1.00000000000000	4,775	0.99999934562600	3,746	1.00000000000000
4,284	0.99999999776857	3,721	1.00000000000000	4,771	0.99999933738100	3,746	1.00000000000000
4,284	0.99999999776952	3,721	1.00000000000000	4,770	0.99999934187100	3,744	1.00000000000000
4,282	0.99999999787338	3,720	1.00000000000000	4,770	0.99999935857000	3,743	1.00000000000000
4,282	0.99999999785684	3,718	1.00000000000000	4,769	0.99999936405800	3,743	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,282	0.99999999784073	3,718	1.00000000000000	4,769	0.99999938084500	3,742	1.00000000000000
4,281	0.99999999774853	3,718	1.00000000000000	4,769	0.99999936350900	3,741	1.00000000000000
4,281	0.99999999785455	3,712	1.00000000000000	4,767	0.99999939368300	3,740	1.00000000000000
4,279	0.99999999776952	3,712	1.00000000000000	4,761	0.99999941758100	3,739	1.00000000000000
4,278	0.99999999790279	3,710	1.00000000000000	4,761	0.99999940986000	3,737	1.00000000000000
4,278	0.99999999787513	3,709	1.00000000000000	4,758	0.99999945953400	3,737	1.00000000000000
4,277	0.99999999798201	3,709	1.00000000000000	4,757	0.99999945195300	3,735	1.00000000000000
4,276	0.99999999790104	3,709	1.00000000000000	4,756	0.99999942195500	3,735	1.00000000000000
4,275	0.99999999790148	3,709	1.00000000000000	4,755	0.99999939777700	3,734	1.00000000000000
4,271	0.99999999804324	3,708	1.00000000000000	4,753	0.99999946329700	3,734	1.00000000000000
4,271	0.99999999793114	3,708	1.00000000000000	4,750	0.99999944149900	3,733	1.00000000000000
4,269	0.99999999809200	3,707	1.00000000000000	4,749	0.99999940587100	3,729	1.00000000000000
4,269	0.99999999810724	3,707	1.00000000000000	4,748	0.99999946775000	3,728	1.00000000000000
4,269	0.99999999809200	3,706	1.00000000000000	4,747	0.99999947453300	3,728	1.00000000000000
4,268	0.99999999812190	3,706	1.00000000000000	4,746	0.99999946396200	3,726	1.00000000000000
4,267	0.99999999812229	3,706	1.00000000000000	4,746	0.99999946405600	3,726	1.00000000000000
4,265	0.99999999804324	3,706	1.00000000000000	4,745	0.99999944504500	3,726	1.00000000000000
4,265	0.99999999815277	3,705	1.00000000000000	4,745	0.99999948185700	3,725	1.00000000000000
4,265	0.99999999815277	3,705	1.00000000000000	4,744	0.99999945982600	3,724	1.00000000000000
4,263	0.99999999819931	3,705	1.00000000000000	4,744	0.99999944514100	3,724	1.00000000000000
4,262	0.99999999807632	3,704	1.00000000000000	4,743	0.99999949568600	3,723	1.00000000000000
4,261	0.99999999813701	3,704	1.00000000000000	4,741	0.99999947796200	3,723	1.00000000000000
4,259	0.99999999829371	3,702	1.00000000000000	4,741	0.99999951972300	3,722	1.00000000000000
4,258	0.99999999832812	3,702	1.00000000000000	4,740	0.99999947069900	3,720	1.00000000000000
4,256	0.99999999834155	3,702	1.00000000000000	4,738	0.99999946405600	3,718	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,255	0.99999999833749	3,702	1.00000000000000	4,733	0.99999953280600	3,717	1.00000000000000
4,254	0.99999999835480	3,701	1.00000000000000	4,733	0.99999954264700	3,713	1.00000000000000
4,253	0.99999999836750	3,701	1.00000000000000	4,730	0.99999950974700	3,713	1.00000000000000
4,253	0.99999999827454	3,701	1.00000000000000	4,729	0.99999948923400	3,708	1.00000000000000
4,253	0.99999999838132	3,701	1.00000000000000	4,728	0.99999952373000	3,708	1.00000000000000
4,251	0.99999999842450	3,700	1.00000000000000	4,726	0.99999956448300	3,707	1.00000000000000
4,251	0.99999999839417	3,699	1.00000000000000	4,724	0.99999946001500	3,706	1.00000000000000
4,251	0.99999999839385	3,695	1.00000000000000	4,724	0.99999954247900	3,705	1.00000000000000
4,249	0.99999999846787	3,695	1.00000000000000	4,723	0.99999952032500	3,704	1.00000000000000
4,248	0.99999999846787	3,694	1.00000000000000	4,723	0.99999951705500	3,703	1.00000000000000
4,247	0.99999999844374	3,693	1.00000000000000	4,723	0.99999954321800	3,703	1.00000000000000
4,246	0.99999999850947	3,693	1.00000000000000	4,721	0.99999954639200	3,702	1.00000000000000
4,245	0.99999999839417	3,692	1.00000000000000	4,720	0.99999953617800	3,702	1.00000000000000
4,245	0.99999999852449	3,691	1.00000000000000	4,719	0.99999959648700	3,702	1.00000000000000
4,245	0.99999999840670	3,691	1.00000000000000	4,715	0.99999954289500	3,702	1.00000000000000
4,244	0.99999999858103	3,691	1.00000000000000	4,714	0.99999954639200	3,700	1.00000000000000
4,242	0.99999999855930	3,691	1.00000000000000	4,712	0.99999955547000	3,700	1.00000000000000
4,242	0.99999999844374	3,688	1.00000000000000	4,712	0.99999958867300	3,700	1.00000000000000
4,241	0.99999999857056	3,687	1.00000000000000	4,711	0.99999957399600	3,700	1.00000000000000
4,241	0.99999999846787	3,686	1.00000000000000	4,708	0.99999956797200	3,698	1.00000000000000
4,241	0.99999999857028	3,686	1.00000000000000	4,707	0.99999961854700	3,697	1.00000000000000
4,240	0.99999999858197	3,686	1.00000000000000	4,707	0.99999959961100	3,697	1.00000000000000
4,239	0.99999999859369	3,686	1.00000000000000	4,703	0.99999962902200	3,697	1.00000000000000
4,238	0.99999999862659	3,685	1.00000000000000	4,702	0.99999960757500	3,697	1.00000000000000
4,235	0.99999999864373	3,685	1.00000000000000	4,699	0.99999961093900	3,695	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,235	0.99999999865472	3,682	1.00000000000000	4,697	0.99999961059600	3,694	1.00000000000000
4,232	0.99999999875951	3,682	1.00000000000000	4,697	0.99999962366900	3,693	1.00000000000000
4,232	0.99999999873820	3,681	1.00000000000000	4,696	0.99999964160700	3,693	1.00000000000000
4,232	0.99999999860489	3,681	1.00000000000000	4,694	0.99999964180500	3,693	1.00000000000000
4,231	0.99999999872119	3,679	1.00000000000000	4,689	0.99999965172300	3,692	1.00000000000000
4,230	0.99999999862714	3,679	1.00000000000000	4,688	0.99999964960300	3,691	1.00000000000000
4,230	0.99999999872159	3,678	1.00000000000000	4,686	0.99999959939000	3,690	1.00000000000000
4,230	0.99999999873940	3,678	1.00000000000000	4,684	0.99999964193400	3,689	1.00000000000000
4,230	0.99999999873940	3,677	1.00000000000000	4,683	0.99999967745200	3,688	1.00000000000000
4,228	0.99999999879931	3,677	1.00000000000000	4,682	0.99999965404400	3,686	1.00000000000000
4,227	0.99999999876089	3,677	1.00000000000000	4,680	0.99999965893400	3,686	1.00000000000000
4,226	0.99999999878083	3,677	1.00000000000000	4,679	0.99999966174800	3,686	1.00000000000000
4,223	0.99999999880030	3,676	1.00000000000000	4,679	0.99999966168800	3,686	1.00000000000000
4,222	0.99999999881005	3,676	1.00000000000000	4,679	0.99999966174800	3,684	1.00000000000000
4,222	0.99999999884949	3,675	1.00000000000000	4,677	0.99999967979100	3,684	1.00000000000000
4,221	0.99999999883516	3,675	1.00000000000000	4,675	0.99999969521000	3,684	1.00000000000000
4,220	0.99999999877088	3,674	1.00000000000000	4,675	0.99999964947900	3,683	1.00000000000000
4,219	0.99999999881853	3,673	1.00000000000000	4,675	0.99999965454100	3,682	1.00000000000000
4,219	0.99999999885025	3,672	1.00000000000000	4,674	0.99999970355300	3,682	1.00000000000000
4,218	0.99999999892617	3,672	1.00000000000000	4,674	0.99999968872400	3,682	1.00000000000000
4,217	0.99999999880030	3,671	1.00000000000000	4,673	0.99999967517100	3,682	1.00000000000000
4,217	0.99999999879058	3,670	1.00000000000000	4,673	0.99999970361000	3,681	1.00000000000000
4,217	0.99999999887452	3,669	1.00000000000000	4,672	0.99999966370900	3,681	1.00000000000000
4,215	0.99999999890798	3,668	1.00000000000000	4,671	0.99999968019400	3,681	1.00000000000000
4,215	0.99999999889997	3,667	1.00000000000000	4,671	0.99999968895300	3,680	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,215	0.99999999884949	3,665	1.00000000000000	4,670	0.99999968245100	3,680	1.00000000000000
4,214	0.99999999891049	3,664	1.00000000000000	4,670	0.99999970150200	3,680	1.00000000000000
4,214	0.99999999891920	3,664	1.00000000000000	4,665	0.99999969346600	3,679	1.00000000000000
4,214	0.99999999892739	3,663	1.00000000000000	4,657	0.99999971002900	3,679	1.00000000000000
4,214	0.99999999891049	3,663	1.00000000000000	4,655	0.99999972221300	3,679	1.00000000000000
4,212	0.99999999893634	3,662	1.00000000000000	4,655	0.99999969984400	3,679	1.00000000000000
4,209	0.99999999894523	3,660	1.00000000000000	4,654	0.99999972195300	3,678	1.00000000000000
4,209	0.99999999889997	3,660	1.00000000000000	4,654	0.99999971417200	3,677	1.00000000000000
4,207	0.99999999900210	3,657	1.00000000000000	4,653	0.99999972800400	3,677	1.00000000000000
4,206	0.99999999899424	3,656	1.00000000000000	4,650	0.99999972019100	3,677	1.00000000000000
4,206	0.99999999901819	3,656	1.00000000000000	4,650	0.99999972211100	3,676	1.00000000000000
4,204	0.99999999902672	3,653	1.00000000000000	4,648	0.99999971448400	3,676	1.00000000000000
4,202	0.99999999905517	3,652	1.00000000000000	4,648	0.99999973945900	3,675	1.00000000000000
4,202	0.99999999905565	3,651	1.00000000000000	4,647	0.99999972398700	3,674	1.00000000000000
4,201	0.99999999896235	3,649	1.00000000000000	4,647	0.99999973577700	3,672	1.00000000000000
4,201	0.99999999897912	3,648	1.00000000000000	4,646	0.99999971847200	3,671	1.00000000000000
4,199	0.99999999906327	3,648	1.00000000000000	4,645	0.99999973558100	3,671	1.00000000000000
4,199	0.99999999906216	3,648	1.00000000000000	4,644	0.99999974108600	3,671	1.00000000000000
4,197	0.99999999911876	3,646	1.00000000000000	4,643	0.99999974512500	3,669	1.00000000000000
4,197	0.99999999908604	3,645	1.00000000000000	4,643	0.99999974676500	3,668	1.00000000000000
4,197	0.99999999903660	3,645	1.00000000000000	4,639	0.99999973217200	3,665	1.00000000000000
4,196	0.99999999909352	3,645	1.00000000000000	4,639	0.99999976055300	3,664	1.00000000000000
4,196	0.99999999909352	3,643	1.00000000000000	4,632	0.99999976909700	3,663	1.00000000000000
4,194	0.99999999910356	3,643	1.00000000000000	4,626	0.99999973197800	3,663	1.00000000000000
4,194	0.99999999913876	3,643	1.00000000000000	4,619	0.99999979238700	3,662	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,193	0.99999999919825	3,642	1.00000000000000	4,618	0.99999978659500	3,661	1.00000000000000
4,193	0.99999999915475	3,642	1.00000000000000	4,618	0.99999978049300	3,660	1.00000000000000
4,192	0.99999999913967	3,642	1.00000000000000	4,617	0.99999978470300	3,659	1.00000000000000
4,192	0.99999999913967	3,641	1.00000000000000	4,617	0.99999978201100	3,659	1.00000000000000
4,192	0.99999999917520	3,641	1.00000000000000	4,616	0.99999978177400	3,658	1.00000000000000
4,190	0.99999999916895	3,640	1.00000000000000	4,616	0.99999977855300	3,652	1.00000000000000
4,190	0.99999999917553	3,639	1.00000000000000	4,614	0.99999978628500	3,652	1.00000000000000
4,190	0.99999999913851	3,639	1.00000000000000	4,611	0.99999978494300	3,651	1.00000000000000
4,188	0.99999999918453	3,639	1.00000000000000	4,610	0.99999979516900	3,651	1.00000000000000
4,188	0.99999999909352	3,638	1.00000000000000	4,609	0.99999981197100	3,650	1.00000000000000
4,188	0.99999999910356	3,638	1.00000000000000	4,608	0.99999976082200	3,649	1.00000000000000
4,187	0.99999999921242	3,637	1.00000000000000	4,607	0.99999979524500	3,648	1.00000000000000
4,185	0.99999999920655	3,637	1.00000000000000	4,607	0.99999981459700	3,648	1.00000000000000
4,184	0.99999999921926	3,636	1.00000000000000	4,606	0.99999978808800	3,647	1.00000000000000
4,183	0.99999999917570	3,636	1.00000000000000	4,605	0.99999980093000	3,647	1.00000000000000
4,180	0.99999999926551	3,636	1.00000000000000	4,605	0.99999978961100	3,647	1.00000000000000
4,179	0.99999999930011	3,636	1.00000000000000	4,604	0.99999978961100	3,647	1.00000000000000
4,179	0.99999999931735	3,635	1.00000000000000	4,604	0.99999980122000	3,646	1.00000000000000
4,178	0.99999999930161	3,634	1.00000000000000	4,604	0.99999979396700	3,646	1.00000000000000
4,177	0.99999999931972	3,634	1.00000000000000	4,603	0.99999980261600	3,646	1.00000000000000
4,177	0.99999999933836	3,633	1.00000000000000	4,601	0.99999981463100	3,645	1.00000000000000
4,176	0.99999999933046	3,633	1.00000000000000	4,599	0.99999979543300	3,645	1.00000000000000
4,176	0.99999999933092	3,632	1.00000000000000	4,596	0.99999980261600	3,645	1.00000000000000
4,176	0.99999999933120	3,632	1.00000000000000	4,596	0.99999979976200	3,643	1.00000000000000
4,174	0.99999999932895	3,632	1.00000000000000	4,595	0.99999982490700	3,643	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,172	0.99999999938574	3,630	1.00000000000000	4,595	0.99999977887900	3,642	1.00000000000000
4,172	0.99999999928688	3,630	1.00000000000000	4,594	0.99999980400200	3,642	1.00000000000000
4,168	0.99999999937611	3,629	1.00000000000000	4,594	0.99999979979700	3,641	1.00000000000000
4,167	0.99999999933930	3,629	1.00000000000000	4,594	0.99999981595000	3,640	1.00000000000000
4,166	0.99999999938672	3,628	1.00000000000000	4,593	0.99999978644300	3,640	1.00000000000000
4,166	0.99999999942547	3,627	1.00000000000000	4,590	0.99999982392400	3,640	1.00000000000000
4,165	0.99999999947960	3,627	1.00000000000000	4,589	0.99999981224700	3,640	1.00000000000000
4,164	0.99999999944910	3,627	1.00000000000000	4,587	0.99999983232800	3,640	1.00000000000000
4,164	0.99999999946531	3,627	1.00000000000000	4,584	0.99999982894400	3,640	1.00000000000000
4,164	0.99999999937095	3,625	1.00000000000000	4,582	0.99999984512800	3,640	1.00000000000000
4,163	0.99999999938607	3,624	1.00000000000000	4,580	0.99999983616700	3,639	1.00000000000000
4,163	0.99999999936589	3,622	1.00000000000000	4,576	0.99999983734600	3,637	1.00000000000000
4,162	0.99999999946630	3,621	1.00000000000000	4,576	0.99999984076800	3,636	1.00000000000000
4,161	0.99999999947507	3,620	1.00000000000000	4,573	0.99999984850500	3,636	1.00000000000000
4,161	0.99999999949132	3,620	1.00000000000000	4,573	0.99999984417900	3,635	1.00000000000000
4,161	0.99999999947062	3,618	1.00000000000000	4,572	0.99999984085500	3,635	1.00000000000000
4,161	0.99999999947507	3,617	1.00000000000000	4,572	0.99999984312300	3,634	1.00000000000000
4,160	0.99999999949132	3,617	1.00000000000000	4,571	0.99999985277600	3,632	1.00000000000000
4,160	0.99999999948198	3,615	1.00000000000000	4,571	0.99999984640100	3,632	1.00000000000000
4,159	0.99999999949173	3,614	1.00000000000000	4,570	0.99999984642900	3,632	1.00000000000000
4,159	0.99999999951634	3,614	1.00000000000000	4,570	0.99999985701900	3,631	1.00000000000000
4,158	0.99999999949814	3,614	1.00000000000000	4,569	0.99999985192700	3,630	1.00000000000000
4,158	0.99999999949856	3,613	1.00000000000000	4,568	0.99999984628600	3,630	1.00000000000000
4,158	0.99999999950902	3,613	1.00000000000000	4,567	0.99999985184400	3,629	1.00000000000000
4,157	0.99999999944853	3,612	1.00000000000000	4,567	0.99999984193400	3,629	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,157	0.99999999949856	3,612	1.00000000000000	4,565	0.99999984734600	3,628	1.00000000000000
4,157	0.99999999946630	3,612	1.00000000000000	4,564	0.99999985822600	3,628	1.00000000000000
4,153	0.99999999958057	3,611	1.00000000000000	4,563	0.99999984426400	3,627	1.00000000000000
4,153	0.99999999952665	3,611	1.00000000000000	4,563	0.99999985071700	3,627	1.00000000000000
4,153	0.99999999949173	3,611	1.00000000000000	4,560	0.99999986412000	3,626	1.00000000000000
4,151	0.99999999956070	3,610	1.00000000000000	4,560	0.99999985518200	3,626	1.00000000000000
4,151	0.99999999956070	3,608	1.00000000000000	4,559	0.99999984533300	3,625	1.00000000000000
4,149	0.99999999958219	3,608	1.00000000000000	4,557	0.99999985088200	3,625	1.00000000000000
4,149	0.99999999959818	3,608	1.00000000000000	4,556	0.99999985931000	3,624	1.00000000000000
4,148	0.99999999959826	3,608	1.00000000000000	4,552	0.99999985518200	3,624	1.00000000000000
4,147	0.99999999951740	3,608	1.00000000000000	4,550	0.99999984521700	3,624	1.00000000000000
4,146	0.99999999960146	3,607	1.00000000000000	4,549	0.99999985931000	3,624	1.00000000000000
4,146	0.99999999960146	3,606	1.00000000000000	4,547	0.99999987202300	3,623	1.00000000000000
4,145	0.99999999963129	3,606	1.00000000000000	4,547	0.99999986235400	3,622	1.00000000000000
4,145	0.99999999963077	3,606	1.00000000000000	4,545	0.99999986909500	3,622	1.00000000000000
4,144	0.99999999964406	3,606	1.00000000000000	4,545	0.99999988085900	3,621	1.00000000000000
4,144	0.99999999963115	3,606	1.00000000000000	4,545	0.99999986434900	3,619	1.00000000000000
4,143	0.99999999964550	3,606	1.00000000000000	4,541	0.99999987653100	3,618	1.00000000000000
4,142	0.99999999959488	3,605	1.00000000000000	4,541	0.99999987837700	3,617	1.00000000000000
4,142	0.99999999965371	3,604	1.00000000000000	4,541	0.99999988425600	3,617	1.00000000000000
4,141	0.99999999963981	3,604	1.00000000000000	4,541	0.99999986827400	3,616	1.00000000000000
4,140	0.99999999964857	3,604	1.00000000000000	4,536	0.99999988180900	3,616	1.00000000000000
4,139	0.99999999961021	3,602	1.00000000000000	4,536	0.99999987840000	3,616	1.00000000000000
4,137	0.99999999966881	3,602	1.00000000000000	4,534	0.99999988350400	3,614	1.00000000000000
4,137	0.99999999975664	3,601	1.00000000000000	4,534	0.99999988675300	3,612	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,136	0.99999999974263	3,601	1.00000000000000	4,533	0.99999988526100	3,612	1.00000000000000
4,136	0.99999999970762	3,598	1.00000000000000	4,532	0.99999988339300	3,611	1.00000000000000
4,134	0.99999999974452	3,598	1.00000000000000	4,531	0.99999989318500	3,610	1.00000000000000
4,134	0.99999999974858	3,596	1.00000000000000	4,531	0.99999988274200	3,609	1.00000000000000
4,132	0.99999999975336	3,595	1.00000000000000	4,529	0.99999988183100	3,608	1.00000000000000
4,132	0.99999999977899	3,595	1.00000000000000	4,528	0.99999988183100	3,605	1.00000000000000
4,132	0.99999999975825	3,595	1.00000000000000	4,527	0.99999989167200	3,605	1.00000000000000
4,130	0.99999999970700	3,595	1.00000000000000	4,525	0.99999986724700	3,604	1.00000000000000
4,128	0.99999999977977	3,593	1.00000000000000	4,525	0.99999988189600	3,603	1.00000000000000
4,125	0.99999999978502	3,593	1.00000000000000	4,525	0.99999988843200	3,601	1.00000000000000
4,125	0.99999999978949	3,592	1.00000000000000	4,523	0.99999989782400	3,601	1.00000000000000
4,124	0.99999999985906	3,591	1.00000000000000	4,523	0.99999989097400	3,600	1.00000000000000
4,122	0.99999999983245	3,590	1.00000000000000	4,520	0.99999989003200	3,600	1.00000000000000
4,122	0.99999999981486	3,589	1.00000000000000	4,519	0.99999987377100	3,599	1.00000000000000
4,121	1.00000000000000	3,589	1.00000000000000	4,518	0.99999989644300	3,598	1.00000000000000
4,121	0.99999999985970	3,588	1.00000000000000	4,513	0.99999989256900	3,598	1.00000000000000
4,120	0.99999999978506	3,584	1.00000000000000	4,512	0.99999990708020	3,598	1.00000000000000
4,119	0.99999999986085	3,583	1.00000000000000	4,511	0.99999990013330	3,597	1.00000000000000
4,119	0.99999999983465	3,582	1.00000000000000	4,510	0.99999989413200	3,597	1.00000000000000
4,118	0.99999999986085	3,582	1.00000000000000	4,509	0.99999990367440	3,597	1.00000000000000
4,117	0.99999999979414	3,582	1.00000000000000	4,508	0.99999989566100	3,596	1.00000000000000
4,117	1.00000000000000	3,582	1.00000000000000	4,507	0.99999990784260	3,594	1.00000000000000
4,116	1.00000000000000	3,581	1.00000000000000	4,504	0.99999990087980	3,594	1.00000000000000
4,115	1.00000000000000	3,581	1.00000000000000	4,503	0.99999990433240	3,594	1.00000000000000
4,115	1.00000000000000	3,581	1.00000000000000	4,502	0.99999990784260	3,593	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,114	1.00000000000000	3,580	1.00000000000000	4,502	0.99999990581920	3,592	1.00000000000000
4,112	1.00000000000000	3,580	1.00000000000000	4,498	0.99999990723820	3,591	1.00000000000000
4,112	1.00000000000000	3,579	1.00000000000000	4,494	0.99999991058080	3,588	1.00000000000000
4,109	1.00000000000000	3,579	1.00000000000000	4,494	0.99999990918910	3,588	1.00000000000000
4,109	1.00000000000000	3,579	1.00000000000000	4,491	0.99999991740610	3,587	1.00000000000000
4,109	1.00000000000000	3,579	1.00000000000000	4,490	0.99999991569580	3,587	1.00000000000000
4,109	1.00000000000000	3,579	1.00000000000000	4,488	0.99999989938500	3,586	1.00000000000000
4,108	1.00000000000000	3,578	1.00000000000000	4,488	0.99999991492490	3,585	1.00000000000000
4,107	1.00000000000000	3,578	1.00000000000000	4,487	0.99999992097470	3,584	1.00000000000000
4,104	1.00000000000000	3,577	1.00000000000000	4,485	0.99999991631340	3,584	1.00000000000000
4,103	1.00000000000000	3,577	1.00000000000000	4,483	0.99999991924960	3,583	1.00000000000000
4,102	1.00000000000000	3,576	1.00000000000000	4,483	0.99999990641490	3,583	1.00000000000000
4,102	1.00000000000000	3,576	1.00000000000000	4,480	0.99999992650630	3,581	1.00000000000000
4,100	1.00000000000000	3,576	1.00000000000000	4,477	0.99999992106300	3,580	1.00000000000000
4,100	1.00000000000000	3,576	1.00000000000000	4,476	0.99999992597580	3,580	1.00000000000000
4,099	1.00000000000000	3,575	1.00000000000000	4,474	0.99999991871380	3,579	1.00000000000000
4,099	1.00000000000000	3,573	1.00000000000000	4,473	0.99999991692130	3,579	1.00000000000000
4,097	1.00000000000000	3,572	1.00000000000000	4,471	0.99999992915710	3,578	1.00000000000000
4,097	1.00000000000000	3,570	1.00000000000000	4,471	0.99999992447050	3,576	1.00000000000000
4,095	1.00000000000000	3,569	1.00000000000000	4,470	0.99999991370900	3,576	1.00000000000000
4,093	1.00000000000000	3,569	1.00000000000000	4,470	0.99999992715490	3,575	1.00000000000000
4,092	1.00000000000000	3,568	1.00000000000000	4,469	0.99999992500680	3,574	1.00000000000000
4,092	1.00000000000000	3,567	1.00000000000000	4,469	0.99999992652080	3,574	1.00000000000000
4,091	1.00000000000000	3,566	1.00000000000000	4,469	0.99999991058080	3,574	1.00000000000000
4,090	1.00000000000000	3,566	1.00000000000000	4,463	0.99999992976210	3,574	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,090	1.00000000000000	3,565	1.00000000000000	4,461	0.99999991920370	3,573	1.00000000000000
4,087	1.00000000000000	3,565	1.00000000000000	4,460	0.99999992818580	3,573	1.00000000000000
4,087	1.00000000000000	3,564	1.00000000000000	4,460	0.99999993279150	3,572	1.00000000000000
4,087	1.00000000000000	3,564	1.00000000000000	4,458	0.99999993122680	3,571	1.00000000000000
4,085	1.00000000000000	3,563	1.00000000000000	4,457	0.99999993704940	3,571	1.00000000000000
4,084	1.00000000000000	3,563	1.00000000000000	4,453	0.99999993317670	3,570	1.00000000000000
4,081	1.00000000000000	3,562	1.00000000000000	4,453	0.99999993619840	3,570	1.00000000000000
4,080	1.00000000000000	3,562	1.00000000000000	4,452	0.99999993976180	3,570	1.00000000000000
4,080	1.00000000000000	3,562	1.00000000000000	4,452	0.99999993427600	3,570	1.00000000000000
4,080	1.00000000000000	3,561	1.00000000000000	4,450	0.99999993524790	3,570	1.00000000000000
4,080	1.00000000000000	3,561	1.00000000000000	4,449	0.99999993230550	3,569	1.00000000000000
4,079	1.00000000000000	3,561	1.00000000000000	4,448	0.99999993230550	3,568	1.00000000000000
4,078	1.00000000000000	3,561	1.00000000000000	4,448	0.99999993885110	3,567	1.00000000000000
4,078	1.00000000000000	3,560	1.00000000000000	4,447	0.99999993748860	3,567	1.00000000000000
4,077	1.00000000000000	3,560	1.00000000000000	4,447	0.99999993328990	3,566	1.00000000000000
4,076	1.00000000000000	3,560	1.00000000000000	4,447	0.99999993667320	3,566	1.00000000000000
4,076	1.00000000000000	3,560	1.00000000000000	4,447	0.99999993563150	3,566	1.00000000000000
4,075	1.00000000000000	3,560	1.00000000000000	4,446	0.99999994027300	3,565	1.00000000000000
4,075	1.00000000000000	3,557	1.00000000000000	4,445	0.99999994324200	3,564	1.00000000000000
4,074	1.00000000000000	3,557	1.00000000000000	4,445	0.99999993892110	3,563	1.00000000000000
4,074	1.00000000000000	3,556	1.00000000000000	4,443	0.99999993842800	3,563	1.00000000000000
4,074	1.00000000000000	3,556	1.00000000000000	4,443	0.99999993932470	3,561	1.00000000000000
4,073	1.00000000000000	3,556	1.00000000000000	4,441	0.99999994198950	3,560	1.00000000000000
4,070	1.00000000000000	3,553	1.00000000000000	4,437	0.99999994196720	3,560	1.00000000000000
4,070	1.00000000000000	3,552	1.00000000000000	4,437	0.99999994161210	3,559	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,070	1.00000000000000	3,552	1.00000000000000	4,435	0.99999994371690	3,558	1.00000000000000
4,065	1.00000000000000	3,551	1.00000000000000	4,434	0.99999993940480	3,558	1.00000000000000
4,065	1.00000000000000	3,551	1.00000000000000	4,434	0.99999993130510	3,558	1.00000000000000
4,065	1.00000000000000	3,551	1.00000000000000	4,432	0.99999994334040	3,556	1.00000000000000
4,064	1.00000000000000	3,550	1.00000000000000	4,432	0.99999993181960	3,556	1.00000000000000
4,063	1.00000000000000	3,550	1.00000000000000	4,429	0.99999993519900	3,554	1.00000000000000
4,063	1.00000000000000	3,550	1.00000000000000	4,428	0.99999994285550	3,553	1.00000000000000
4,061	1.00000000000000	3,549	1.00000000000000	4,428	0.99999994248450	3,553	1.00000000000000
4,060	1.00000000000000	3,549	1.00000000000000	4,426	0.99999994372760	3,553	1.00000000000000
4,057	1.00000000000000	3,549	1.00000000000000	4,426	0.99999994655810	3,552	1.00000000000000
4,056	1.00000000000000	3,549	1.00000000000000	4,426	0.99999993662540	3,552	1.00000000000000
4,056	1.00000000000000	3,548	1.00000000000000	4,426	0.99999994410330	3,552	1.00000000000000
4,053	1.00000000000000	3,548	1.00000000000000	4,425	0.99999994778080	3,552	1.00000000000000
4,053	1.00000000000000	3,547	1.00000000000000	4,425	0.99999994892140	3,552	1.00000000000000
4,051	1.00000000000000	3,546	1.00000000000000	4,425	0.99999994779090	3,552	1.00000000000000
4,051	1.00000000000000	3,546	1.00000000000000	4,424	0.99999994893160	3,551	1.00000000000000
4,051	1.00000000000000	3,545	1.00000000000000	4,423	0.99999994497350	3,551	1.00000000000000
4,050	1.00000000000000	3,545	1.00000000000000	4,423	0.99999994579710	3,551	1.00000000000000
4,050	1.00000000000000	3,545	1.00000000000000	4,420	0.99999994067800	3,547	1.00000000000000
4,050	1.00000000000000	3,544	1.00000000000000	4,420	0.99999995013110	3,547	1.00000000000000
4,049	1.00000000000000	3,544	1.00000000000000	4,419	0.99999994811940	3,547	1.00000000000000
4,049	1.00000000000000	3,544	1.00000000000000	4,419	0.99999994860130	3,547	1.00000000000000
4,049	1.00000000000000	3,544	1.00000000000000	4,418	0.99999994697260	3,546	1.00000000000000
4,049	1.00000000000000	3,544	1.00000000000000	4,417	0.99999994541290	3,546	1.00000000000000
4,048	1.00000000000000	3,543	1.00000000000000	4,414	0.99999994896110	3,546	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,048	1.00000000000000	3,542	1.00000000000000	4,414	0.99999994971460	3,546	1.00000000000000
4,048	1.00000000000000	3,542	1.00000000000000	4,413	0.99999994897080	3,545	1.00000000000000
4,048	1.00000000000000	3,541	1.00000000000000	4,413	0.99999994822050	3,545	1.00000000000000
4,048	1.00000000000000	3,541	1.00000000000000	4,412	0.99999995540040	3,544	1.00000000000000
4,047	1.00000000000000	3,540	1.00000000000000	4,408	0.99999995193210	3,544	1.00000000000000
4,047	1.00000000000000	3,539	1.00000000000000	4,408	0.99999995157890	3,543	1.00000000000000
4,045	1.00000000000000	3,539	1.00000000000000	4,406	0.99999995671810	3,543	1.00000000000000
4,045	1.00000000000000	3,538	1.00000000000000	4,406	0.99999995373440	3,543	1.00000000000000
4,041	1.00000000000000	3,538	1.00000000000000	4,402	0.99999995477500	3,543	1.00000000000000
4,040	1.00000000000000	3,537	1.00000000000000	4,401	0.99999995766090	3,542	1.00000000000000
4,039	1.00000000000000	3,536	1.00000000000000	4,399	0.99999995197830	3,541	1.00000000000000
4,039	1.00000000000000	3,535	1.00000000000000	4,399	0.99999995404870	3,539	1.00000000000000
4,038	1.00000000000000	3,535	1.00000000000000	4,396	0.99999995639460	3,538	1.00000000000000
4,038	1.00000000000000	3,535	1.00000000000000	4,396	0.99999995922910	3,538	1.00000000000000
4,037	1.00000000000000	3,534	1.00000000000000	4,396	0.99999995007360	3,537	1.00000000000000
4,037	1.00000000000000	3,533	1.00000000000000	4,390	0.99999996100090	3,537	1.00000000000000
4,036	1.00000000000000	3,532	1.00000000000000	4,389	0.99999995676770	3,535	1.00000000000000
4,036	1.00000000000000	3,531	1.00000000000000	4,388	0.99999995959140	3,535	1.00000000000000
4,036	1.00000000000000	3,531	1.00000000000000	4,385	0.99999996076390	3,535	1.00000000000000
4,036	1.00000000000000	3,531	1.00000000000000	4,384	0.99999996018670	3,534	1.00000000000000
4,035	1.00000000000000	3,530	1.00000000000000	4,384	0.99999996164840	3,533	1.00000000000000
4,034	1.00000000000000	3,528	1.00000000000000	4,384	0.99999996189510	3,533	1.00000000000000
4,031	1.00000000000000	3,528	1.00000000000000	4,383	0.99999996043850	3,531	1.00000000000000
4,031	1.00000000000000	3,528	1.00000000000000	4,383	0.99999995956840	3,530	1.00000000000000
4,031	1.00000000000000	3,528	1.00000000000000	4,380	0.99999996219890	3,530	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,029	1.00000000000000	3,527	1.00000000000000	4,380	0.99999995959140	3,530	1.00000000000000
4,029	1.00000000000000	3,527	1.00000000000000	4,378	0.99999996245060	3,529	1.00000000000000
4,028	1.00000000000000	3,525	1.00000000000000	4,376	0.99999996327320	3,527	1.00000000000000
4,027	1.00000000000000	3,524	1.00000000000000	4,375	0.99999996106860	3,527	1.00000000000000
4,026	1.00000000000000	3,524	1.00000000000000	4,374	0.99999996644040	3,525	1.00000000000000
4,026	1.00000000000000	3,524	1.00000000000000	4,374	0.99999996412330	3,523	1.00000000000000
4,026	1.00000000000000	3,524	1.00000000000000	4,373	0.99999996333710	3,522	1.00000000000000
4,026	1.00000000000000	3,523	1.00000000000000	4,373	0.99999996329490	3,519	1.00000000000000
4,024	1.00000000000000	3,522	1.00000000000000	4,370	0.99999996514270	3,518	1.00000000000000
4,023	1.00000000000000	3,522	1.00000000000000	4,368	0.99999996305840	3,518	1.00000000000000
4,019	1.00000000000000	3,522	1.00000000000000	4,366	0.99999996386900	3,518	1.00000000000000
4,019	1.00000000000000	3,522	1.00000000000000	4,365	0.99999996647340	3,518	1.00000000000000
4,019	1.00000000000000	3,521	1.00000000000000	4,364	0.99999996743920	3,517	1.00000000000000
4,018	1.00000000000000	3,521	1.00000000000000	4,363	0.99999996467250	3,516	1.00000000000000
4,018	1.00000000000000	3,520	1.00000000000000	4,362	0.99999996720750	3,515	1.00000000000000
4,018	1.00000000000000	3,520	1.00000000000000	4,361	0.99999996465920	3,515	1.00000000000000
4,016	1.00000000000000	3,520	1.00000000000000	4,359	0.99999996723280	3,515	1.00000000000000
4,016	1.00000000000000	3,520	1.00000000000000	4,351	0.99999997009000	3,515	1.00000000000000
4,015	1.00000000000000	3,519	1.00000000000000	4,350	0.99999996866810	3,515	1.00000000000000
4,014	1.00000000000000	3,519	1.00000000000000	4,350	0.99999996843320	3,514	1.00000000000000
4,014	1.00000000000000	3,519	1.00000000000000	4,348	0.99999996963140	3,514	1.00000000000000
4,013	1.00000000000000	3,518	1.00000000000000	4,348	0.99999996567370	3,514	1.00000000000000
4,012	1.00000000000000	3,518	1.00000000000000	4,346	0.99999997031390	3,514	1.00000000000000
4,012	1.00000000000000	3,518	1.00000000000000	4,344	0.99999996821170	3,513	1.00000000000000
4,011	1.00000000000000	3,518	1.00000000000000	4,343	0.99999997076480	3,512	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
4,011	1.00000000000000	3,517	1.00000000000000	4,342	0.99999997307610	3,511	1.00000000000000
4,010	1.00000000000000	3,517	1.00000000000000	4,341	0.99999997120950	3,511	1.00000000000000
4,010	1.00000000000000	3,516	1.00000000000000	4,338	0.99999997449530	3,510	1.00000000000000
4,010	1.00000000000000	3,516	1.00000000000000	4,338	0.99999997369900	3,510	1.00000000000000
4,009	1.00000000000000	3,516	1.00000000000000	4,337	0.99999997246300	3,510	1.00000000000000
4,009	1.00000000000000	3,516	1.00000000000000	4,336	0.99999997332930	3,508	1.00000000000000
4,009	1.00000000000000	3,515	1.00000000000000	4,334	0.99999997142920	3,508	1.00000000000000
4,007	1.00000000000000	3,515	1.00000000000000	4,334	0.99999997468650	3,506	1.00000000000000
4,007	1.00000000000000	3,514	1.00000000000000	4,334	0.99999997054000	3,506	1.00000000000000
4,004	1.00000000000000	3,513	1.00000000000000	4,334	0.99999997489560	3,505	1.00000000000000
4,004	1.00000000000000	3,512	1.00000000000000	4,333	0.99999997312400	3,504	1.00000000000000
4,002	1.00000000000000	3,512	1.00000000000000	4,333	0.99999997526820	3,502	1.00000000000000
4,002	1.00000000000000	3,511	1.00000000000000	4,332	0.99999997329270	3,502	1.00000000000000
3,999	1.00000000000000	3,510	1.00000000000000	4,330	0.99999997451070	3,502	1.00000000000000
3,999	1.00000000000000	3,510	1.00000000000000	4,328	0.99999996960790	3,501	1.00000000000000
3,997	1.00000000000000	3,508	1.00000000000000	4,327	0.99999997491060	3,500	1.00000000000000
3,997	1.00000000000000	3,508	1.00000000000000	4,325	0.99999997507380	3,500	1.00000000000000
3,996	1.00000000000000	3,508	1.00000000000000	4,324	0.99999997353570	3,500	1.00000000000000
3,996	1.00000000000000	3,508	1.00000000000000	4,324	0.99999997353570	3,500	1.00000000000000
3,994	1.00000000000000	3,507	1.00000000000000	4,324	0.99999997492520	3,500	1.00000000000000
3,993	1.00000000000000	3,506	1.00000000000000	4,322	0.99999997604720	3,499	1.00000000000000
3,992	1.00000000000000	3,505	1.00000000000000	4,322	0.99999997673160	3,498	1.00000000000000
3,991	1.00000000000000	3,505	1.00000000000000	4,321	0.99999997566840	3,498	1.00000000000000
3,989	1.00000000000000	3,505	1.00000000000000	4,321	0.99999997031390	3,498	1.00000000000000
3,988	1.00000000000000	3,504	1.00000000000000	4,321	0.99999997760240	3,498	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,988	1.00000000000000	3,504	1.00000000000000	4,318	0.99999997677310	3,498	1.00000000000000
3,988	1.00000000000000	3,504	1.00000000000000	4,318	0.99999997492040	3,498	1.00000000000000
3,988	1.00000000000000	3,503	1.00000000000000	4,317	0.99999997694990	3,498	1.00000000000000
3,987	1.00000000000000	3,503	1.00000000000000	4,316	0.99999997581880	3,496	1.00000000000000
3,986	1.00000000000000	3,500	1.00000000000000	4,316	0.99999997860660	3,494	1.00000000000000
3,985	1.00000000000000	3,499	1.00000000000000	4,314	0.99999997729730	3,494	1.00000000000000
3,985	1.00000000000000	3,499	1.00000000000000	4,313	0.99999997694990	3,493	1.00000000000000
3,984	1.00000000000000	3,498	1.00000000000000	4,311	0.99999997797740	3,492	1.00000000000000
3,981	1.00000000000000	3,498	1.00000000000000	4,310	0.99999997331380	3,491	1.00000000000000
3,981	1.00000000000000	3,497	1.00000000000000	4,310	0.99999997746830	3,490	1.00000000000000
3,978	1.00000000000000	3,497	1.00000000000000	4,310	0.99999997548810	3,490	1.00000000000000
3,978	1.00000000000000	3,497	1.00000000000000	4,306	0.99999997694550	3,490	1.00000000000000
3,977	1.00000000000000	3,497	1.00000000000000	4,305	0.99999997941340	3,490	1.00000000000000
3,977	1.00000000000000	3,496	1.00000000000000	4,304	0.99999997746400	3,489	1.00000000000000
3,976	1.00000000000000	3,495	1.00000000000000	4,303	0.99999997746830	3,488	1.00000000000000
3,976	1.00000000000000	3,495	1.00000000000000	4,302	0.99999997911690	3,487	1.00000000000000
3,976	1.00000000000000	3,495	1.00000000000000	4,302	0.99999997880700	3,487	1.00000000000000
3,972	1.00000000000000	3,495	1.00000000000000	4,301	0.99999998032380	3,486	1.00000000000000
3,972	1.00000000000000	3,495	1.00000000000000	4,301	0.99999997928080	3,486	1.00000000000000
3,967	1.00000000000000	3,494	1.00000000000000	4,300	0.99999997814360	3,485	1.00000000000000
3,966	1.00000000000000	3,494	1.00000000000000	4,298	0.99999997831500	3,485	1.00000000000000
3,965	1.00000000000000	3,490	1.00000000000000	4,298	0.99999997959170	3,484	1.00000000000000
3,964	1.00000000000000	3,489	1.00000000000000	4,298	0.99999997847790	3,483	1.00000000000000
3,961	1.00000000000000	3,488	1.00000000000000	4,295	0.99999998108600	3,482	1.00000000000000
3,960	1.00000000000000	3,488	1.00000000000000	4,290	0.99999997897090	3,481	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,960	1.00000000000000	3,488	1.00000000000000	4,289	0.99999998205620	3,481	1.00000000000000
3,959	1.00000000000000	3,488	1.00000000000000	4,288	0.99999998152360	3,480	1.00000000000000
3,959	1.00000000000000	3,486	1.00000000000000	4,288	0.99999998205620	3,479	1.00000000000000
3,957	1.00000000000000	3,486	1.00000000000000	4,286	0.99999997729730	3,479	1.00000000000000
3,957	1.00000000000000	3,486	1.00000000000000	4,285	0.99999998049470	3,479	1.00000000000000
3,957	1.00000000000000	3,485	1.00000000000000	4,283	0.99999998066350	3,479	1.00000000000000
3,956	1.00000000000000	3,485	1.00000000000000	4,283	0.99999998066350	3,477	1.00000000000000
3,956	1.00000000000000	3,484	1.00000000000000	4,281	0.99999998248290	3,476	1.00000000000000
3,955	1.00000000000000	3,484	1.00000000000000	4,274	0.99999998194890	3,476	1.00000000000000
3,955	1.00000000000000	3,484	1.00000000000000	4,274	0.99999998194890	3,476	1.00000000000000
3,955	1.00000000000000	3,483	1.00000000000000	4,274	0.99999998390440	3,475	1.00000000000000
3,954	1.00000000000000	3,482	1.00000000000000	4,272	0.99999998426610	3,475	1.00000000000000
3,953	1.00000000000000	3,481	1.00000000000000	4,272	0.99999997989490	3,475	1.00000000000000
3,952	1.00000000000000	3,480	1.00000000000000	4,271	0.99999998248290	3,475	1.00000000000000
3,951	1.00000000000000	3,480	1.00000000000000	4,271	0.99999998106680	3,475	1.00000000000000
3,951	1.00000000000000	3,478	1.00000000000000	4,271	0.99999998236620	3,474	1.00000000000000
3,950	1.00000000000000	3,478	1.00000000000000	4,269	0.99999998262970	3,470	1.00000000000000
3,949	1.00000000000000	3,478	1.00000000000000	4,269	0.99999998301920	3,470	1.00000000000000
3,949	1.00000000000000	3,476	1.00000000000000	4,265	0.99999998315710	3,468	1.00000000000000
3,949	1.00000000000000	3,476	1.00000000000000	4,264	0.99999998415500	3,468	1.00000000000000
3,949	1.00000000000000	3,476	1.00000000000000	4,262	0.99999998463240	3,468	1.00000000000000
3,947	1.00000000000000	3,476	1.00000000000000	4,261	0.99999998380070	3,467	1.00000000000000
3,946	1.00000000000000	3,474	1.00000000000000	4,259	0.99999998341450	3,467	1.00000000000000
3,946	1.00000000000000	3,473	1.00000000000000	4,259	0.99999998405480	3,465	1.00000000000000
3,944	1.00000000000000	3,472	1.00000000000000	4,257	0.99999998476280	3,464	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,942	1.00000000000000	3,471	1.00000000000000	4,257	0.99999998501300	3,464	1.00000000000000
3,942	1.00000000000000	3,470	1.00000000000000	4,256	0.99999998511130	3,462	1.00000000000000
3,942	1.00000000000000	3,470	1.00000000000000	4,255	0.99999998569020	3,462	1.00000000000000
3,940	1.00000000000000	3,470	1.00000000000000	4,254	0.99999998313390	3,462	1.00000000000000
3,940	1.00000000000000	3,469	1.00000000000000	4,253	0.99999998569310	3,461	1.00000000000000
3,939	1.00000000000000	3,469	1.00000000000000	4,252	0.99999998559100	3,461	1.00000000000000
3,939	1.00000000000000	3,467	1.00000000000000	4,252	0.99999998512030	3,460	1.00000000000000
3,938	1.00000000000000	3,466	1.00000000000000	4,246	0.99999998705900	3,460	1.00000000000000
3,938	1.00000000000000	3,466	1.00000000000000	4,246	0.99999998624850	3,459	1.00000000000000
3,938	1.00000000000000	3,466	1.00000000000000	4,242	0.99999998686090	3,459	1.00000000000000
3,937	1.00000000000000	3,465	1.00000000000000	4,241	0.99999998746280	3,458	1.00000000000000
3,937	1.00000000000000	3,465	1.00000000000000	4,241	0.99999998559100	3,457	1.00000000000000
3,936	1.00000000000000	3,465	1.00000000000000	4,239	0.99999998644810	3,456	1.00000000000000
3,936	1.00000000000000	3,464	1.00000000000000	4,238	0.99999998766060	3,456	1.00000000000000
3,936	1.00000000000000	3,464	1.00000000000000	4,238	0.99999998635540	3,454	1.00000000000000
3,936	1.00000000000000	3,463	1.00000000000000	4,236	0.99999998696130	3,453	1.00000000000000
3,936	1.00000000000000	3,463	1.00000000000000	4,234	0.99999998725650	3,451	1.00000000000000
3,934	1.00000000000000	3,461	1.00000000000000	4,233	0.99999998757820	3,451	1.00000000000000
3,933	1.00000000000000	3,461	1.00000000000000	4,231	0.99999998718180	3,450	1.00000000000000
3,933	1.00000000000000	3,460	1.00000000000000	4,231	0.99999998590040	3,450	1.00000000000000
3,933	1.00000000000000	3,460	1.00000000000000	4,229	0.99999998728230	3,450	1.00000000000000
3,933	1.00000000000000	3,459	1.00000000000000	4,229	0.99999998697990	3,449	1.00000000000000
3,932	1.00000000000000	3,459	1.00000000000000	4,228	0.99999998812960	3,449	1.00000000000000
3,932	1.00000000000000	3,457	1.00000000000000	4,227	0.99999998738080	3,448	1.00000000000000
3,931	1.00000000000000	3,456	1.00000000000000	4,226	0.99999998747290	3,447	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,931	1.00000000000000	3,456	1.00000000000000	4,225	0.99999998850590	3,447	1.00000000000000
3,930	1.00000000000000	3,456	1.00000000000000	4,224	0.99999998777280	3,447	1.00000000000000
3,929	1.00000000000000	3,454	1.00000000000000	4,224	0.99999998841970	3,447	1.00000000000000
3,929	1.00000000000000	3,454	1.00000000000000	4,222	0.99999998869060	3,447	1.00000000000000
3,929	1.00000000000000	3,454	1.00000000000000	4,213	0.99999998935900	3,447	1.00000000000000
3,928	1.00000000000000	3,452	1.00000000000000	4,211	0.99999998953960	3,446	1.00000000000000
3,928	1.00000000000000	3,452	1.00000000000000	4,211	0.99999998903930	3,445	1.00000000000000
3,928	1.00000000000000	3,452	1.00000000000000	4,210	0.99999998812720	3,444	1.00000000000000
3,928	1.00000000000000	3,452	1.00000000000000	4,209	0.99999998977980	3,442	1.00000000000000
3,927	1.00000000000000	3,451	1.00000000000000	4,208	0.99999999069087	3,440	1.00000000000000
3,927	1.00000000000000	3,451	1.00000000000000	4,206	0.99999999002062	3,439	1.00000000000000
3,926	1.00000000000000	3,449	1.00000000000000	4,206	0.99999999062286	3,438	1.00000000000000
3,923	1.00000000000000	3,449	1.00000000000000	4,204	0.99999999001248	3,438	1.00000000000000
3,922	1.00000000000000	3,448	1.00000000000000	4,203	0.99999999018097	3,437	1.00000000000000
3,921	1.00000000000000	3,447	1.00000000000000	4,203	0.99999999025225	3,436	1.00000000000000
3,921	1.00000000000000	3,447	1.00000000000000	4,202	0.99999998841290	3,435	1.00000000000000
3,920	1.00000000000000	3,447	1.00000000000000	4,202	0.99999998993940	3,435	1.00000000000000
3,919	1.00000000000000	3,445	1.00000000000000	4,201	0.99999999105917	3,434	1.00000000000000
3,919	1.00000000000000	3,445	1.00000000000000	4,200	0.99999999040545	3,433	1.00000000000000
3,918	1.00000000000000	3,443	1.00000000000000	4,198	0.99999998919340	3,433	1.00000000000000
3,917	1.00000000000000	3,443	1.00000000000000	4,198	0.99999998902820	3,433	1.00000000000000
3,916	1.00000000000000	3,443	1.00000000000000	4,186	0.99999999106652	3,432	1.00000000000000
3,916	1.00000000000000	3,443	1.00000000000000	4,184	0.99999999155059	3,432	1.00000000000000
3,915	1.00000000000000	3,443	1.00000000000000	4,183	0.99999999107011	3,432	1.00000000000000
3,915	1.00000000000000	3,441	1.00000000000000	4,182	0.99999999224787	3,431	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,914	1.00000000000000	3,440	1.00000000000000	4,182	0.99999999039194	3,431	1.00000000000000
3,914	1.00000000000000	3,439	1.00000000000000	4,181	0.99999999127003	3,431	1.00000000000000
3,914	1.00000000000000	3,438	1.00000000000000	4,180	0.99999999200812	3,429	1.00000000000000
3,913	1.00000000000000	3,438	1.00000000000000	4,179	0.99999999141334	3,428	1.00000000000000
3,913	1.00000000000000	3,438	1.00000000000000	4,179	0.99999999255916	3,427	1.00000000000000
3,913	1.00000000000000	3,437	1.00000000000000	4,178	0.99999999194883	3,426	1.00000000000000
3,913	1.00000000000000	3,437	1.00000000000000	4,177	0.99999999180580	3,425	1.00000000000000
3,911	1.00000000000000	3,436	1.00000000000000	4,176	0.99999999207522	3,424	1.00000000000000
3,911	1.00000000000000	3,436	1.00000000000000	4,173	0.99999999181936	3,424	1.00000000000000
3,911	1.00000000000000	3,436	1.00000000000000	4,173	0.99999999213141	3,424	1.00000000000000
3,911	1.00000000000000	3,436	1.00000000000000	4,173	0.99999999278845	3,422	1.00000000000000
3,910	1.00000000000000	3,435	1.00000000000000	4,171	0.99999999225444	3,422	1.00000000000000
3,910	1.00000000000000	3,434	1.00000000000000	4,171	0.99999999238612	3,422	1.00000000000000
3,908	1.00000000000000	3,433	1.00000000000000	4,170	0.99999999238612	3,421	1.00000000000000
3,907	1.00000000000000	3,433	1.00000000000000	4,170	0.99999999279155	3,419	1.00000000000000
3,907	1.00000000000000	3,432	1.00000000000000	4,170	0.99999999078083	3,419	1.00000000000000
3,907	1.00000000000000	3,432	1.00000000000000	4,169	0.99999999126824	3,417	1.00000000000000
3,906	1.00000000000000	3,432	1.00000000000000	4,168	0.99999999250831	3,416	1.00000000000000
3,906	1.00000000000000	3,431	1.00000000000000	4,167	0.99999999261694	3,415	1.00000000000000
3,905	1.00000000000000	3,431	1.00000000000000	4,162	0.99999999360221	3,415	1.00000000000000
3,903	1.00000000000000	3,430	1.00000000000000	4,162	0.99999999267746	3,415	1.00000000000000
3,902	1.00000000000000	3,430	1.00000000000000	4,161	0.99999999302812	3,414	1.00000000000000
3,901	1.00000000000000	3,430	1.00000000000000	4,160	0.99999999308239	3,413	1.00000000000000
3,901	1.00000000000000	3,429	1.00000000000000	4,160	0.99999999238612	3,413	1.00000000000000
3,901	1.00000000000000	3,428	1.00000000000000	4,159	0.99999999290966	3,413	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,898	1.00000000000000	3,428	1.00000000000000	4,159	0.99999999244744	3,413	1.00000000000000
3,897	1.00000000000000	3,427	1.00000000000000	4,159	0.99999999174852	3,413	1.00000000000000
3,895	1.00000000000000	3,427	1.00000000000000	4,157	0.99999999324885	3,412	1.00000000000000
3,893	1.00000000000000	3,427	1.00000000000000	4,154	0.99999999380347	3,410	1.00000000000000
3,892	1.00000000000000	3,423	1.00000000000000	4,154	0.99999999297148	3,410	1.00000000000000
3,890	1.00000000000000	3,422	1.00000000000000	4,154	0.99999999297148	3,409	1.00000000000000
3,890	1.00000000000000	3,421	1.00000000000000	4,153	0.99999999340911	3,408	1.00000000000000
3,890	1.00000000000000	3,420	1.00000000000000	4,152	0.99999999225604	3,406	1.00000000000000
3,890	1.00000000000000	3,420	1.00000000000000	4,150	0.99999999350582	3,406	1.00000000000000
3,889	1.00000000000000	3,420	1.00000000000000	4,148	0.99999999361407	3,405	1.00000000000000
3,889	1.00000000000000	3,419	1.00000000000000	4,148	0.99999999308378	3,404	1.00000000000000
3,889	1.00000000000000	3,419	1.00000000000000	4,147	0.99999999405602	3,404	1.00000000000000
3,889	1.00000000000000	3,419	1.00000000000000	4,145	0.99999999437126	3,403	1.00000000000000
3,887	1.00000000000000	3,419	1.00000000000000	4,144	0.99999999410370	3,402	1.00000000000000
3,887	1.00000000000000	3,418	1.00000000000000	4,144	0.99999999279308	3,402	1.00000000000000
3,886	1.00000000000000	3,417	1.00000000000000	4,142	0.99999999454779	3,401	1.00000000000000
3,885	1.00000000000000	3,417	1.00000000000000	4,141	0.99999999390709	3,400	1.00000000000000
3,884	1.00000000000000	3,417	1.00000000000000	4,139	0.99999999415038	3,400	1.00000000000000
3,884	1.00000000000000	3,416	1.00000000000000	4,138	0.99999999334453	3,399	1.00000000000000
3,883	1.00000000000000	3,416	1.00000000000000	4,138	0.99999999381630	3,399	1.00000000000000
3,882	1.00000000000000	3,416	1.00000000000000	4,138	0.99999999386534	3,397	1.00000000000000
3,881	1.00000000000000	3,415	1.00000000000000	4,137	0.99999999438050	3,396	1.00000000000000
3,880	1.00000000000000	3,415	1.00000000000000	4,132	0.99999999496935	3,395	1.00000000000000
3,880	1.00000000000000	3,413	1.00000000000000	4,132	0.99999999410487	3,395	1.00000000000000
3,879	1.00000000000000	3,413	1.00000000000000	4,131	0.99999999325024	3,395	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,879	1.00000000000000	3,413	1.00000000000000	4,129	0.99999999472706	3,394	1.00000000000000
3,879	1.00000000000000	3,412	1.00000000000000	4,124	0.99999999508857	3,394	1.00000000000000
3,878	1.00000000000000	3,411	1.00000000000000	4,124	0.99999999451459	3,393	1.00000000000000
3,878	1.00000000000000	3,409	1.00000000000000	4,121	0.99999999480571	3,392	1.00000000000000
3,878	1.00000000000000	3,409	1.00000000000000	4,120	0.99999999464319	3,391	1.00000000000000
3,877	1.00000000000000	3,409	1.00000000000000	4,120	0.99999999423270	3,390	1.00000000000000
3,876	1.00000000000000	3,406	1.00000000000000	4,118	0.99999999543481	3,390	1.00000000000000
3,876	1.00000000000000	3,406	1.00000000000000	4,117	0.99999999400974	3,389	1.00000000000000
3,876	1.00000000000000	3,406	1.00000000000000	4,114	0.99999999437244	3,388	1.00000000000000
3,876	1.00000000000000	3,405	1.00000000000000	4,113	0.99999999550438	3,388	1.00000000000000
3,874	1.00000000000000	3,403	1.00000000000000	4,113	0.99999999524908	3,387	1.00000000000000
3,873	1.00000000000000	3,402	1.00000000000000	4,113	0.99999999415154	3,387	1.00000000000000
3,873	1.00000000000000	3,402	1.00000000000000	4,112	0.99999999532491	3,383	1.00000000000000
3,872	1.00000000000000	3,401	1.00000000000000	4,108	0.99999999513498	3,383	1.00000000000000
3,872	1.00000000000000	3,401	1.00000000000000	4,107	0.99999999558351	3,383	1.00000000000000
3,869	1.00000000000000	3,401	1.00000000000000	4,106	0.99999999585736	3,380	1.00000000000000
3,869	1.00000000000000	3,401	1.00000000000000	4,104	0.99999999546805	3,380	1.00000000000000
3,868	1.00000000000000	3,401	1.00000000000000	4,103	0.99999999564605	3,380	1.00000000000000
3,867	1.00000000000000	3,399	1.00000000000000	4,102	0.99999999592056	3,380	1.00000000000000
3,867	1.00000000000000	3,399	1.00000000000000	4,100	0.99999999568896	3,379	1.00000000000000
3,867	1.00000000000000	3,398	1.00000000000000	4,100	0.99999999611538	3,378	1.00000000000000
3,866	1.00000000000000	3,397	1.00000000000000	4,099	0.99999999547659	3,378	1.00000000000000
3,866	1.00000000000000	3,397	1.00000000000000	4,096	0.99999999608106	3,377	1.00000000000000
3,865	1.00000000000000	3,396	1.00000000000000	4,096	0.99999999582855	3,377	1.00000000000000
3,864	1.00000000000000	3,396	1.00000000000000	4,095	0.99999999612030	3,376	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,864	1.00000000000000	3,396	1.00000000000000	4,094	0.99999999618201	3,375	1.00000000000000
3,864	1.00000000000000	3,395	1.00000000000000	4,091	0.99999999615403	3,373	1.00000000000000
3,864	1.00000000000000	3,395	1.00000000000000	4,090	0.99999999601941	3,372	1.00000000000000
3,863	1.00000000000000	3,394	1.00000000000000	4,089	0.99999999568896	3,372	1.00000000000000
3,860	1.00000000000000	3,394	1.00000000000000	4,087	0.99999999612274	3,372	1.00000000000000
3,860	1.00000000000000	3,393	1.00000000000000	4,085	0.99999999596127	3,371	1.00000000000000
3,860	1.00000000000000	3,393	1.00000000000000	4,084	0.99999999602439	3,371	1.00000000000000
3,859	1.00000000000000	3,392	1.00000000000000	4,083	0.99999999463550	3,370	1.00000000000000
3,859	1.00000000000000	3,391	1.00000000000000	4,083	0.99999999602518	3,370	1.00000000000000
3,858	1.00000000000000	3,391	1.00000000000000	4,081	0.99999999618445	3,369	1.00000000000000
3,858	1.00000000000000	3,390	1.00000000000000	4,078	0.99999999642524	3,369	1.00000000000000
3,857	1.00000000000000	3,390	1.00000000000000	4,075	0.99999999636422	3,368	1.00000000000000
3,857	1.00000000000000	3,389	1.00000000000000	4,074	0.99999999636499	3,368	1.00000000000000
3,856	1.00000000000000	3,388	1.00000000000000	4,074	0.99999999630841	3,366	1.00000000000000
3,856	1.00000000000000	3,387	1.00000000000000	4,073	0.99999999672680	3,365	1.00000000000000
3,856	1.00000000000000	3,387	1.00000000000000	4,071	0.99999999639559	3,365	1.00000000000000
3,856	1.00000000000000	3,387	1.00000000000000	4,070	0.99999999686172	3,365	1.00000000000000
3,856	1.00000000000000	3,385	1.00000000000000	4,069	0.99999999665332	3,365	1.00000000000000
3,855	1.00000000000000	3,384	1.00000000000000	4,069	0.99999999592837	3,364	1.00000000000000
3,854	1.00000000000000	3,383	1.00000000000000	4,069	0.99999999667963	3,364	1.00000000000000
3,852	1.00000000000000	3,381	1.00000000000000	4,068	0.99999999667963	3,362	1.00000000000000
3,852	1.00000000000000	3,381	1.00000000000000	4,067	0.99999999664981	3,360	1.00000000000000
3,851	1.00000000000000	3,380	1.00000000000000	4,067	0.99999999670618	3,359	1.00000000000000
3,850	1.00000000000000	3,379	1.00000000000000	4,067	0.99999999667620	3,359	1.00000000000000
3,849	1.00000000000000	3,379	1.00000000000000	4,066	0.99999999624086	3,359	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,848	1.00000000000000	3,378	1.00000000000000	4,066	0.99999999673229	3,359	1.00000000000000
3,848	1.00000000000000	3,378	1.00000000000000	4,065	0.99999999664834	3,358	1.00000000000000
3,847	1.00000000000000	3,378	1.00000000000000	4,063	0.99999999689105	3,357	1.00000000000000
3,846	1.00000000000000	3,378	1.00000000000000	4,062	0.99999999683858	3,357	1.00000000000000
3,842	1.00000000000000	3,377	1.00000000000000	4,060	0.99999999683527	3,356	1.00000000000000
3,842	1.00000000000000	3,377	1.00000000000000	4,057	0.99999999678531	3,356	1.00000000000000
3,841	1.00000000000000	3,377	1.00000000000000	4,057	0.99999999706296	3,356	1.00000000000000
3,841	1.00000000000000	3,375	1.00000000000000	4,055	0.99999999722446	3,355	1.00000000000000
3,840	1.00000000000000	3,375	1.00000000000000	4,055	0.99999999698766	3,353	1.00000000000000
3,840	1.00000000000000	3,375	1.00000000000000	4,054	0.99999999700903	3,353	1.00000000000000
3,839	1.00000000000000	3,374	1.00000000000000	4,054	0.99999999678531	3,352	1.00000000000000
3,838	1.00000000000000	3,373	1.00000000000000	4,047	0.99999999717952	3,352	1.00000000000000
3,836	1.00000000000000	3,372	1.00000000000000	4,047	0.99999999715621	3,352	1.00000000000000
3,835	1.00000000000000	3,372	1.00000000000000	4,045	0.99999999727117	3,352	1.00000000000000
3,834	1.00000000000000	3,370	1.00000000000000	4,044	0.99999999727527	3,351	1.00000000000000
3,834	1.00000000000000	3,370	1.00000000000000	4,043	0.99999999729316	3,351	1.00000000000000
3,834	1.00000000000000	3,368	1.00000000000000	4,042	0.99999999746655	3,351	1.00000000000000
3,833	1.00000000000000	3,368	1.00000000000000	4,041	0.99999999740425	3,349	1.00000000000000
3,833	1.00000000000000	3,367	1.00000000000000	4,041	0.99999999675797	3,348	1.00000000000000
3,833	1.00000000000000	3,365	1.00000000000000	4,041	0.99999999718311	3,348	1.00000000000000
3,832	1.00000000000000	3,364	1.00000000000000	4,040	0.99999999734017	3,346	1.00000000000000
3,831	1.00000000000000	3,364	1.00000000000000	4,040	0.99999999736259	3,345	1.00000000000000
3,831	1.00000000000000	3,364	1.00000000000000	4,039	0.99999999735984	3,345	1.00000000000000
3,829	1.00000000000000	3,363	1.00000000000000	4,037	0.99999999624406	3,345	1.00000000000000
3,828	1.00000000000000	3,362	1.00000000000000	4,034	0.99999999768826	3,344	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,828	1.00000000000000	3,360	1.00000000000000	4,034	0.99999999734017	3,344	1.00000000000000
3,828	1.00000000000000	3,358	1.00000000000000	4,034	0.99999999751260	3,343	1.00000000000000
3,828	1.00000000000000	3,358	1.00000000000000	4,033	0.99999999751260	3,343	1.00000000000000
3,828	1.00000000000000	3,357	1.00000000000000	4,033	0.99999999734017	3,343	1.00000000000000
3,828	1.00000000000000	3,356	1.00000000000000	4,030	0.99999999763195	3,342	1.00000000000000
3,828	1.00000000000000	3,354	1.00000000000000	4,030	0.99999999757376	3,341	1.00000000000000
3,825	1.00000000000000	3,354	1.00000000000000	4,030	0.99999999701545	3,341	1.00000000000000
3,824	1.00000000000000	3,354	1.00000000000000	4,030	0.99999999751102	3,341	1.00000000000000
3,819	1.00000000000000	3,354	1.00000000000000	4,029	0.99999999747033	3,341	1.00000000000000
3,819	1.00000000000000	3,354	1.00000000000000	4,028	0.99999999765104	3,341	1.00000000000000
3,819	1.00000000000000	3,353	1.00000000000000	4,025	0.99999999729316	3,341	1.00000000000000
3,818	1.00000000000000	3,353	1.00000000000000	4,023	0.99999999778620	3,341	1.00000000000000
3,816	1.00000000000000	3,353	1.00000000000000	4,020	0.99999999678064	3,340	1.00000000000000
3,815	1.00000000000000	3,353	1.00000000000000	4,020	0.99999999763195	3,338	1.00000000000000
3,814	1.00000000000000	3,351	1.00000000000000	4,019	0.99999999757376	3,337	1.00000000000000
3,814	1.00000000000000	3,350	1.00000000000000	4,019	0.99999999780397	3,336	1.00000000000000
3,814	1.00000000000000	3,349	1.00000000000000	4,017	0.99999999795964	3,336	1.00000000000000
3,813	1.00000000000000	3,349	1.00000000000000	4,015	0.99999999773013	3,335	1.00000000000000
3,811	1.00000000000000	3,348	1.00000000000000	4,014	0.99999999785472	3,335	1.00000000000000
3,811	1.00000000000000	3,348	1.00000000000000	4,012	0.99999999780442	3,335	1.00000000000000
3,810	1.00000000000000	3,347	1.00000000000000	4,012	0.99999999760827	3,335	1.00000000000000
3,809	1.00000000000000	3,347	1.00000000000000	4,009	0.99999999797897	3,335	1.00000000000000
3,808	1.00000000000000	3,345	1.00000000000000	4,009	0.99999999802903	3,334	1.00000000000000
3,808	1.00000000000000	3,345	1.00000000000000	4,008	0.99999999785744	3,332	1.00000000000000
3,807	1.00000000000000	3,344	1.00000000000000	4,008	0.99999999797983	3,331	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,806	1.00000000000000	3,341	1.00000000000000	4,007	0.99999999790894	3,331	1.00000000000000
3,806	1.00000000000000	3,341	1.00000000000000	4,004	0.99999999822625	3,331	1.00000000000000
3,806	1.00000000000000	3,339	1.00000000000000	4,002	0.99999999807647	3,331	1.00000000000000
3,804	1.00000000000000	3,338	1.00000000000000	4,001	0.99999999805856	3,330	1.00000000000000
3,804	1.00000000000000	3,338	1.00000000000000	4,000	0.99999999807447	3,329	1.00000000000000
3,803	1.00000000000000	3,338	1.00000000000000	3,999	0.99999999823980	3,329	1.00000000000000
3,801	1.00000000000000	3,338	1.00000000000000	3,998	0.99999999805979	3,328	1.00000000000000
3,800	1.00000000000000	3,338	1.00000000000000	3,996	0.99999999817040	3,328	1.00000000000000
3,800	1.00000000000000	3,338	1.00000000000000	3,994	0.99999999778620	3,328	1.00000000000000
3,799	1.00000000000000	3,337	1.00000000000000	3,991	0.99999999819884	3,327	1.00000000000000
3,798	1.00000000000000	3,337	1.00000000000000	3,991	0.99999999837368	3,326	1.00000000000000
3,797	1.00000000000000	3,336	1.00000000000000	3,990	0.99999999813945	3,325	1.00000000000000
3,797	1.00000000000000	3,336	1.00000000000000	3,990	0.99999999824176	3,324	1.00000000000000
3,796	1.00000000000000	3,336	1.00000000000000	3,990	0.99999999826895	3,323	1.00000000000000
3,796	1.00000000000000	3,335	1.00000000000000	3,989	0.99999999830450	3,323	1.00000000000000
3,795	1.00000000000000	3,335	1.00000000000000	3,987	0.99999999830794	3,323	1.00000000000000
3,795	1.00000000000000	3,335	1.00000000000000	3,987	0.99999999821475	3,322	1.00000000000000
3,795	1.00000000000000	3,333	1.00000000000000	3,986	0.99999999851185	3,321	1.00000000000000
3,794	1.00000000000000	3,333	1.00000000000000	3,986	0.99999999815526	3,321	1.00000000000000
3,794	1.00000000000000	3,332	1.00000000000000	3,984	0.99999999818554	3,321	1.00000000000000
3,792	1.00000000000000	3,332	1.00000000000000	3,981	0.99999999844008	3,320	1.00000000000000
3,792	1.00000000000000	3,331	1.00000000000000	3,979	0.99999999841608	3,320	1.00000000000000
3,790	1.00000000000000	3,330	1.00000000000000	3,978	0.99999999844136	3,319	1.00000000000000
3,790	1.00000000000000	3,329	1.00000000000000	3,976	0.99999999818320	3,319	1.00000000000000
3,788	1.00000000000000	3,329	1.00000000000000	3,974	0.99999999774692	3,318	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,787	1.00000000000000	3,329	1.00000000000000	3,973	0.99999999840294	3,317	1.00000000000000
3,786	1.00000000000000	3,329	1.00000000000000	3,970	0.99999999852562	3,317	1.00000000000000
3,785	1.00000000000000	3,329	1.00000000000000	3,970	0.99999999844136	3,317	1.00000000000000
3,785	1.00000000000000	3,326	1.00000000000000	3,965	0.99999999852778	3,316	1.00000000000000
3,783	1.00000000000000	3,325	1.00000000000000	3,965	0.99999999861745	3,316	1.00000000000000
3,783	1.00000000000000	3,323	1.00000000000000	3,964	0.99999999856367	3,315	1.00000000000000
3,783	1.00000000000000	3,322	1.00000000000000	3,961	0.99999999876470	3,315	1.00000000000000
3,782	1.00000000000000	3,322	1.00000000000000	3,961	0.99999999834909	3,314	1.00000000000000
3,782	1.00000000000000	3,321	1.00000000000000	3,961	0.99999999871442	3,314	1.00000000000000
3,782	1.00000000000000	3,320	1.00000000000000	3,958	0.99999999872568	3,312	1.00000000000000
3,782	1.00000000000000	3,319	1.00000000000000	3,957	0.99999999867358	3,312	1.00000000000000
3,781	1.00000000000000	3,319	1.00000000000000	3,956	0.99999999839006	3,311	1.00000000000000
3,780	1.00000000000000	3,319	1.00000000000000	3,956	0.99999999867424	3,310	1.00000000000000
3,780	1.00000000000000	3,319	1.00000000000000	3,954	0.99999999868564	3,310	1.00000000000000
3,779	1.00000000000000	3,319	1.00000000000000	3,954	0.99999999868564	3,308	1.00000000000000
3,779	1.00000000000000	3,318	1.00000000000000	3,953	0.99999999863629	3,308	1.00000000000000
3,778	1.00000000000000	3,317	1.00000000000000	3,952	0.99999999871319	3,308	1.00000000000000
3,778	1.00000000000000	3,317	1.00000000000000	3,952	0.99999999880876	3,306	1.00000000000000
3,777	1.00000000000000	3,316	1.00000000000000	3,950	0.99999999892274	3,306	1.00000000000000
3,775	1.00000000000000	3,314	1.00000000000000	3,947	0.99999999888566	3,305	1.00000000000000
3,775	1.00000000000000	3,314	1.00000000000000	3,947	0.99999999818439	3,304	1.00000000000000
3,775	1.00000000000000	3,313	1.00000000000000	3,945	0.99999999891551	3,302	1.00000000000000
3,773	1.00000000000000	3,310	1.00000000000000	3,944	0.99999999883378	3,302	1.00000000000000
3,773	1.00000000000000	3,309	1.00000000000000	3,944	0.99999999897383	3,300	1.00000000000000
3,773	1.00000000000000	3,308	1.00000000000000	3,943	0.99999999894194	3,300	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,772	1.00000000000000	3,308	1.00000000000000	3,943	0.99999999907088	3,299	1.00000000000000
3,771	1.00000000000000	3,307	1.00000000000000	3,940	0.99999999873321	3,297	1.00000000000000
3,770	1.00000000000000	3,307	1.00000000000000	3,940	0.99999999910665	3,296	1.00000000000000
3,769	1.00000000000000	3,307	1.00000000000000	3,939	0.99999999890398	3,295	1.00000000000000
3,767	1.00000000000000	3,306	1.00000000000000	3,939	0.99999999886844	3,295	1.00000000000000
3,766	1.00000000000000	3,305	1.00000000000000	3,938	0.99999999903353	3,293	1.00000000000000
3,766	1.00000000000000	3,305	1.00000000000000	3,935	0.99999999900840	3,293	1.00000000000000
3,765	1.00000000000000	3,304	1.00000000000000	3,935	0.99999999892387	3,291	1.00000000000000
3,765	1.00000000000000	3,302	1.00000000000000	3,934	0.99999999878903	3,291	1.00000000000000
3,763	1.00000000000000	3,302	1.00000000000000	3,934	0.99999999912417	3,290	1.00000000000000
3,763	1.00000000000000	3,302	1.00000000000000	3,934	0.99999999897361	3,290	1.00000000000000
3,761	1.00000000000000	3,301	1.00000000000000	3,934	0.99999999921429	3,290	1.00000000000000
3,760	1.00000000000000	3,301	1.00000000000000	3,931	0.99999999912417	3,289	1.00000000000000
3,760	1.00000000000000	3,301	1.00000000000000	3,930	0.99999999912417	3,289	1.00000000000000
3,758	1.00000000000000	3,300	1.00000000000000	3,927	0.99999999919039	3,289	1.00000000000000
3,757	1.00000000000000	3,300	1.00000000000000	3,925	0.99999999923172	3,289	1.00000000000000
3,757	1.00000000000000	3,299	1.00000000000000	3,921	0.99999999938715	3,288	1.00000000000000
3,756	1.00000000000000	3,298	1.00000000000000	3,919	0.99999999892438	3,287	1.00000000000000
3,756	1.00000000000000	3,297	1.00000000000000	3,917	0.99999999938543	3,287	1.00000000000000
3,755	1.00000000000000	3,296	1.00000000000000	3,916	0.99999999909436	3,287	1.00000000000000
3,755	1.00000000000000	3,296	1.00000000000000	3,916	0.99999999923790	3,285	1.00000000000000
3,752	1.00000000000000	3,296	1.00000000000000	3,914	0.99999999942266	3,282	1.00000000000000
3,752	1.00000000000000	3,295	1.00000000000000	3,914	0.99999999936643	3,281	1.00000000000000
3,752	1.00000000000000	3,294	1.00000000000000	3,912	0.99999999927274	3,280	1.00000000000000
3,751	1.00000000000000	3,294	1.00000000000000	3,908	0.99999999953613	3,278	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,750	1.00000000000000	3,292	1.00000000000000	3,906	0.99999999944416	3,278	1.00000000000000
3,750	1.00000000000000	3,292	1.00000000000000	3,905	0.99999999939053	3,278	1.00000000000000
3,750	1.00000000000000	3,292	1.00000000000000	3,903	0.99999999880772	3,277	1.00000000000000
3,749	1.00000000000000	3,292	1.00000000000000	3,903	0.99999999941328	3,276	1.00000000000000
3,749	1.00000000000000	3,292	1.00000000000000	3,899	0.99999999944416	3,275	1.00000000000000
3,747	1.00000000000000	3,291	1.00000000000000	3,898	0.99999999925503	3,275	1.00000000000000
3,747	1.00000000000000	3,290	1.00000000000000	3,898	0.99999999945417	3,273	1.00000000000000
3,746	1.00000000000000	3,289	1.00000000000000	3,898	0.99999999945417	3,273	1.00000000000000
3,746	1.00000000000000	3,289	1.00000000000000	3,895	0.99999999957281	3,273	1.00000000000000
3,745	1.00000000000000	3,288	1.00000000000000	3,894	0.99999999964333	3,272	1.00000000000000
3,745	1.00000000000000	3,287	1.00000000000000	3,892	0.99999999961944	3,272	1.00000000000000
3,744	1.00000000000000	3,287	1.00000000000000	3,891	0.99999999950778	3,271	1.00000000000000
3,744	1.00000000000000	3,284	1.00000000000000	3,890	0.99999999957163	3,270	1.00000000000000
3,742	1.00000000000000	3,284	1.00000000000000	3,888	0.99999999966129	3,270	1.00000000000000
3,741	1.00000000000000	3,281	1.00000000000000	3,888	0.99999999962606	3,269	1.00000000000000
3,741	1.00000000000000	3,281	1.00000000000000	3,888	0.99999999957281	3,269	1.00000000000000
3,741	1.00000000000000	3,281	1.00000000000000	3,886	0.99999999960061	3,269	1.00000000000000
3,738	1.00000000000000	3,281	1.00000000000000	3,886	0.99999999961783	3,267	1.00000000000000
3,738	1.00000000000000	3,280	1.00000000000000	3,885	0.99999999982339	3,267	1.00000000000000
3,737	1.00000000000000	3,279	1.00000000000000	3,884	0.99999999961944	3,267	1.00000000000000
3,737	1.00000000000000	3,279	1.00000000000000	3,883	0.99999999952977	3,266	1.00000000000000
3,737	1.00000000000000	3,279	1.00000000000000	3,878	0.99999999971662	3,266	1.00000000000000
3,736	1.00000000000000	3,279	1.00000000000000	3,876	0.99999999952576	3,265	1.00000000000000
3,735	1.00000000000000	3,279	1.00000000000000	3,876	1.00000000000000	3,265	1.00000000000000
3,734	1.00000000000000	3,276	1.00000000000000	3,876	0.99999999972927	3,264	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,734	1.00000000000000	3,276	1.00000000000000	3,873	0.99999999976302	3,264	1.00000000000000
3,734	1.00000000000000	3,275	1.00000000000000	3,873	0.99999999985882	3,263	1.00000000000000
3,733	1.00000000000000	3,273	1.00000000000000	3,873	0.99999999981879	3,262	1.00000000000000
3,733	1.00000000000000	3,273	1.00000000000000	3,871	0.99999999956408	3,262	1.00000000000000
3,732	1.00000000000000	3,272	1.00000000000000	3,871	0.99999999965886	3,261	1.00000000000000
3,732	1.00000000000000	3,271	1.00000000000000	3,870	0.99999999981798	3,260	1.00000000000000
3,731	1.00000000000000	3,270	1.00000000000000	3,870	1.00000000000000	3,260	1.00000000000000
3,731	1.00000000000000	3,270	1.00000000000000	3,870	1.00000000000000	3,259	1.00000000000000
3,731	1.00000000000000	3,270	1.00000000000000	3,869	0.99999999936381	3,259	1.00000000000000
3,731	1.00000000000000	3,268	1.00000000000000	3,868	0.99999999979564	3,258	1.00000000000000
3,730	1.00000000000000	3,268	1.00000000000000	3,868	1.00000000000000	3,258	1.00000000000000
3,730	1.00000000000000	3,268	1.00000000000000	3,867	1.00000000000000	3,257	1.00000000000000
3,729	1.00000000000000	3,265	1.00000000000000	3,866	1.00000000000000	3,257	1.00000000000000
3,729	1.00000000000000	3,263	1.00000000000000	3,865	0.99999999940390	3,256	1.00000000000000
3,729	1.00000000000000	3,262	1.00000000000000	3,864	1.00000000000000	3,256	1.00000000000000
3,729	1.00000000000000	3,260	1.00000000000000	3,863	1.00000000000000	3,256	1.00000000000000
3,728	1.00000000000000	3,259	1.00000000000000	3,861	1.00000000000000	3,255	1.00000000000000
3,727	1.00000000000000	3,258	1.00000000000000	3,859	0.99999999972411	3,254	1.00000000000000
3,726	1.00000000000000	3,258	1.00000000000000	3,856	1.00000000000000	3,253	1.00000000000000
3,725	1.00000000000000	3,257	1.00000000000000	3,855	1.00000000000000	3,252	1.00000000000000
3,725	1.00000000000000	3,256	1.00000000000000	3,853	1.00000000000000	3,250	1.00000000000000
3,722	1.00000000000000	3,256	1.00000000000000	3,851	1.00000000000000	3,249	1.00000000000000
3,722	1.00000000000000	3,256	1.00000000000000	3,850	0.99999999959018	3,248	1.00000000000000
3,721	1.00000000000000	3,255	1.00000000000000	3,849	1.00000000000000	3,248	1.00000000000000
3,721	1.00000000000000	3,255	1.00000000000000	3,849	0.99999999981879	3,247	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,719	1.00000000000000	3,254	1.00000000000000	3,846	1.00000000000000	3,246	1.00000000000000
3,718	1.00000000000000	3,254	1.00000000000000	3,845	1.00000000000000	3,246	1.00000000000000
3,716	1.00000000000000	3,254	1.00000000000000	3,844	1.00000000000000	3,246	1.00000000000000
3,716	1.00000000000000	3,253	1.00000000000000	3,840	1.00000000000000	3,245	1.00000000000000
3,715	1.00000000000000	3,253	1.00000000000000	3,838	1.00000000000000	3,245	1.00000000000000
3,715	1.00000000000000	3,250	1.00000000000000	3,837	1.00000000000000	3,244	1.00000000000000
3,715	1.00000000000000	3,249	1.00000000000000	3,836	1.00000000000000	3,244	1.00000000000000
3,714	1.00000000000000	3,249	1.00000000000000	3,836	1.00000000000000	3,243	1.00000000000000
3,714	1.00000000000000	3,249	1.00000000000000	3,834	1.00000000000000	3,243	1.00000000000000
3,714	1.00000000000000	3,246	1.00000000000000	3,833	1.00000000000000	3,242	1.00000000000000
3,713	1.00000000000000	3,246	1.00000000000000	3,832	1.00000000000000	3,242	1.00000000000000
3,713	1.00000000000000	3,246	1.00000000000000	3,830	1.00000000000000	3,241	1.00000000000000
3,711	1.00000000000000	3,246	1.00000000000000	3,828	1.00000000000000	3,240	1.00000000000000
3,710	1.00000000000000	3,244	1.00000000000000	3,826	1.00000000000000	3,239	1.00000000000000
3,708	1.00000000000000	3,244	1.00000000000000	3,822	1.00000000000000	3,239	1.00000000000000
3,707	1.00000000000000	3,242	1.00000000000000	3,818	1.00000000000000	3,238	1.00000000000000
3,707	1.00000000000000	3,242	1.00000000000000	3,818	1.00000000000000	3,238	1.00000000000000
3,706	1.00000000000000	3,241	1.00000000000000	3,818	1.00000000000000	3,237	1.00000000000000
3,706	1.00000000000000	3,241	1.00000000000000	3,817	1.00000000000000	3,237	1.00000000000000
3,706	1.00000000000000	3,241	1.00000000000000	3,816	1.00000000000000	3,237	1.00000000000000
3,706	1.00000000000000	3,241	1.00000000000000	3,815	1.00000000000000	3,235	1.00000000000000
3,703	1.00000000000000	3,241	1.00000000000000	3,814	1.00000000000000	3,235	1.00000000000000
3,703	1.00000000000000	3,241	1.00000000000000	3,814	1.00000000000000	3,235	1.00000000000000
3,703	1.00000000000000	3,240	1.00000000000000	3,814	1.00000000000000	3,232	1.00000000000000
3,703	1.00000000000000	3,240	1.00000000000000	3,811	1.00000000000000	3,230	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,701	1.00000000000000	3,240	1.00000000000000	3,811	1.00000000000000	3,229	1.00000000000000
3,701	1.00000000000000	3,239	1.00000000000000	3,808	1.00000000000000	3,227	1.00000000000000
3,699	1.00000000000000	3,238	1.00000000000000	3,806	1.00000000000000	3,227	1.00000000000000
3,699	1.00000000000000	3,236	1.00000000000000	3,804	1.00000000000000	3,226	1.00000000000000
3,699	1.00000000000000	3,236	1.00000000000000	3,802	1.00000000000000	3,226	1.00000000000000
3,699	1.00000000000000	3,235	1.00000000000000	3,800	1.00000000000000	3,225	1.00000000000000
3,699	1.00000000000000	3,235	1.00000000000000	3,799	1.00000000000000	3,225	1.00000000000000
3,697	1.00000000000000	3,235	1.00000000000000	3,798	1.00000000000000	3,224	1.00000000000000
3,696	1.00000000000000	3,235	1.00000000000000	3,797	1.00000000000000	3,222	1.00000000000000
3,696	1.00000000000000	3,234	1.00000000000000	3,796	1.00000000000000	3,222	1.00000000000000
3,695	1.00000000000000	3,233	1.00000000000000	3,795	1.00000000000000	3,220	1.00000000000000
3,694	1.00000000000000	3,232	1.00000000000000	3,795	1.00000000000000	3,220	1.00000000000000
3,694	1.00000000000000	3,231	1.00000000000000	3,795	1.00000000000000	3,220	1.00000000000000
3,694	1.00000000000000	3,230	1.00000000000000	3,794	1.00000000000000	3,220	1.00000000000000
3,693	1.00000000000000	3,227	1.00000000000000	3,794	1.00000000000000	3,220	1.00000000000000
3,690	1.00000000000000	3,226	1.00000000000000	3,794	1.00000000000000	3,219	1.00000000000000
3,689	1.00000000000000	3,226	1.00000000000000	3,793	1.00000000000000	3,218	1.00000000000000
3,688	1.00000000000000	3,226	1.00000000000000	3,792	1.00000000000000	3,215	1.00000000000000
3,688	1.00000000000000	3,225	1.00000000000000	3,791	1.00000000000000	3,214	1.00000000000000
3,687	1.00000000000000	3,224	1.00000000000000	3,791	1.00000000000000	3,214	1.00000000000000
3,686	1.00000000000000	3,220	1.00000000000000	3,790	1.00000000000000	3,214	1.00000000000000
3,686	1.00000000000000	3,220	1.00000000000000	3,790	1.00000000000000	3,214	1.00000000000000
3,686	1.00000000000000	3,219	1.00000000000000	3,789	1.00000000000000	3,213	1.00000000000000
3,686	1.00000000000000	3,218	1.00000000000000	3,787	1.00000000000000	3,213	1.00000000000000
3,679	1.00000000000000	3,217	1.00000000000000	3,786	1.00000000000000	3,212	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,679	1.00000000000000	3,217	1.00000000000000	3,786	1.00000000000000	3,212	1.00000000000000
3,677	1.00000000000000	3,216	1.00000000000000	3,784	1.00000000000000	3,212	1.00000000000000
3,675	1.00000000000000	3,216	1.00000000000000	3,784	1.00000000000000	3,211	1.00000000000000
3,675	1.00000000000000	3,212	1.00000000000000	3,782	1.00000000000000	3,211	1.00000000000000
3,675	1.00000000000000	3,212	1.00000000000000	3,781	1.00000000000000	3,211	1.00000000000000
3,675	1.00000000000000	3,211	1.00000000000000	3,780	1.00000000000000	3,209	1.00000000000000
3,675	1.00000000000000	3,210	1.00000000000000	3,779	1.00000000000000	3,207	1.00000000000000
3,674	1.00000000000000	3,210	1.00000000000000	3,779	1.00000000000000	3,207	1.00000000000000
3,674	1.00000000000000	3,209	1.00000000000000	3,779	1.00000000000000	3,207	1.00000000000000
3,673	1.00000000000000	3,209	1.00000000000000	3,778	1.00000000000000	3,207	1.00000000000000
3,673	1.00000000000000	3,208	1.00000000000000	3,778	1.00000000000000	3,204	1.00000000000000
3,672	1.00000000000000	3,208	1.00000000000000	3,776	1.00000000000000	3,204	1.00000000000000
3,672	1.00000000000000	3,207	1.00000000000000	3,776	1.00000000000000	3,203	1.00000000000000
3,671	1.00000000000000	3,207	1.00000000000000	3,774	1.00000000000000	3,203	1.00000000000000
3,670	1.00000000000000	3,205	1.00000000000000	3,774	1.00000000000000	3,202	1.00000000000000
3,670	1.00000000000000	3,204	1.00000000000000	3,773	1.00000000000000	3,202	1.00000000000000
3,670	1.00000000000000	3,203	1.00000000000000	3,773	1.00000000000000	3,200	1.00000000000000
3,668	1.00000000000000	3,203	1.00000000000000	3,773	1.00000000000000	3,199	1.00000000000000
3,666	1.00000000000000	3,201	1.00000000000000	3,772	1.00000000000000	3,199	1.00000000000000
3,665	1.00000000000000	3,201	1.00000000000000	3,769	1.00000000000000	3,197	1.00000000000000
3,665	1.00000000000000	3,200	1.00000000000000	3,769	1.00000000000000	3,196	1.00000000000000
3,665	1.00000000000000	3,199	1.00000000000000	3,769	1.00000000000000	3,195	1.00000000000000
3,664	1.00000000000000	3,199	1.00000000000000	3,768	1.00000000000000	3,191	1.00000000000000
3,664	1.00000000000000	3,198	1.00000000000000	3,766	1.00000000000000	3,191	1.00000000000000
3,663	1.00000000000000	3,198	1.00000000000000	3,762	1.00000000000000	3,191	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,662	1.00000000000000	3,197	1.00000000000000	3,761	1.00000000000000	3,188	1.00000000000000
3,661	1.00000000000000	3,197	1.00000000000000	3,761	1.00000000000000	3,188	1.00000000000000
3,660	1.00000000000000	3,195	1.00000000000000	3,760	1.00000000000000	3,187	1.00000000000000
3,659	1.00000000000000	3,195	1.00000000000000	3,759	1.00000000000000	3,186	1.00000000000000
3,659	1.00000000000000	3,195	1.00000000000000	3,755	1.00000000000000	3,186	1.00000000000000
3,654	1.00000000000000	3,194	1.00000000000000	3,755	1.00000000000000	3,185	1.00000000000000
3,654	1.00000000000000	3,194	1.00000000000000	3,751	1.00000000000000	3,184	1.00000000000000
3,654	1.00000000000000	3,194	1.00000000000000	3,751	1.00000000000000	3,183	1.00000000000000
3,653	1.00000000000000	3,192	1.00000000000000	3,749	1.00000000000000	3,182	1.00000000000000
3,653	1.00000000000000	3,191	1.00000000000000	3,748	1.00000000000000	3,181	1.00000000000000
3,652	1.00000000000000	3,190	1.00000000000000	3,746	1.00000000000000	3,181	1.00000000000000
3,651	1.00000000000000	3,190	1.00000000000000	3,745	1.00000000000000	3,180	1.00000000000000
3,650	1.00000000000000	3,189	1.00000000000000	3,745	1.00000000000000	3,179	1.00000000000000
3,650	1.00000000000000	3,189	1.00000000000000	3,742	1.00000000000000	3,178	1.00000000000000
3,650	1.00000000000000	3,186	1.00000000000000	3,742	1.00000000000000	3,178	1.00000000000000
3,649	1.00000000000000	3,185	1.00000000000000	3,739	1.00000000000000	3,178	1.00000000000000
3,649	1.00000000000000	3,184	1.00000000000000	3,739	1.00000000000000	3,178	1.00000000000000
3,648	1.00000000000000	3,183	1.00000000000000	3,739	1.00000000000000	3,177	1.00000000000000
3,648	1.00000000000000	3,183	1.00000000000000	3,738	1.00000000000000	3,177	1.00000000000000
3,647	1.00000000000000	3,182	1.00000000000000	3,736	1.00000000000000	3,177	1.00000000000000
3,646	1.00000000000000	3,180	1.00000000000000	3,736	1.00000000000000	3,177	1.00000000000000
3,645	1.00000000000000	3,179	1.00000000000000	3,736	1.00000000000000	3,177	1.00000000000000
3,644	1.00000000000000	3,176	1.00000000000000	3,734	1.00000000000000	3,176	1.00000000000000
3,644	1.00000000000000	3,176	1.00000000000000	3,734	1.00000000000000	3,176	1.00000000000000
3,643	1.00000000000000	3,176	1.00000000000000	3,733	1.00000000000000	3,175	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,643	1.00000000000000	3,175	1.00000000000000	3,731	1.00000000000000	3,174	1.00000000000000
3,642	1.00000000000000	3,175	1.00000000000000	3,730	1.00000000000000	3,174	1.00000000000000
3,642	1.00000000000000	3,174	1.00000000000000	3,728	1.00000000000000	3,173	1.00000000000000
3,641	1.00000000000000	3,171	1.00000000000000	3,727	1.00000000000000	3,173	1.00000000000000
3,641	1.00000000000000	3,171	1.00000000000000	3,725	1.00000000000000	3,173	1.00000000000000
3,640	1.00000000000000	3,170	1.00000000000000	3,724	1.00000000000000	3,170	1.00000000000000
3,640	1.00000000000000	3,170	1.00000000000000	3,723	1.00000000000000	3,170	1.00000000000000
3,639	1.00000000000000	3,170	1.00000000000000	3,723	1.00000000000000	3,166	1.00000000000000
3,638	1.00000000000000	3,169	1.00000000000000	3,723	1.00000000000000	3,166	1.00000000000000
3,637	1.00000000000000	3,168	1.00000000000000	3,722	1.00000000000000	3,166	1.00000000000000
3,636	1.00000000000000	3,166	1.00000000000000	3,720	1.00000000000000	3,165	1.00000000000000
3,636	1.00000000000000	3,165	1.00000000000000	3,718	1.00000000000000	3,165	1.00000000000000
3,635	1.00000000000000	3,165	1.00000000000000	3,718	1.00000000000000	3,165	1.00000000000000
3,634	1.00000000000000	3,164	1.00000000000000	3,717	1.00000000000000	3,163	1.00000000000000
3,633	1.00000000000000	3,164	1.00000000000000	3,716	1.00000000000000	3,161	1.00000000000000
3,632	1.00000000000000	3,163	1.00000000000000	3,715	1.00000000000000	3,157	1.00000000000000
3,632	1.00000000000000	3,163	1.00000000000000	3,715	1.00000000000000	3,157	1.00000000000000
3,631	1.00000000000000	3,162	1.00000000000000	3,715	1.00000000000000	3,157	1.00000000000000
3,631	1.00000000000000	3,159	1.00000000000000	3,714	1.00000000000000	3,156	1.00000000000000
3,628	1.00000000000000	3,158	1.00000000000000	3,710	1.00000000000000	3,155	1.00000000000000
3,627	1.00000000000000	3,157	1.00000000000000	3,705	1.00000000000000	3,155	1.00000000000000
3,627	1.00000000000000	3,155	1.00000000000000	3,704	1.00000000000000	3,155	1.00000000000000
3,627	1.00000000000000	3,154	1.00000000000000	3,702	1.00000000000000	3,154	1.00000000000000
3,624	1.00000000000000	3,153	1.00000000000000	3,699	1.00000000000000	3,154	1.00000000000000
3,622	1.00000000000000	3,153	1.00000000000000	3,699	1.00000000000000	3,151	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,622	1.00000000000000	3,151	1.00000000000000	3,696	1.00000000000000	3,150	1.00000000000000
3,621	1.00000000000000	3,150	1.00000000000000	3,693	1.00000000000000	3,150	1.00000000000000
3,619	1.00000000000000	3,149	1.00000000000000	3,691	1.00000000000000	3,149	1.00000000000000
3,618	1.00000000000000	3,149	1.00000000000000	3,690	1.00000000000000	3,149	1.00000000000000
3,616	1.00000000000000	3,148	1.00000000000000	3,689	1.00000000000000	3,147	1.00000000000000
3,615	1.00000000000000	3,147	1.00000000000000	3,689	1.00000000000000	3,147	1.00000000000000
3,615	1.00000000000000	3,146	1.00000000000000	3,689	1.00000000000000	3,146	1.00000000000000
3,615	1.00000000000000	3,145	1.00000000000000	3,689	1.00000000000000	3,145	1.00000000000000
3,613	1.00000000000000	3,145	1.00000000000000	3,688	1.00000000000000	3,144	1.00000000000000
3,613	1.00000000000000	3,143	1.00000000000000	3,687	1.00000000000000	3,142	1.00000000000000
3,612	1.00000000000000	3,142	1.00000000000000	3,686	1.00000000000000	3,142	1.00000000000000
3,609	1.00000000000000	3,141	1.00000000000000	3,685	1.00000000000000	3,142	1.00000000000000
3,609	1.00000000000000	3,139	1.00000000000000	3,685	1.00000000000000	3,140	1.00000000000000
3,609	1.00000000000000	3,139	1.00000000000000	3,683	1.00000000000000	3,139	1.00000000000000
3,607	1.00000000000000	3,139	1.00000000000000	3,682	1.00000000000000	3,138	1.00000000000000
3,607	1.00000000000000	3,138	1.00000000000000	3,682	1.00000000000000	3,138	1.00000000000000
3,606	1.00000000000000	3,137	1.00000000000000	3,681	1.00000000000000	3,137	1.00000000000000
3,606	1.00000000000000	3,137	1.00000000000000	3,680	1.00000000000000	3,136	1.00000000000000
3,606	1.00000000000000	3,136	1.00000000000000	3,680	1.00000000000000	3,135	1.00000000000000
3,605	1.00000000000000	3,136	1.00000000000000	3,680	1.00000000000000	3,135	1.00000000000000
3,604	1.00000000000000	3,135	1.00000000000000	3,679	1.00000000000000	3,134	1.00000000000000
3,603	1.00000000000000	3,134	1.00000000000000	3,678	1.00000000000000	3,134	1.00000000000000
3,603	1.00000000000000	3,134	1.00000000000000	3,677	1.00000000000000	3,133	1.00000000000000
3,603	1.00000000000000	3,132	1.00000000000000	3,675	1.00000000000000	3,133	1.00000000000000
3,602	1.00000000000000	3,132	1.00000000000000	3,674	1.00000000000000	3,133	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,602	1.00000000000000	3,131	1.00000000000000	3,673	1.00000000000000	3,132	1.00000000000000
3,601	1.00000000000000	3,130	1.00000000000000	3,672	1.00000000000000	3,130	1.00000000000000
3,600	1.00000000000000	3,130	1.00000000000000	3,672	1.00000000000000	3,128	1.00000000000000
3,598	1.00000000000000	3,130	1.00000000000000	3,672	1.00000000000000	3,126	1.00000000000000
3,598	1.00000000000000	3,130	1.00000000000000	3,669	1.00000000000000	3,126	1.00000000000000
3,598	1.00000000000000	3,126	1.00000000000000	3,665	1.00000000000000	3,125	1.00000000000000
3,597	1.00000000000000	3,126	1.00000000000000	3,664	1.00000000000000	3,124	1.00000000000000
3,596	1.00000000000000	3,126	1.00000000000000	3,664	1.00000000000000	3,123	1.00000000000000
3,596	1.00000000000000	3,125	1.00000000000000	3,664	1.00000000000000	3,123	1.00000000000000
3,596	1.00000000000000	3,125	1.00000000000000	3,663	1.00000000000000	3,121	1.00000000000000
3,595	1.00000000000000	3,123	1.00000000000000	3,662	1.00000000000000	3,121	1.00000000000000
3,594	1.00000000000000	3,122	1.00000000000000	3,661	1.00000000000000	3,120	1.00000000000000
3,590	1.00000000000000	3,121	1.00000000000000	3,660	1.00000000000000	3,120	1.00000000000000
3,589	1.00000000000000	3,121	1.00000000000000	3,659	1.00000000000000	3,119	1.00000000000000
3,589	1.00000000000000	3,120	1.00000000000000	3,655	1.00000000000000	3,118	1.00000000000000
3,588	1.00000000000000	3,120	1.00000000000000	3,653	1.00000000000000	3,116	1.00000000000000
3,588	1.00000000000000	3,119	1.00000000000000	3,651	1.00000000000000	3,113	1.00000000000000
3,587	1.00000000000000	3,119	1.00000000000000	3,651	1.00000000000000	3,112	1.00000000000000
3,587	1.00000000000000	3,119	1.00000000000000	3,650	1.00000000000000	3,112	1.00000000000000
3,586	1.00000000000000	3,119	1.00000000000000	3,647	1.00000000000000	3,112	1.00000000000000
3,584	1.00000000000000	3,118	1.00000000000000	3,647	1.00000000000000	3,109	1.00000000000000
3,584	1.00000000000000	3,117	1.00000000000000	3,647	1.00000000000000	3,109	1.00000000000000
3,583	1.00000000000000	3,117	1.00000000000000	3,646	1.00000000000000	3,108	1.00000000000000
3,582	1.00000000000000	3,117	1.00000000000000	3,645	1.00000000000000	3,108	1.00000000000000
3,582	1.00000000000000	3,117	1.00000000000000	3,644	1.00000000000000	3,107	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,581	1.00000000000000	3,116	1.00000000000000	3,642	1.00000000000000	3,107	1.00000000000000
3,580	1.00000000000000	3,115	1.00000000000000	3,640	1.00000000000000	3,105	1.00000000000000
3,579	1.00000000000000	3,114	1.00000000000000	3,639	1.00000000000000	3,105	1.00000000000000
3,575	1.00000000000000	3,114	1.00000000000000	3,639	1.00000000000000	3,105	1.00000000000000
3,572	1.00000000000000	3,114	1.00000000000000	3,639	1.00000000000000	3,104	1.00000000000000
3,569	1.00000000000000	3,113	1.00000000000000	3,637	1.00000000000000	3,104	1.00000000000000
3,568	1.00000000000000	3,113	1.00000000000000	3,637	1.00000000000000	3,103	1.00000000000000
3,567	1.00000000000000	3,110	1.00000000000000	3,637	1.00000000000000	3,101	1.00000000000000
3,567	1.00000000000000	3,109	1.00000000000000	3,637	1.00000000000000	3,100	1.00000000000000
3,567	1.00000000000000	3,108	1.00000000000000	3,630	1.00000000000000	3,099	1.00000000000000
3,566	1.00000000000000	3,108	1.00000000000000	3,629	1.00000000000000	3,098	1.00000000000000
3,566	1.00000000000000	3,108	1.00000000000000	3,628	1.00000000000000	3,097	1.00000000000000
3,566	1.00000000000000	3,105	1.00000000000000	3,627	1.00000000000000	3,096	1.00000000000000
3,565	1.00000000000000	3,105	1.00000000000000	3,626	1.00000000000000	3,094	1.00000000000000
3,564	1.00000000000000	3,105	1.00000000000000	3,625	1.00000000000000	3,094	1.00000000000000
3,564	1.00000000000000	3,105	1.00000000000000	3,624	1.00000000000000	3,094	1.00000000000000
3,562	1.00000000000000	3,104	1.00000000000000	3,624	1.00000000000000	3,091	1.00000000000000
3,562	1.00000000000000	3,104	1.00000000000000	3,623	1.00000000000000	3,091	1.00000000000000
3,562	1.00000000000000	3,103	1.00000000000000	3,622	1.00000000000000	3,088	1.00000000000000
3,561	1.00000000000000	3,103	1.00000000000000	3,622	1.00000000000000	3,085	1.00000000000000
3,560	1.00000000000000	3,101	1.00000000000000	3,622	1.00000000000000	3,085	1.00000000000000
3,557	1.00000000000000	3,101	1.00000000000000	3,621	1.00000000000000	3,085	1.00000000000000
3,556	1.00000000000000	3,098	1.00000000000000	3,621	1.00000000000000	3,085	1.00000000000000
3,555	1.00000000000000	3,097	1.00000000000000	3,617	1.00000000000000	3,084	1.00000000000000
3,555	1.00000000000000	3,095	1.00000000000000	3,615	1.00000000000000	3,084	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,555	1.00000000000000	3,095	1.00000000000000	3,615	1.00000000000000	3,084	1.00000000000000
3,555	1.00000000000000	3,095	1.00000000000000	3,614	1.00000000000000	3,084	1.00000000000000
3,555	1.00000000000000	3,094	1.00000000000000	3,611	1.00000000000000	3,080	1.00000000000000
3,554	1.00000000000000	3,093	1.00000000000000	3,610	1.00000000000000	3,079	1.00000000000000
3,553	1.00000000000000	3,093	1.00000000000000	3,610	1.00000000000000	3,079	1.00000000000000
3,552	1.00000000000000	3,091	1.00000000000000	3,610	1.00000000000000	3,078	1.00000000000000
3,552	1.00000000000000	3,091	1.00000000000000	3,607	1.00000000000000	3,076	1.00000000000000
3,550	1.00000000000000	3,091	1.00000000000000	3,605	1.00000000000000	3,076	1.00000000000000
3,549	1.00000000000000	3,091	1.00000000000000	3,602	1.00000000000000	3,076	1.00000000000000
3,548	1.00000000000000	3,087	1.00000000000000	3,601	1.00000000000000	3,073	1.00000000000000
3,547	1.00000000000000	3,086	1.00000000000000	3,600	1.00000000000000	3,073	1.00000000000000
3,547	1.00000000000000	3,085	1.00000000000000	3,598	1.00000000000000	3,071	1.00000000000000
3,547	1.00000000000000	3,085	1.00000000000000	3,594	1.00000000000000	3,070	1.00000000000000
3,547	1.00000000000000	3,085	1.00000000000000	3,592	1.00000000000000	3,070	1.00000000000000
3,546	1.00000000000000	3,084	1.00000000000000	3,591	1.00000000000000	3,069	1.00000000000000
3,545	1.00000000000000	3,084	1.00000000000000	3,590	1.00000000000000	3,069	1.00000000000000
3,543	1.00000000000000	3,084	1.00000000000000	3,589	1.00000000000000	3,069	1.00000000000000
3,543	1.00000000000000	3,083	1.00000000000000	3,586	1.00000000000000	3,068	1.00000000000000
3,542	1.00000000000000	3,083	1.00000000000000	3,586	1.00000000000000	3,066	1.00000000000000
3,542	1.00000000000000	3,082	1.00000000000000	3,585	1.00000000000000	3,064	1.00000000000000
3,542	1.00000000000000	3,082	1.00000000000000	3,582	1.00000000000000	3,064	1.00000000000000
3,542	1.00000000000000	3,079	1.00000000000000	3,580	1.00000000000000	3,063	1.00000000000000
3,542	1.00000000000000	3,078	1.00000000000000	3,579	1.00000000000000	3,061	1.00000000000000
3,541	1.00000000000000	3,077	1.00000000000000	3,579	1.00000000000000	3,061	1.00000000000000
3,540	1.00000000000000	3,077	1.00000000000000	3,577	1.00000000000000	3,060	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,540	1.00000000000000	3,076	1.00000000000000	3,577	1.00000000000000	3,060	1.00000000000000
3,539	1.00000000000000	3,074	1.00000000000000	3,575	1.00000000000000	3,059	1.00000000000000
3,538	1.00000000000000	3,073	1.00000000000000	3,575	1.00000000000000	3,059	1.00000000000000
3,537	1.00000000000000	3,073	1.00000000000000	3,573	1.00000000000000	3,059	1.00000000000000
3,537	1.00000000000000	3,073	1.00000000000000	3,570	1.00000000000000	3,059	1.00000000000000
3,536	1.00000000000000	3,072	1.00000000000000	3,570	1.00000000000000	3,059	1.00000000000000
3,536	1.00000000000000	3,072	1.00000000000000	3,569	1.00000000000000	3,059	1.00000000000000
3,536	1.00000000000000	3,070	1.00000000000000	3,569	1.00000000000000	3,058	1.00000000000000
3,536	1.00000000000000	3,070	1.00000000000000	3,567	1.00000000000000	3,057	1.00000000000000
3,536	1.00000000000000	3,069	1.00000000000000	3,566	1.00000000000000	3,056	1.00000000000000
3,535	1.00000000000000	3,067	1.00000000000000	3,566	1.00000000000000	3,055	1.00000000000000
3,534	1.00000000000000	3,067	1.00000000000000	3,562	1.00000000000000	3,054	1.00000000000000
3,534	1.00000000000000	3,066	1.00000000000000	3,561	1.00000000000000	3,053	1.00000000000000
3,534	1.00000000000000	3,066	1.00000000000000	3,560	1.00000000000000	3,053	1.00000000000000
3,534	1.00000000000000	3,065	1.00000000000000	3,559	1.00000000000000	3,053	1.00000000000000
3,533	1.00000000000000	3,064	1.00000000000000	3,556	1.00000000000000	3,053	1.00000000000000
3,533	1.00000000000000	3,064	1.00000000000000	3,555	1.00000000000000	3,052	1.00000000000000
3,532	1.00000000000000	3,063	1.00000000000000	3,555	1.00000000000000	3,051	1.00000000000000
3,532	1.00000000000000	3,061	1.00000000000000	3,554	1.00000000000000	3,050	1.00000000000000
3,532	1.00000000000000	3,058	1.00000000000000	3,554	1.00000000000000	3,049	1.00000000000000
3,531	1.00000000000000	3,057	1.00000000000000	3,553	1.00000000000000	3,049	1.00000000000000
3,531	1.00000000000000	3,057	1.00000000000000	3,552	1.00000000000000	3,048	1.00000000000000
3,530	1.00000000000000	3,056	1.00000000000000	3,550	1.00000000000000	3,047	1.00000000000000
3,528	1.00000000000000	3,056	1.00000000000000	3,548	1.00000000000000	3,046	1.00000000000000
3,528	1.00000000000000	3,055	1.00000000000000	3,548	1.00000000000000	3,046	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,526	1.00000000000000	3,054	1.00000000000000	3,547	1.00000000000000	3,044	1.00000000000000
3,526	1.00000000000000	3,054	1.00000000000000	3,546	1.00000000000000	3,044	1.00000000000000
3,526	1.00000000000000	3,052	1.00000000000000	3,546	1.00000000000000	3,043	1.00000000000000
3,525	1.00000000000000	3,052	1.00000000000000	3,543	1.00000000000000	3,043	1.00000000000000
3,524	1.00000000000000	3,051	1.00000000000000	3,540	1.00000000000000	3,043	1.00000000000000
3,522	1.00000000000000	3,051	1.00000000000000	3,540	1.00000000000000	3,041	1.00000000000000
3,521	1.00000000000000	3,051	1.00000000000000	3,539	1.00000000000000	3,040	1.00000000000000
3,520	1.00000000000000	3,050	1.00000000000000	3,538	1.00000000000000	3,040	1.00000000000000
3,520	1.00000000000000	3,049	1.00000000000000	3,537	1.00000000000000	3,040	1.00000000000000
3,519	1.00000000000000	3,048	1.00000000000000	3,535	1.00000000000000	3,040	1.00000000000000
3,517	1.00000000000000	3,047	1.00000000000000	3,533	1.00000000000000	3,040	1.00000000000000
3,516	1.00000000000000	3,046	1.00000000000000	3,529	1.00000000000000	3,038	1.00000000000000
3,514	1.00000000000000	3,046	1.00000000000000	3,529	1.00000000000000	3,038	1.00000000000000
3,514	1.00000000000000	3,045	1.00000000000000	3,528	1.00000000000000	3,035	1.00000000000000
3,513	1.00000000000000	3,045	1.00000000000000	3,528	1.00000000000000	3,034	1.00000000000000
3,512	1.00000000000000	3,045	1.00000000000000	3,528	1.00000000000000	3,034	1.00000000000000
3,511	1.00000000000000	3,043	1.00000000000000	3,527	1.00000000000000	3,033	1.00000000000000
3,510	1.00000000000000	3,043	1.00000000000000	3,527	1.00000000000000	3,031	1.00000000000000
3,510	1.00000000000000	3,042	1.00000000000000	3,525	1.00000000000000	3,031	1.00000000000000
3,508	1.00000000000000	3,042	1.00000000000000	3,525	1.00000000000000	3,030	1.00000000000000
3,508	1.00000000000000	3,040	1.00000000000000	3,524	1.00000000000000	3,030	1.00000000000000
3,507	1.00000000000000	3,040	1.00000000000000	3,522	1.00000000000000	3,029	1.00000000000000
3,505	1.00000000000000	3,040	1.00000000000000	3,521	1.00000000000000	3,028	1.00000000000000
3,504	1.00000000000000	3,040	1.00000000000000	3,517	1.00000000000000	3,027	1.00000000000000
3,504	1.00000000000000	3,037	1.00000000000000	3,516	1.00000000000000	3,027	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,503	1.00000000000000	3,036	1.00000000000000	3,515	1.00000000000000	3,027	1.00000000000000
3,502	1.00000000000000	3,036	1.00000000000000	3,515	1.00000000000000	3,026	1.00000000000000
3,502	1.00000000000000	3,035	1.00000000000000	3,515	1.00000000000000	3,026	1.00000000000000
3,502	1.00000000000000	3,034	1.00000000000000	3,515	1.00000000000000	3,025	1.00000000000000
3,500	1.00000000000000	3,034	1.00000000000000	3,515	1.00000000000000	3,024	1.00000000000000
3,499	1.00000000000000	3,034	1.00000000000000	3,514	1.00000000000000	3,023	1.00000000000000
3,499	1.00000000000000	3,033	1.00000000000000	3,513	1.00000000000000	3,023	1.00000000000000
3,499	1.00000000000000	3,033	1.00000000000000	3,513	1.00000000000000	3,020	1.00000000000000
3,498	1.00000000000000	3,032	1.00000000000000	3,511	1.00000000000000	3,020	1.00000000000000
3,497	1.00000000000000	3,032	1.00000000000000	3,511	1.00000000000000	3,019	1.00000000000000
3,497	1.00000000000000	3,031	1.00000000000000	3,510	1.00000000000000	3,018	1.00000000000000
3,496	1.00000000000000	3,029	1.00000000000000	3,509	1.00000000000000	3,018	1.00000000000000
3,496	1.00000000000000	3,029	1.00000000000000	3,508	1.00000000000000	3,018	1.00000000000000
3,496	1.00000000000000	3,028	1.00000000000000	3,507	1.00000000000000	3,018	1.00000000000000
3,495	1.00000000000000	3,025	1.00000000000000	3,507	1.00000000000000	3,016	1.00000000000000
3,494	1.00000000000000	3,025	1.00000000000000	3,507	1.00000000000000	3,014	1.00000000000000
3,494	1.00000000000000	3,024	1.00000000000000	3,507	1.00000000000000	3,014	1.00000000000000
3,493	1.00000000000000	3,023	1.00000000000000	3,506	1.00000000000000	3,013	1.00000000000000
3,491	1.00000000000000	3,021	1.00000000000000	3,506	1.00000000000000	3,013	1.00000000000000
3,491	1.00000000000000	3,020	1.00000000000000	3,503	1.00000000000000	3,013	1.00000000000000
3,490	1.00000000000000	3,020	1.00000000000000	3,502	1.00000000000000	3,012	1.00000000000000
3,490	1.00000000000000	3,019	1.00000000000000	3,501	1.00000000000000	3,010	1.00000000000000
3,489	1.00000000000000	3,018	1.00000000000000	3,501	1.00000000000000	3,009	1.00000000000000
3,488	1.00000000000000	3,017	1.00000000000000	3,498	1.00000000000000	3,009	1.00000000000000
3,488	1.00000000000000	3,017	1.00000000000000	3,497	1.00000000000000	3,008	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,487	1.00000000000000	3,016	1.00000000000000	3,495	1.00000000000000	3,006	1.00000000000000
3,487	1.00000000000000	3,016	1.00000000000000	3,494	1.00000000000000	3,005	1.00000000000000
3,487	1.00000000000000	3,015	1.00000000000000	3,492	1.00000000000000	3,004	1.00000000000000
3,484	1.00000000000000	3,015	1.00000000000000	3,491	1.00000000000000	3,003	1.00000000000000
3,483	1.00000000000000	3,014	1.00000000000000	3,490	1.00000000000000	3,002	1.00000000000000
3,482	1.00000000000000	3,013	1.00000000000000	3,490	1.00000000000000	3,001	1.00000000000000
3,480	1.00000000000000	3,012	1.00000000000000	3,488	1.00000000000000	3,000	1.00000000000000
3,480	1.00000000000000	3,011	1.00000000000000	3,488	1.00000000000000	3,000	1.00000000000000
3,480	1.00000000000000	3,009	1.00000000000000	3,487	1.00000000000000	2,999	1.00000000000000
3,479	1.00000000000000	3,008	1.00000000000000	3,487	1.00000000000000	2,998	1.00000000000000
3,478	1.00000000000000	3,007	1.00000000000000	3,485	1.00000000000000	2,994	1.00000000000000
3,478	1.00000000000000	3,002	1.00000000000000	3,485	1.00000000000000	2,991	1.00000000000000
3,477	1.00000000000000	3,001	1.00000000000000	3,482	1.00000000000000	2,991	1.00000000000000
3,476	1.00000000000000	3,001	1.00000000000000	3,481	1.00000000000000	2,990	1.00000000000000
3,476	1.00000000000000	3,001	1.00000000000000	3,481	1.00000000000000	2,989	1.00000000000000
3,475	1.00000000000000	3,000	1.00000000000000	3,480	1.00000000000000	2,989	1.00000000000000
3,475	1.00000000000000	3,000	1.00000000000000	3,480	1.00000000000000	2,988	1.00000000000000
3,475	1.00000000000000	2,999	1.00000000000000	3,480	1.00000000000000	2,988	1.00000000000000
3,474	1.00000000000000	2,999	1.00000000000000	3,478	1.00000000000000	2,988	1.00000000000000
3,474	1.00000000000000	2,999	1.00000000000000	3,477	1.00000000000000	2,985	1.00000000000000
3,473	1.00000000000000	2,999	1.00000000000000	3,477	1.00000000000000	2,985	1.00000000000000
3,473	1.00000000000000	2,998	1.00000000000000	3,475	1.00000000000000	2,984	1.00000000000000
3,473	1.00000000000000	2,998	1.00000000000000	3,472	1.00000000000000	2,984	1.00000000000000
3,469	1.00000000000000	2,998	1.00000000000000	3,470	1.00000000000000	2,983	1.00000000000000
3,466	1.00000000000000	2,998	1.00000000000000	3,469	1.00000000000000	2,983	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,466	1.00000000000000	2,996	1.00000000000000	3,469	1.00000000000000	2,982	1.00000000000000
3,464	1.00000000000000	2,996	1.00000000000000	3,466	1.00000000000000	2,981	1.00000000000000
3,463	1.00000000000000	2,996	1.00000000000000	3,464	1.00000000000000	2,980	1.00000000000000
3,463	1.00000000000000	2,996	1.00000000000000	3,462	1.00000000000000	2,980	1.00000000000000
3,463	1.00000000000000	2,995	1.00000000000000	3,461	1.00000000000000	2,978	1.00000000000000
3,462	1.00000000000000	2,994	1.00000000000000	3,458	1.00000000000000	2,978	1.00000000000000
3,460	1.00000000000000	2,994	1.00000000000000	3,457	1.00000000000000	2,975	1.00000000000000
3,458	1.00000000000000	2,993	1.00000000000000	3,456	1.00000000000000	2,975	1.00000000000000
3,457	1.00000000000000	2,992	1.00000000000000	3,454	1.00000000000000	2,973	1.00000000000000
3,457	1.00000000000000	2,991	1.00000000000000	3,451	1.00000000000000	2,973	1.00000000000000
3,457	1.00000000000000	2,988	1.00000000000000	3,450	1.00000000000000	2,972	1.00000000000000
3,456	1.00000000000000	2,988	1.00000000000000	3,449	1.00000000000000	2,972	1.00000000000000
3,453	1.00000000000000	2,987	1.00000000000000	3,448	1.00000000000000	2,970	1.00000000000000
3,453	1.00000000000000	2,986	1.00000000000000	3,448	1.00000000000000	2,970	1.00000000000000
3,450	1.00000000000000	2,985	1.00000000000000	3,444	1.00000000000000	2,967	1.00000000000000
3,450	1.00000000000000	2,984	1.00000000000000	3,443	1.00000000000000	2,966	1.00000000000000
3,449	1.00000000000000	2,984	1.00000000000000	3,442	1.00000000000000	2,966	1.00000000000000
3,449	1.00000000000000	2,984	1.00000000000000	3,441	1.00000000000000	2,964	1.00000000000000
3,448	1.00000000000000	2,982	1.00000000000000	3,440	1.00000000000000	2,963	1.00000000000000
3,446	1.00000000000000	2,981	1.00000000000000	3,440	1.00000000000000	2,962	1.00000000000000
3,446	1.00000000000000	2,981	1.00000000000000	3,440	1.00000000000000	2,962	1.00000000000000
3,444	1.00000000000000	2,980	1.00000000000000	3,438	1.00000000000000	2,962	1.00000000000000
3,443	1.00000000000000	2,979	1.00000000000000	3,438	1.00000000000000	2,961	1.00000000000000
3,443	1.00000000000000	2,979	1.00000000000000	3,434	1.00000000000000	2,959	1.00000000000000
3,443	1.00000000000000	2,978	1.00000000000000	3,433	1.00000000000000	2,959	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,443	1.00000000000000	2,978	1.00000000000000	3,433	1.00000000000000	2,959	1.00000000000000
3,442	1.00000000000000	2,978	1.00000000000000	3,430	1.00000000000000	2,957	1.00000000000000
3,442	1.00000000000000	2,978	1.00000000000000	3,428	1.00000000000000	2,957	1.00000000000000
3,441	1.00000000000000	2,978	1.00000000000000	3,427	1.00000000000000	2,956	1.00000000000000
3,441	1.00000000000000	2,976	1.00000000000000	3,426	1.00000000000000	2,956	1.00000000000000
3,438	1.00000000000000	2,976	1.00000000000000	3,425	1.00000000000000	2,955	1.00000000000000
3,438	1.00000000000000	2,975	1.00000000000000	3,424	1.00000000000000	2,954	1.00000000000000
3,436	1.00000000000000	2,975	1.00000000000000	3,422	1.00000000000000	2,953	1.00000000000000
3,435	1.00000000000000	2,975	1.00000000000000	3,421	1.00000000000000	2,951	1.00000000000000
3,434	1.00000000000000	2,974	1.00000000000000	3,418	1.00000000000000	2,950	1.00000000000000
3,433	1.00000000000000	2,973	1.00000000000000	3,418	1.00000000000000	2,949	1.00000000000000
3,433	1.00000000000000	2,972	1.00000000000000	3,414	1.00000000000000	2,948	1.00000000000000
3,432	1.00000000000000	2,971	1.00000000000000	3,412	1.00000000000000	2,947	1.00000000000000
3,432	1.00000000000000	2,971	1.00000000000000	3,412	1.00000000000000	2,946	1.00000000000000
3,432	1.00000000000000	2,966	1.00000000000000	3,412	1.00000000000000	2,945	1.00000000000000
3,432	1.00000000000000	2,966	1.00000000000000	3,410	1.00000000000000	2,945	1.00000000000000
3,431	1.00000000000000	2,963	1.00000000000000	3,407	1.00000000000000	2,945	1.00000000000000
3,431	1.00000000000000	2,963	1.00000000000000	3,406	1.00000000000000	2,944	1.00000000000000
3,430	1.00000000000000	2,961	1.00000000000000	3,405	1.00000000000000	2,942	1.00000000000000
3,429	1.00000000000000	2,960	1.00000000000000	3,403	1.00000000000000	2,942	1.00000000000000
3,428	1.00000000000000	2,959	1.00000000000000	3,403	1.00000000000000	2,941	1.00000000000000
3,428	1.00000000000000	2,958	1.00000000000000	3,402	1.00000000000000	2,941	1.00000000000000
3,428	1.00000000000000	2,957	1.00000000000000	3,402	1.00000000000000	2,939	1.00000000000000
3,427	1.00000000000000	2,956	1.00000000000000	3,402	1.00000000000000	2,939	1.00000000000000
3,426	1.00000000000000	2,955	1.00000000000000	3,401	1.00000000000000	2,937	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,425	1.00000000000000	2,954	1.00000000000000	3,400	1.00000000000000	2,935	1.00000000000000
3,424	1.00000000000000	2,953	1.00000000000000	3,398	1.00000000000000	2,935	1.00000000000000
3,424	1.00000000000000	2,952	1.00000000000000	3,396	1.00000000000000	2,933	1.00000000000000
3,423	1.00000000000000	2,952	1.00000000000000	3,395	1.00000000000000	2,931	1.00000000000000
3,422	1.00000000000000	2,952	1.00000000000000	3,395	1.00000000000000	2,931	1.00000000000000
3,422	1.00000000000000	2,952	1.00000000000000	3,394	1.00000000000000	2,930	1.00000000000000
3,422	1.00000000000000	2,951	1.00000000000000	3,394	1.00000000000000	2,930	1.00000000000000
3,421	1.00000000000000	2,950	1.00000000000000	3,393	1.00000000000000	2,930	1.00000000000000
3,421	1.00000000000000	2,950	1.00000000000000	3,393	1.00000000000000	2,928	1.00000000000000
3,421	1.00000000000000	2,949	1.00000000000000	3,391	1.00000000000000	2,927	1.00000000000000
3,418	1.00000000000000	2,948	1.00000000000000	3,390	1.00000000000000	2,927	1.00000000000000
3,417	1.00000000000000	2,948	1.00000000000000	3,388	1.00000000000000	2,927	1.00000000000000
3,415	1.00000000000000	2,948	1.00000000000000	3,388	1.00000000000000	2,925	1.00000000000000
3,413	1.00000000000000	2,945	1.00000000000000	3,386	1.00000000000000	2,924	1.00000000000000
3,412	1.00000000000000	2,943	1.00000000000000	3,384	1.00000000000000	2,923	1.00000000000000
3,412	1.00000000000000	2,943	1.00000000000000	3,384	1.00000000000000	2,923	1.00000000000000
3,411	1.00000000000000	2,942	1.00000000000000	3,383	1.00000000000000	2,923	1.00000000000000
3,411	1.00000000000000	2,942	1.00000000000000	3,382	1.00000000000000	2,923	1.00000000000000
3,411	1.00000000000000	2,942	1.00000000000000	3,382	1.00000000000000	2,921	1.00000000000000
3,410	1.00000000000000	2,941	1.00000000000000	3,378	1.00000000000000	2,919	1.00000000000000
3,409	1.00000000000000	2,940	1.00000000000000	3,378	1.00000000000000	2,919	1.00000000000000
3,409	1.00000000000000	2,940	1.00000000000000	3,372	1.00000000000000	2,919	1.00000000000000
3,409	1.00000000000000	2,940	1.00000000000000	3,372	1.00000000000000	2,918	1.00000000000000
3,407	1.00000000000000	2,939	1.00000000000000	3,372	1.00000000000000	2,917	1.00000000000000
3,406	1.00000000000000	2,938	1.00000000000000	3,369	1.00000000000000	2,916	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,403	1.00000000000000	2,937	1.00000000000000	3,369	1.00000000000000	2,916	1.00000000000000
3,402	1.00000000000000	2,936	1.00000000000000	3,362	1.00000000000000	2,915	1.00000000000000
3,401	1.00000000000000	2,936	1.00000000000000	3,360	1.00000000000000	2,915	1.00000000000000
3,399	1.00000000000000	2,936	1.00000000000000	3,359	1.00000000000000	2,913	1.00000000000000
3,399	1.00000000000000	2,935	1.00000000000000	3,358	1.00000000000000	2,912	1.00000000000000
3,396	1.00000000000000	2,935	1.00000000000000	3,358	1.00000000000000	2,911	1.00000000000000
3,395	1.00000000000000	2,935	1.00000000000000	3,356	1.00000000000000	2,910	1.00000000000000
3,394	1.00000000000000	2,934	1.00000000000000	3,355	1.00000000000000	2,910	1.00000000000000
3,393	1.00000000000000	2,933	1.00000000000000	3,354	1.00000000000000	2,909	1.00000000000000
3,392	1.00000000000000	2,933	1.00000000000000	3,353	1.00000000000000	2,909	1.00000000000000
3,392	1.00000000000000	2,933	1.00000000000000	3,347	1.00000000000000	2,908	1.00000000000000
3,391	1.00000000000000	2,931	1.00000000000000	3,346	1.00000000000000	2,908	1.00000000000000
3,389	1.00000000000000	2,930	1.00000000000000	3,346	1.00000000000000	2,908	1.00000000000000
3,388	1.00000000000000	2,930	1.00000000000000	3,345	1.00000000000000	2,905	1.00000000000000
3,387	1.00000000000000	2,929	1.00000000000000	3,344	1.00000000000000	2,905	1.00000000000000
3,386	1.00000000000000	2,928	1.00000000000000	3,342	1.00000000000000	2,904	1.00000000000000
3,385	1.00000000000000	2,924	1.00000000000000	3,342	1.00000000000000	2,903	1.00000000000000
3,385	1.00000000000000	2,924	1.00000000000000	3,341	1.00000000000000	2,901	1.00000000000000
3,383	1.00000000000000	2,923	1.00000000000000	3,338	1.00000000000000	2,898	1.00000000000000
3,382	1.00000000000000	2,923	1.00000000000000	3,338	1.00000000000000	2,897	1.00000000000000
3,382	1.00000000000000	2,921	1.00000000000000	3,338	1.00000000000000	2,897	1.00000000000000
3,380	1.00000000000000	2,920	1.00000000000000	3,337	1.00000000000000	2,897	1.00000000000000
3,378	1.00000000000000	2,919	1.00000000000000	3,330	1.00000000000000	2,895	1.00000000000000
3,376	1.00000000000000	2,918	1.00000000000000	3,328	1.00000000000000	2,894	1.00000000000000
3,375	1.00000000000000	2,917	1.00000000000000	3,327	1.00000000000000	2,894	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,374	1.00000000000000	2,916	1.00000000000000	3,326	1.00000000000000	2,893	1.00000000000000
3,373	1.00000000000000	2,916	1.00000000000000	3,326	1.00000000000000	2,893	1.00000000000000
3,373	1.00000000000000	2,915	1.00000000000000	3,324	1.00000000000000	2,892	1.00000000000000
3,373	1.00000000000000	2,914	1.00000000000000	3,324	1.00000000000000	2,891	1.00000000000000
3,373	1.00000000000000	2,913	1.00000000000000	3,322	1.00000000000000	2,890	1.00000000000000
3,372	1.00000000000000	2,912	1.00000000000000	3,321	1.00000000000000	2,890	1.00000000000000
3,370	1.00000000000000	2,912	1.00000000000000	3,318	1.00000000000000	2,890	1.00000000000000
3,369	1.00000000000000	2,911	1.00000000000000	3,318	1.00000000000000	2,889	1.00000000000000
3,368	1.00000000000000	2,911	1.00000000000000	3,316	1.00000000000000	2,888	1.00000000000000
3,367	1.00000000000000	2,909	1.00000000000000	3,315	1.00000000000000	2,888	1.00000000000000
3,366	1.00000000000000	2,908	1.00000000000000	3,314	1.00000000000000	2,887	1.00000000000000
3,366	1.00000000000000	2,908	1.00000000000000	3,313	1.00000000000000	2,887	1.00000000000000
3,366	1.00000000000000	2,907	1.00000000000000	3,312	1.00000000000000	2,885	1.00000000000000
3,365	1.00000000000000	2,907	1.00000000000000	3,312	1.00000000000000	2,884	1.00000000000000
3,365	1.00000000000000	2,906	1.00000000000000	3,311	1.00000000000000	2,884	1.00000000000000
3,365	1.00000000000000	2,901	1.00000000000000	3,308	1.00000000000000	2,882	1.00000000000000
3,364	1.00000000000000	2,900	1.00000000000000	3,308	1.00000000000000	2,882	1.00000000000000
3,363	1.00000000000000	2,899	1.00000000000000	3,307	1.00000000000000	2,882	1.00000000000000
3,362	1.00000000000000	2,897	1.00000000000000	3,307	1.00000000000000	2,881	1.00000000000000
3,362	1.00000000000000	2,897	1.00000000000000	3,304	1.00000000000000	2,875	1.00000000000000
3,361	1.00000000000000	2,897	1.00000000000000	3,303	1.00000000000000	2,874	1.00000000000000
3,361	1.00000000000000	2,896	1.00000000000000	3,302	1.00000000000000	2,872	1.00000000000000
3,361	1.00000000000000	2,896	1.00000000000000	3,301	1.00000000000000	2,869	1.00000000000000
3,360	1.00000000000000	2,896	1.00000000000000	3,301	1.00000000000000	2,868	1.00000000000000
3,358	1.00000000000000	2,896	1.00000000000000	3,301	1.00000000000000	2,867	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,358	1.00000000000000	2,895	1.00000000000000	3,300	1.00000000000000	2,867	1.00000000000000
3,357	1.00000000000000	2,893	1.00000000000000	3,300	1.00000000000000	2,864	1.00000000000000
3,357	1.00000000000000	2,893	1.00000000000000	3,300	1.00000000000000	2,863	1.00000000000000
3,356	1.00000000000000	2,892	1.00000000000000	3,299	1.00000000000000	2,863	1.00000000000000
3,356	1.00000000000000	2,891	1.00000000000000	3,298	1.00000000000000	2,863	1.00000000000000
3,355	1.00000000000000	2,891	1.00000000000000	3,298	1.00000000000000	2,863	1.00000000000000
3,354	1.00000000000000	2,891	1.00000000000000	3,298	1.00000000000000	2,862	1.00000000000000
3,352	1.00000000000000	2,889	1.00000000000000	3,297	1.00000000000000	2,862	1.00000000000000
3,351	1.00000000000000	2,889	1.00000000000000	3,296	1.00000000000000	2,860	1.00000000000000
3,350	1.00000000000000	2,888	1.00000000000000	3,296	1.00000000000000	2,860	1.00000000000000
3,349	1.00000000000000	2,888	1.00000000000000	3,295	1.00000000000000	2,858	1.00000000000000
3,349	1.00000000000000	2,887	1.00000000000000	3,292	1.00000000000000	2,858	1.00000000000000
3,348	1.00000000000000	2,886	1.00000000000000	3,291	1.00000000000000	2,858	1.00000000000000
3,347	1.00000000000000	2,885	1.00000000000000	3,291	1.00000000000000	2,858	1.00000000000000
3,345	1.00000000000000	2,885	1.00000000000000	3,289	1.00000000000000	2,857	1.00000000000000
3,345	1.00000000000000	2,885	1.00000000000000	3,287	1.00000000000000	2,857	1.00000000000000
3,343	1.00000000000000	2,883	1.00000000000000	3,287	1.00000000000000	2,857	1.00000000000000
3,341	1.00000000000000	2,883	1.00000000000000	3,285	1.00000000000000	2,856	1.00000000000000
3,341	1.00000000000000	2,883	1.00000000000000	3,283	1.00000000000000	2,854	1.00000000000000
3,340	1.00000000000000	2,883	1.00000000000000	3,283	1.00000000000000	2,852	1.00000000000000
3,340	1.00000000000000	2,882	1.00000000000000	3,281	1.00000000000000	2,852	1.00000000000000
3,339	1.00000000000000	2,881	1.00000000000000	3,280	1.00000000000000	2,849	1.00000000000000
3,339	1.00000000000000	2,880	1.00000000000000	3,279	1.00000000000000	2,849	1.00000000000000
3,338	1.00000000000000	2,880	1.00000000000000	3,277	1.00000000000000	2,848	1.00000000000000
3,338	1.00000000000000	2,879	1.00000000000000	3,277	1.00000000000000	2,847	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,337	1.00000000000000	2,878	1.00000000000000	3,276	1.00000000000000	2,846	1.00000000000000
3,337	1.00000000000000	2,877	1.00000000000000	3,274	1.00000000000000	2,843	1.00000000000000
3,336	1.00000000000000	2,876	1.00000000000000	3,274	1.00000000000000	2,843	1.00000000000000
3,335	1.00000000000000	2,875	1.00000000000000	3,268	1.00000000000000	2,841	1.00000000000000
3,335	1.00000000000000	2,869	1.00000000000000	3,267	1.00000000000000	2,840	1.00000000000000
3,335	1.00000000000000	2,868	1.00000000000000	3,267	1.00000000000000	2,838	1.00000000000000
3,333	1.00000000000000	2,868	1.00000000000000	3,266	1.00000000000000	2,838	1.00000000000000
3,333	1.00000000000000	2,867	1.00000000000000	3,266	1.00000000000000	2,838	1.00000000000000
3,331	1.00000000000000	2,866	1.00000000000000	3,266	1.00000000000000	2,837	1.00000000000000
3,327	1.00000000000000	2,865	1.00000000000000	3,265	1.00000000000000	2,836	1.00000000000000
3,326	1.00000000000000	2,864	1.00000000000000	3,264	1.00000000000000	2,835	1.00000000000000
3,326	1.00000000000000	2,864	1.00000000000000	3,264	1.00000000000000	2,835	1.00000000000000
3,324	1.00000000000000	2,862	1.00000000000000	3,263	1.00000000000000	2,835	1.00000000000000
3,322	1.00000000000000	2,862	1.00000000000000	3,262	1.00000000000000	2,834	1.00000000000000
3,322	1.00000000000000	2,861	1.00000000000000	3,261	1.00000000000000	2,834	1.00000000000000
3,320	1.00000000000000	2,859	1.00000000000000	3,260	1.00000000000000	2,833	1.00000000000000
3,320	1.00000000000000	2,859	1.00000000000000	3,255	1.00000000000000	2,833	1.00000000000000
3,320	1.00000000000000	2,858	1.00000000000000	3,255	1.00000000000000	2,833	1.00000000000000
3,319	1.00000000000000	2,856	1.00000000000000	3,254	1.00000000000000	2,830	1.00000000000000
3,319	1.00000000000000	2,855	1.00000000000000	3,253	1.00000000000000	2,830	1.00000000000000
3,313	1.00000000000000	2,853	1.00000000000000	3,252	1.00000000000000	2,829	1.00000000000000
3,308	1.00000000000000	2,852	1.00000000000000	3,251	1.00000000000000	2,828	1.00000000000000
3,308	1.00000000000000	2,851	1.00000000000000	3,249	1.00000000000000	2,828	1.00000000000000
3,308	1.00000000000000	2,851	1.00000000000000	3,249	1.00000000000000	2,827	1.00000000000000
3,308	1.00000000000000	2,850	1.00000000000000	3,249	1.00000000000000	2,827	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,307	1.00000000000000	2,850	1.00000000000000	3,246	1.00000000000000	2,826	1.00000000000000
3,306	1.00000000000000	2,848	1.00000000000000	3,245	1.00000000000000	2,826	1.00000000000000
3,306	1.00000000000000	2,848	1.00000000000000	3,244	1.00000000000000	2,824	1.00000000000000
3,304	1.00000000000000	2,848	1.00000000000000	3,244	1.00000000000000	2,823	1.00000000000000
3,303	1.00000000000000	2,848	1.00000000000000	3,242	1.00000000000000	2,822	1.00000000000000
3,302	1.00000000000000	2,847	1.00000000000000	3,242	1.00000000000000	2,821	1.00000000000000
3,302	1.00000000000000	2,847	1.00000000000000	3,242	1.00000000000000	2,821	1.00000000000000
3,300	1.00000000000000	2,846	1.00000000000000	3,242	1.00000000000000	2,819	1.00000000000000
3,300	1.00000000000000	2,846	1.00000000000000	3,240	1.00000000000000	2,818	1.00000000000000
3,299	1.00000000000000	2,846	1.00000000000000	3,239	1.00000000000000	2,817	1.00000000000000
3,299	1.00000000000000	2,845	1.00000000000000	3,236	1.00000000000000	2,815	1.00000000000000
3,298	1.00000000000000	2,845	1.00000000000000	3,235	1.00000000000000	2,814	1.00000000000000
3,298	1.00000000000000	2,844	1.00000000000000	3,233	1.00000000000000	2,813	1.00000000000000
3,295	1.00000000000000	2,843	1.00000000000000	3,230	1.00000000000000	2,812	1.00000000000000
3,295	1.00000000000000	2,843	1.00000000000000	3,229	1.00000000000000	2,811	1.00000000000000
3,294	1.00000000000000	2,840	1.00000000000000	3,229	1.00000000000000	2,811	1.00000000000000
3,292	1.00000000000000	2,840	1.00000000000000	3,228	1.00000000000000	2,811	1.00000000000000
3,290	1.00000000000000	2,839	1.00000000000000	3,226	1.00000000000000	2,809	1.00000000000000
3,289	1.00000000000000	2,838	1.00000000000000	3,223	1.00000000000000	2,809	1.00000000000000
3,287	1.00000000000000	2,838	1.00000000000000	3,222	1.00000000000000	2,808	1.00000000000000
3,287	1.00000000000000	2,838	1.00000000000000	3,221	1.00000000000000	2,808	1.00000000000000
3,286	1.00000000000000	2,837	1.00000000000000	3,220	1.00000000000000	2,808	1.00000000000000
3,286	1.00000000000000	2,837	1.00000000000000	3,213	1.00000000000000	2,806	1.00000000000000
3,284	1.00000000000000	2,837	1.00000000000000	3,211	1.00000000000000	2,804	1.00000000000000
3,284	1.00000000000000	2,836	1.00000000000000	3,210	1.00000000000000	2,803	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,281	1.00000000000000	2,835	1.00000000000000	3,209	1.00000000000000	2,802	1.00000000000000
3,281	1.00000000000000	2,833	1.00000000000000	3,207	1.00000000000000	2,802	1.00000000000000
3,279	1.00000000000000	2,833	1.00000000000000	3,203	1.00000000000000	2,801	1.00000000000000
3,279	1.00000000000000	2,833	1.00000000000000	3,203	1.00000000000000	2,800	1.00000000000000
3,279	1.00000000000000	2,833	1.00000000000000	3,201	1.00000000000000	2,799	1.00000000000000
3,278	1.00000000000000	2,832	1.00000000000000	3,201	1.00000000000000	2,799	1.00000000000000
3,278	1.00000000000000	2,831	1.00000000000000	3,200	1.00000000000000	2,799	1.00000000000000
3,278	1.00000000000000	2,830	1.00000000000000	3,200	1.00000000000000	2,799	1.00000000000000
3,277	1.00000000000000	2,829	1.00000000000000	3,198	1.00000000000000	2,799	1.00000000000000
3,276	1.00000000000000	2,828	1.00000000000000	3,197	1.00000000000000	2,799	1.00000000000000
3,275	1.00000000000000	2,828	1.00000000000000	3,197	1.00000000000000	2,798	1.00000000000000
3,275	1.00000000000000	2,828	1.00000000000000	3,194	1.00000000000000	2,798	1.00000000000000
3,274	1.00000000000000	2,826	1.00000000000000	3,193	1.00000000000000	2,796	1.00000000000000
3,274	1.00000000000000	2,826	1.00000000000000	3,193	1.00000000000000	2,796	1.00000000000000
3,272	1.00000000000000	2,826	1.00000000000000	3,193	1.00000000000000	2,795	1.00000000000000
3,271	1.00000000000000	2,823	1.00000000000000	3,191	1.00000000000000	2,794	1.00000000000000
3,267	1.00000000000000	2,822	1.00000000000000	3,190	1.00000000000000	2,792	1.00000000000000
3,265	1.00000000000000	2,820	1.00000000000000	3,189	1.00000000000000	2,792	1.00000000000000
3,265	1.00000000000000	2,818	1.00000000000000	3,188	1.00000000000000	2,790	1.00000000000000
3,264	1.00000000000000	2,818	1.00000000000000	3,182	1.00000000000000	2,789	1.00000000000000
3,263	1.00000000000000	2,818	1.00000000000000	3,180	1.00000000000000	2,786	1.00000000000000
3,263	1.00000000000000	2,817	1.00000000000000	3,178	1.00000000000000	2,783	1.00000000000000
3,263	1.00000000000000	2,817	1.00000000000000	3,176	1.00000000000000	2,781	1.00000000000000
3,262	1.00000000000000	2,816	1.00000000000000	3,173	1.00000000000000	2,781	1.00000000000000
3,262	1.00000000000000	2,816	1.00000000000000	3,173	1.00000000000000	2,781	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,260	1.00000000000000	2,816	1.00000000000000	3,170	1.00000000000000	2,781	1.00000000000000
3,257	1.00000000000000	2,816	1.00000000000000	3,169	1.00000000000000	2,780	1.00000000000000
3,256	1.00000000000000	2,815	1.00000000000000	3,168	1.00000000000000	2,779	1.00000000000000
3,255	1.00000000000000	2,814	1.00000000000000	3,167	1.00000000000000	2,778	1.00000000000000
3,255	1.00000000000000	2,812	1.00000000000000	3,165	1.00000000000000	2,777	1.00000000000000
3,255	1.00000000000000	2,811	1.00000000000000	3,163	1.00000000000000	2,777	1.00000000000000
3,255	1.00000000000000	2,811	1.00000000000000	3,162	1.00000000000000	2,776	1.00000000000000
3,250	1.00000000000000	2,809	1.00000000000000	3,161	1.00000000000000	2,774	1.00000000000000
3,247	1.00000000000000	2,809	1.00000000000000	3,160	1.00000000000000	2,774	1.00000000000000
3,247	1.00000000000000	2,807	1.00000000000000	3,160	1.00000000000000	2,774	1.00000000000000
3,246	1.00000000000000	2,807	1.00000000000000	3,160	1.00000000000000	2,772	1.00000000000000
3,246	1.00000000000000	2,807	1.00000000000000	3,156	1.00000000000000	2,771	1.00000000000000
3,245	1.00000000000000	2,806	1.00000000000000	3,155	1.00000000000000	2,771	1.00000000000000
3,243	1.00000000000000	2,806	1.00000000000000	3,154	1.00000000000000	2,770	1.00000000000000
3,243	1.00000000000000	2,805	1.00000000000000	3,154	1.00000000000000	2,768	1.00000000000000
3,242	1.00000000000000	2,805	1.00000000000000	3,153	1.00000000000000	2,767	1.00000000000000
3,242	1.00000000000000	2,805	1.00000000000000	3,151	1.00000000000000	2,766	1.00000000000000
3,242	1.00000000000000	2,804	1.00000000000000	3,148	1.00000000000000	2,764	1.00000000000000
3,241	1.00000000000000	2,804	1.00000000000000	3,146	1.00000000000000	2,764	1.00000000000000
3,238	1.00000000000000	2,804	1.00000000000000	3,145	1.00000000000000	2,763	1.00000000000000
3,235	1.00000000000000	2,803	1.00000000000000	3,145	1.00000000000000	2,763	1.00000000000000
3,234	1.00000000000000	2,802	1.00000000000000	3,142	1.00000000000000	2,762	1.00000000000000
3,232	1.00000000000000	2,800	1.00000000000000	3,142	1.00000000000000	2,762	1.00000000000000
3,232	1.00000000000000	2,799	1.00000000000000	3,139	1.00000000000000	2,762	1.00000000000000
3,232	1.00000000000000	2,799	1.00000000000000	3,139	1.00000000000000	2,761	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,231	1.00000000000000	2,798	1.00000000000000	3,137	1.00000000000000	2,761	1.00000000000000
3,231	1.00000000000000	2,797	1.00000000000000	3,137	1.00000000000000	2,758	1.00000000000000
3,227	1.00000000000000	2,797	1.00000000000000	3,136	1.00000000000000	2,757	1.00000000000000
3,227	1.00000000000000	2,796	1.00000000000000	3,135	1.00000000000000	2,750	1.00000000000000
3,226	1.00000000000000	2,796	1.00000000000000	3,131	1.00000000000000	2,749	1.00000000000000
3,224	1.00000000000000	2,796	1.00000000000000	3,131	1.00000000000000	2,746	1.00000000000000
3,223	1.00000000000000	2,795	1.00000000000000	3,130	1.00000000000000	2,745	1.00000000000000
3,223	1.00000000000000	2,793	1.00000000000000	3,128	1.00000000000000	2,744	1.00000000000000
3,222	1.00000000000000	2,793	1.00000000000000	3,128	1.00000000000000	2,743	1.00000000000000
3,219	1.00000000000000	2,792	1.00000000000000	3,127	1.00000000000000	2,742	1.00000000000000
3,218	1.00000000000000	2,792	1.00000000000000	3,126	1.00000000000000	2,742	1.00000000000000
3,217	1.00000000000000	2,790	1.00000000000000	3,124	1.00000000000000	2,741	1.00000000000000
3,216	1.00000000000000	2,787	1.00000000000000	3,122	1.00000000000000	2,741	1.00000000000000
3,215	1.00000000000000	2,786	1.00000000000000	3,122	1.00000000000000	2,738	1.00000000000000
3,214	1.00000000000000	2,786	1.00000000000000	3,122	1.00000000000000	2,735	1.00000000000000
3,213	1.00000000000000	2,785	1.00000000000000	3,121	1.00000000000000	2,734	1.00000000000000
3,209	1.00000000000000	2,785	1.00000000000000	3,121	1.00000000000000	2,733	1.00000000000000
3,206	1.00000000000000	2,785	1.00000000000000	3,117	1.00000000000000	2,733	1.00000000000000
3,205	1.00000000000000	2,784	0.99997792550000	3,116	1.00000000000000	2,733	1.00000000000000
3,205	1.00000000000000	2,783	1.00000000000000	3,115	1.00000000000000	2,732	1.00000000000000
3,204	1.00000000000000	2,782	1.00000000000000	3,114	1.00000000000000	2,730	1.00000000000000
3,203	1.00000000000000	2,780	1.00000000000000	3,114	1.00000000000000	2,730	1.00000000000000
3,203	1.00000000000000	2,779	1.00000000000000	3,111	1.00000000000000	2,726	1.00000000000000
3,202	1.00000000000000	2,779	1.00000000000000	3,108	1.00000000000000	2,725	1.00000000000000
3,200	1.00000000000000	2,779	1.00000000000000	3,107	1.00000000000000	2,723	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,199	1.00000000000000	2,779	1.00000000000000	3,106	1.00000000000000	2,723	1.00000000000000
3,196	1.00000000000000	2,778	1.00000000000000	3,106	1.00000000000000	2,722	1.00000000000000
3,195	1.00000000000000	2,778	1.00000000000000	3,104	1.00000000000000	2,720	1.00000000000000
3,195	1.00000000000000	2,778	1.00000000000000	3,104	1.00000000000000	2,720	1.00000000000000
3,194	1.00000000000000	2,776	1.00000000000000	3,103	1.00000000000000	2,719	1.00000000000000
3,193	1.00000000000000	2,775	1.00000000000000	3,102	1.00000000000000	2,719	1.00000000000000
3,193	1.00000000000000	2,774	1.00000000000000	3,101	1.00000000000000	2,718	1.00000000000000
3,193	1.00000000000000	2,774	1.00000000000000	3,098	1.00000000000000	2,715	1.00000000000000
3,193	1.00000000000000	2,773	1.00000000000000	3,098	1.00000000000000	2,713	1.00000000000000
3,188	1.00000000000000	2,772	1.00000000000000	3,096	1.00000000000000	2,711	1.00000000000000
3,186	1.00000000000000	2,772	1.00000000000000	3,095	1.00000000000000	2,710	1.00000000000000
3,184	1.00000000000000	2,765	1.00000000000000	3,095	1.00000000000000	2,708	1.00000000000000
3,183	1.00000000000000	2,765	1.00000000000000	3,094	1.00000000000000	2,708	1.00000000000000
3,181	1.00000000000000	2,764	1.00000000000000	3,093	1.00000000000000	2,707	1.00000000000000
3,181	1.00000000000000	2,764	1.00000000000000	3,088	1.00000000000000	2,707	1.00000000000000
3,181	1.00000000000000	2,763	1.00000000000000	3,084	1.00000000000000	2,706	1.00000000000000
3,179	1.00000000000000	2,761	1.00000000000000	3,084	1.00000000000000	2,704	1.00000000000000
3,177	1.00000000000000	2,761	1.00000000000000	3,083	1.00000000000000	2,704	1.00000000000000
3,177	1.00000000000000	2,761	1.00000000000000	3,083	1.00000000000000	2,704	1.00000000000000
3,176	1.00000000000000	2,760	1.00000000000000	3,078	1.00000000000000	2,702	1.00000000000000
3,174	1.00000000000000	2,757	1.00000000000000	3,077	1.00000000000000	2,700	1.00000000000000
3,173	1.00000000000000	2,756	1.00000000000000	3,076	1.00000000000000	2,699	1.00000000000000
3,171	1.00000000000000	2,756	1.00000000000000	3,075	1.00000000000000	2,699	1.00000000000000
3,169	1.00000000000000	2,754	1.00000000000000	3,075	1.00000000000000	2,699	1.00000000000000
3,169	1.00000000000000	2,752	1.00000000000000	3,075	1.00000000000000	2,697	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,169	1.00000000000000	2,751	1.00000000000000	3,074	1.00000000000000	2,695	1.00000000000000
3,166	1.00000000000000	2,751	1.00000000000000	3,074	1.00000000000000	2,694	1.00000000000000
3,165	1.00000000000000	2,749	1.00000000000000	3,074	1.00000000000000	2,693	1.00000000000000
3,164	1.00000000000000	2,748	1.00000000000000	3,072	1.00000000000000	2,693	1.00000000000000
3,163	1.00000000000000	2,748	1.00000000000000	3,069	1.00000000000000	2,692	1.00000000000000
3,163	1.00000000000000	2,748	1.00000000000000	3,068	1.00000000000000	2,689	1.00000000000000
3,160	1.00000000000000	2,746	1.00000000000000	3,068	1.00000000000000	2,688	1.00000000000000
3,158	1.00000000000000	2,745	1.00000000000000	3,068	1.00000000000000	2,688	1.00000000000000
3,156	1.00000000000000	2,745	1.00000000000000	3,067	1.00000000000000	2,687	1.00000000000000
3,155	1.00000000000000	2,743	1.00000000000000	3,066	1.00000000000000	2,685	1.00000000000000
3,154	1.00000000000000	2,743	1.00000000000000	3,065	1.00000000000000	2,685	1.00000000000000
3,152	1.00000000000000	2,742	1.00000000000000	3,064	1.00000000000000	2,684	1.00000000000000
3,151	1.00000000000000	2,741	1.00000000000000	3,063	1.00000000000000	2,682	1.00000000000000
3,151	1.00000000000000	2,741	1.00000000000000	3,062	1.00000000000000	2,682	1.00000000000000
3,149	1.00000000000000	2,740	1.00000000000000	3,061	1.00000000000000	2,681	1.00000000000000
3,148	1.00000000000000	2,737	1.00000000000000	3,058	1.00000000000000	2,680	1.00000000000000
3,148	1.00000000000000	2,737	1.00000000000000	3,058	1.00000000000000	2,679	1.00000000000000
3,148	1.00000000000000	2,733	1.00000000000000	3,058	1.00000000000000	2,678	1.00000000000000
3,147	1.00000000000000	2,732	1.00000000000000	3,057	1.00000000000000	2,678	1.00000000000000
3,144	1.00000000000000	2,732	1.00000000000000	3,053	1.00000000000000	2,676	1.00000000000000
3,144	1.00000000000000	2,730	1.00000000000000	3,053	1.00000000000000	2,675	1.00000000000000
3,143	1.00000000000000	2,729	1.00000000000000	3,053	1.00000000000000	2,675	1.00000000000000
3,143	1.00000000000000	2,729	1.00000000000000	3,050	1.00000000000000	2,674	1.00000000000000
3,138	1.00000000000000	2,728	1.00000000000000	3,047	1.00000000000000	2,674	1.00000000000000
3,138	1.00000000000000	2,727	1.00000000000000	3,047	1.00000000000000	2,672	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,138	1.00000000000000	2,727	1.00000000000000	3,046	1.00000000000000	2,671	1.00000000000000
3,137	1.00000000000000	2,727	1.00000000000000	3,045	1.00000000000000	2,669	1.00000000000000
3,136	1.00000000000000	2,727	1.00000000000000	3,041	1.00000000000000	2,669	1.00000000000000
3,129	1.00000000000000	2,726	1.00000000000000	3,041	1.00000000000000	2,668	1.00000000000000
3,127	1.00000000000000	2,726	1.00000000000000	3,039	1.00000000000000	2,666	1.00000000000000
3,124	1.00000000000000	2,724	1.00000000000000	3,039	1.00000000000000	2,665	1.00000000000000
3,124	1.00000000000000	2,723	1.00000000000000	3,039	1.00000000000000	2,665	1.00000000000000
3,122	1.00000000000000	2,720	1.00000000000000	3,039	1.00000000000000	2,663	1.00000000000000
3,122	1.00000000000000	2,720	1.00000000000000	3,036	1.00000000000000	2,662	1.00000000000000
3,121	1.00000000000000	2,718	1.00000000000000	3,034	1.00000000000000	2,662	1.00000000000000
3,119	1.00000000000000	2,717	1.00000000000000	3,031	1.00000000000000	2,661	1.00000000000000
3,118	1.00000000000000	2,716	1.00000000000000	3,026	1.00000000000000	2,658	1.00000000000000
3,116	1.00000000000000	2,716	1.00000000000000	3,026	1.00000000000000	2,657	1.00000000000000
3,104	1.00000000000000	2,715	1.00000000000000	3,025	1.00000000000000	2,657	1.00000000000000
3,102	1.00000000000000	2,715	1.00000000000000	3,022	1.00000000000000	2,656	1.00000000000000
3,098	1.00000000000000	2,714	1.00000000000000	3,018	1.00000000000000	2,654	1.00000000000000
3,097	1.00000000000000	2,714	1.00000000000000	3,018	1.00000000000000	2,651	1.00000000000000
3,096	1.00000000000000	2,713	1.00000000000000	3,016	1.00000000000000	2,651	1.00000000000000
3,096	1.00000000000000	2,712	1.00000000000000	3,016	1.00000000000000	2,651	1.00000000000000
3,095	1.00000000000000	2,712	1.00000000000000	3,015	1.00000000000000	2,651	1.00000000000000
3,093	1.00000000000000	2,710	1.00000000000000	3,010	1.00000000000000	2,650	1.00000000000000
3,089	1.00000000000000	2,710	1.00000000000000	3,010	1.00000000000000	2,648	1.00000000000000
3,088	1.00000000000000	2,710	1.00000000000000	3,009	1.00000000000000	2,647	1.00000000000000
3,087	1.00000000000000	2,710	1.00000000000000	3,008	1.00000000000000	2,646	1.00000000000000
3,086	1.00000000000000	2,709	1.00000000000000	3,008	1.00000000000000	2,646	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,086	1.00000000000000	2,706	1.00000000000000	3,008	1.00000000000000	2,646	1.00000000000000
3,086	1.00000000000000	2,706	1.00000000000000	3,005	1.00000000000000	2,646	1.00000000000000
3,084	1.00000000000000	2,700	1.00000000000000	3,005	1.00000000000000	2,645	1.00000000000000
3,082	1.00000000000000	2,700	1.00000000000000	3,001	1.00000000000000	2,644	1.00000000000000
3,081	1.00000000000000	2,699	1.00000000000000	3,001	1.00000000000000	2,638	1.00000000000000
3,080	1.00000000000000	2,699	1.00000000000000	3,000	1.00000000000000	2,638	1.00000000000000
3,080	1.00000000000000	2,699	1.00000000000000	3,000	1.00000000000000	2,636	1.00000000000000
3,077	1.00000000000000	2,698	1.00000000000000	2,999	1.00000000000000	2,636	1.00000000000000
3,076	1.00000000000000	2,697	1.00000000000000	2,999	1.00000000000000	2,636	1.00000000000000
3,075	1.00000000000000	2,696	1.00000000000000	2,998	1.00000000000000	2,634	1.00000000000000
3,074	1.00000000000000	2,696	1.00000000000000	2,996	1.00000000000000	2,634	1.00000000000000
3,074	1.00000000000000	2,695	1.00000000000000	2,993	1.00000000000000	2,633	1.00000000000000
3,073	1.00000000000000	2,695	1.00000000000000	2,993	1.00000000000000	2,633	1.00000000000000
3,070	1.00000000000000	2,694	1.00000000000000	2,993	1.00000000000000	2,632	1.00000000000000
3,069	1.00000000000000	2,693	1.00000000000000	2,992	1.00000000000000	2,631	1.00000000000000
3,066	1.00000000000000	2,693	1.00000000000000	2,991	1.00000000000000	2,629	1.00000000000000
3,066	1.00000000000000	2,693	1.00000000000000	2,990	1.00000000000000	2,628	1.00000000000000
3,065	1.00000000000000	2,693	1.00000000000000	2,987	1.00000000000000	2,625	1.00000000000000
3,064	1.00000000000000	2,691	1.00000000000000	2,986	1.00000000000000	2,623	1.00000000000000
3,061	1.00000000000000	2,690	1.00000000000000	2,986	1.00000000000000	2,622	1.00000000000000
3,060	1.00000000000000	2,690	1.00000000000000	2,984	1.00000000000000	2,621	1.00000000000000
3,059	1.00000000000000	2,688	1.00000000000000	2,982	1.00000000000000	2,620	1.00000000000000
3,058	1.00000000000000	2,687	1.00000000000000	2,982	1.00000000000000	2,618	1.00000000000000
3,057	1.00000000000000	2,687	1.00000000000000	2,979	1.00000000000000	2,617	1.00000000000000
3,050	1.00000000000000	2,686	1.00000000000000	2,977		2,616	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,049	1.00000000000000	2,684	1.00000000000000	2,977	1.00000000000000	2,614	1.00000000000000
3,048	1.00000000000000	2,684	1.00000000000000	2,976	1.00000000000000	2,612	1.00000000000000
3,046	1.00000000000000	2,679	1.00000000000000	2,975	1.00000000000000	2,612	1.00000000000000
3,046	1.00000000000000	2,678	1.00000000000000	2,974	1.00000000000000	2,612	1.00000000000000
3,045	1.00000000000000	2,677	1.00000000000000	2,973	1.00000000000000	2,612	1.00000000000000
3,045	1.00000000000000	2,676	1.00000000000000	2,968	1.00000000000000	2,609	1.00000000000000
3,042	1.00000000000000	2,676	1.00000000000000	2,968	1.00000000000000	2,608	1.00000000000000
3,041	1.00000000000000	2,676	1.00000000000000	2,965	1.00000000000000	2,607	1.00000000000000
3,040	1.00000000000000	2,675	1.00000000000000	2,964	1.00000000000000	2,607	1.00000000000000
3,039	1.00000000000000	2,674	1.00000000000000	2,962	1.00000000000000	2,606	1.00000000000000
3,038	1.00000000000000	2,674	1.00000000000000	2,962	1.00000000000000	2,606	1.00000000000000
3,037	1.00000000000000	2,672	1.00000000000000	2,958	1.00000000000000	2,605	1.00000000000000
3,035	1.00000000000000	2,669	1.00000000000000	2,957	1.00000000000000	2,605	1.00000000000000
3,035	1.00000000000000	2,668	1.00000000000000	2,955	1.00000000000000	2,604	1.00000000000000
3,034	1.00000000000000	2,667	1.00000000000000	2,954	1.00000000000000	2,603	1.00000000000000
3,033	1.00000000000000	2,665	1.00000000000000	2,953	1.00000000000000	2,601	1.00000000000000
3,033	1.00000000000000	2,665	1.00000000000000	2,946	1.00000000000000	2,598	1.00000000000000
3,030	1.00000000000000	2,662	1.00000000000000	2,946	1.00000000000000	2,598	1.00000000000000
3,025	1.00000000000000	2,662	1.00000000000000	2,945	1.00000000000000	2,597	1.00000000000000
3,025	1.00000000000000	2,662	1.00000000000000	2,944	1.00000000000000	2,597	1.00000000000000
3,024	1.00000000000000	2,662	1.00000000000000	2,944	1.00000000000000	2,595	1.00000000000000
3,019	1.00000000000000	2,662	1.00000000000000	2,944	1.00000000000000	2,595	1.00000000000000
3,018	1.00000000000000	2,662	1.00000000000000	2,944	1.00000000000000	2,594	1.00000000000000
3,016	1.00000000000000	2,660	1.00000000000000	2,943	1.00000000000000	2,594	1.00000000000000
3,015	1.00000000000000	2,660	1.00000000000000	2,943	1.00000000000000	2,593	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
3,013	1.00000000000000	2,658	1.00000000000000	2,937	1.00000000000000	2,593	1.00000000000000
3,012	1.00000000000000	2,656	1.00000000000000	2,936	1.00000000000000	2,592	1.00000000000000
3,011	1.00000000000000	2,655	1.00000000000000	2,936	1.00000000000000	2,591	1.00000000000000
3,010	1.00000000000000	2,652	1.00000000000000	2,935	1.00000000000000	2,591	1.00000000000000
3,009	1.00000000000000	2,652	1.00000000000000	2,934	1.00000000000000	2,590	1.00000000000000
3,007	1.00000000000000	2,652	1.00000000000000	2,932	1.00000000000000	2,589	1.00000000000000
3,006	1.00000000000000	2,651	1.00000000000000	2,931	1.00000000000000	2,582	1.00000000000000
3,006	1.00000000000000	2,650	1.00000000000000	2,931	1.00000000000000	2,580	1.00000000000000
3,005	1.00000000000000	2,650	1.00000000000000	2,930	1.00000000000000	2,578	1.00000000000000
3,002	1.00000000000000	2,649	1.00000000000000	2,929	1.00000000000000	2,578	1.00000000000000
3,001	1.00000000000000	2,648	1.00000000000000	2,927	1.00000000000000	2,576	1.00000000000000
2,999	1.00000000000000	2,646	1.00000000000000	2,926	1.00000000000000	2,576	1.00000000000000
2,999	1.00000000000000	2,645	1.00000000000000	2,922	1.00000000000000	2,576	1.00000000000000
2,997	1.00000000000000	2,638	1.00000000000000	2,922	1.00000000000000	2,576	1.00000000000000
2,997	1.00000000000000	2,636	1.00000000000000	2,917	1.00000000000000	2,571	1.00000000000000
2,995	1.00000000000000	2,635	1.00000000000000	2,913	1.00000000000000	2,570	1.00000000000000
2,994	1.00000000000000	2,634	1.00000000000000	2,912	1.00000000000000	2,568	1.00000000000000
2,993	1.00000000000000	2,631	1.00000000000000	2,911	1.00000000000000	2,564	1.00000000000000
2,991	1.00000000000000	2,630	1.00000000000000	2,910	1.00000000000000	2,563	1.00000000000000
2,989	1.00000000000000	2,629	1.00000000000000	2,909	1.00000000000000	2,563	1.00000000000000
2,986	1.00000000000000	2,629	1.00000000000000	2,908	1.00000000000000	2,563	1.00000000000000
2,985	1.00000000000000	2,629	1.00000000000000	2,906	1.00000000000000	2,562	1.00000000000000
2,985	1.00000000000000	2,627	1.00000000000000	2,906	1.00000000000000	2,556	1.00000000000000
2,983	1.00000000000000	2,626	1.00000000000000	2,906	1.00000000000000	2,554	1.00000000000000
2,977	1.00000000000000	2,626	1.00000000000000	2,905	1.00000000000000	2,552	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
2,974	1.00000000000000	2,625	1.00000000000000	2,905	1.00000000000000	2,550	1.00000000000000
2,973	1.00000000000000	2,623	1.00000000000000	2,896	1.00000000000000	2,549	1.00000000000000
2,969	1.00000000000000	2,623	1.00000000000000	2,896	1.00000000000000	2,549	1.00000000000000
2,965	1.00000000000000	2,619	1.00000000000000	2,895	1.00000000000000	2,549	1.00000000000000
2,964	1.00000000000000	2,618	1.00000000000000	2,894	1.00000000000000	2,548	1.00000000000000
2,964	1.00000000000000	2,618	1.00000000000000	2,893	1.00000000000000	2,547	1.00000000000000
2,963	1.00000000000000	2,618	1.00000000000000	2,891	1.00000000000000	2,545	1.00000000000000
2,962	1.00000000000000	2,615	1.00000000000000	2,889	1.00000000000000	2,539	1.00000000000000
2,957	1.00000000000000	2,614	1.00000000000000	2,887	1.00000000000000	2,539	1.00000000000000
2,954	1.00000000000000	2,612	1.00000000000000	2,883	1.00000000000000	2,538	1.00000000000000
2,952	1.00000000000000	2,611	1.00000000000000	2,878	1.00000000000000	2,537	1.00000000000000
2,948	1.00000000000000	2,609	1.00000000000000	2,877	1.00000000000000	2,536	1.00000000000000
2,947	1.00000000000000	2,609	1.00000000000000	2,877	1.00000000000000	2,536	1.00000000000000
2,944	1.00000000000000	2,609	1.00000000000000	2,874	1.00000000000000	2,536	1.00000000000000
2,943	1.00000000000000	2,608	1.00000000000000	2,872	1.00000000000000	2,534	1.00000000000000
2,943	1.00000000000000	2,608	1.00000000000000	2,869	1.00000000000000	2,533	1.00000000000000
2,940	1.00000000000000	2,608	1.00000000000000	2,867	1.00000000000000	2,533	1.00000000000000
2,940	1.00000000000000	2,606	1.00000000000000	2,865	1.00000000000000	2,533	1.00000000000000
2,936	1.00000000000000	2,605	1.00000000000000	2,862	1.00000000000000	2,532	1.00000000000000
2,935	1.00000000000000	2,604	1.00000000000000	2,859	1.00000000000000	2,531	1.00000000000000
2,934	1.00000000000000	2,602	1.00000000000000	2,858	1.00000000000000	2,528	1.00000000000000
2,934	1.00000000000000	2,601	1.00000000000000	2,857	1.00000000000000	2,526	1.00000000000000
2,931	1.00000000000000	2,601	1.00000000000000	2,854	1.00000000000000	2,525	1.00000000000000
2,931	1.00000000000000	2,600	1.00000000000000	2,854	1.00000000000000	2,522	1.00000000000000
2,926	1.00000000000000	2,598	1.00000000000000	2,851		2,520	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
2,923	1.00000000000000	2,597	1.00000000000000	2,849	1.00000000000000	2,517	1.00000000000000
2,923	1.00000000000000	2,596	1.00000000000000	2,849	1.00000000000000	2,516	1.00000000000000
2,922	1.00000000000000	2,592	1.00000000000000	2,848	1.00000000000000	2,516	1.00000000000000
2,917	1.00000000000000	2,590	1.00000000000000	2,848	1.00000000000000	2,515	1.00000000000000
2,917	1.00000000000000	2,588	1.00000000000000	2,847	1.00000000000000	2,511	1.00000000000000
2,916	1.00000000000000	2,586	1.00000000000000	2,846	1.00000000000000	2,511	1.00000000000000
2,915	1.00000000000000	2,586	1.00000000000000	2,845	1.00000000000000	2,509	1.00000000000000
2,914	1.00000000000000	2,585	1.00000000000000	2,843	1.00000000000000	2,508	1.00000000000000
2,913	1.00000000000000	2,582	1.00000000000000	2,843	1.00000000000000	2,508	1.00000000000000
2,911	1.00000000000000	2,581	1.00000000000000	2,842	1.00000000000000	2,507	1.00000000000000
2,911	1.00000000000000	2,580	1.00000000000000	2,840	1.00000000000000	2,506	1.00000000000000
2,909	1.00000000000000	2,580	1.00000000000000	2,840	1.00000000000000	2,506	1.00000000000000
2,901	1.00000000000000	2,579	1.00000000000000	2,838	1.00000000000000	2,505	1.00000000000000
2,901	1.00000000000000	2,579	1.00000000000000	2,837	1.00000000000000	2,505	1.00000000000000
2,900	1.00000000000000	2,579	1.00000000000000	2,831	1.00000000000000	2,501	1.00000000000000
2,900	1.00000000000000	2,578	1.00000000000000	2,827	1.00000000000000	2,498	1.00000000000000
2,896	1.00000000000000	2,578	1.00000000000000	2,825	1.00000000000000	2,497	1.00000000000000
2,895	1.00000000000000	2,575	1.00000000000000	2,824	1.00000000000000	2,496	1.00000000000000
2,894	1.00000000000000	2,575	1.00000000000000	2,824	1.00000000000000	2,496	1.00000000000000
2,891	1.00000000000000	2,571	1.00000000000000	2,820	1.00000000000000	2,495	1.00000000000000
2,890	1.00000000000000	2,564	1.00000000000000	2,817	1.00000000000000	2,495	1.00000000000000
2,890	1.00000000000000	2,561	1.00000000000000	2,816	1.00000000000000	2,492	1.00000000000000
2,886	1.00000000000000	2,559	1.00000000000000	2,816	1.00000000000000	2,491	1.00000000000000
2,882	1.00000000000000	2,557	1.00000000000000	2,815	1.00000000000000	2,486	1.00000000000000
2,881	1.00000000000000	2,556	1.00000000000000	2,814	1.00000000000000	2,482	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
2,880	1.00000000000000	2,555	1.00000000000000	2,812	1.00000000000000	2,482	1.00000000000000
2,876	1.00000000000000	2,554	1.00000000000000	2,809	1.00000000000000	2,481	1.00000000000000
2,869	1.00000000000000	2,551	1.00000000000000	2,805	1.00000000000000	2,480	1.00000000000000
2,868	1.00000000000000	2,550	1.00000000000000	2,800	1.00000000000000	2,479	1.00000000000000
2,862	1.00000000000000	2,550	1.00000000000000	2,800	1.00000000000000	2,475	1.00000000000000
2,857	1.00000000000000	2,549	1.00000000000000	2,800	1.00000000000000	2,472	1.00000000000000
2,854	1.00000000000000	2,548	1.00000000000000	2,800	1.00000000000000	2,470	1.00000000000000
2,853	1.00000000000000	2,547	1.00000000000000	2,800	1.00000000000000	2,469	1.00000000000000
2,853	1.00000000000000	2,545	1.00000000000000	2,791	1.00000000000000	2,467	1.00000000000000
2,850	1.00000000000000	2,542	1.00000000000000	2,790	1.00000000000000	2,465	1.00000000000000
2,843	1.00000000000000	2,540	1.00000000000000	2,790	1.00000000000000	2,463	1.00000000000000
2,843	1.00000000000000	2,540	1.00000000000000	2,781	1.00000000000000	2,462	1.00000000000000
2,838	1.00000000000000	2,539	1.00000000000000	2,780	1.00000000000000	2,461	1.00000000000000
2,836	1.00000000000000	2,539	1.00000000000000	2,778	1.00000000000000	2,460	1.00000000000000
2,834	1.00000000000000	2,537	1.00000000000000	2,778	1.00000000000000	2,459	1.00000000000000
2,834	1.00000000000000	2,537	1.00000000000000	2,776	1.00000000000000	2,458	1.00000000000000
2,831	1.00000000000000	2,537	1.00000000000000	2,773	1.00000000000000	2,456	1.00000000000000
2,831	1.00000000000000	2,535	1.00000000000000	2,772	1.00000000000000	2,454	1.00000000000000
2,826	1.00000000000000	2,533	1.00000000000000	2,767	1.00000000000000	2,454	1.00000000000000
2,820	1.00000000000000	2,532	1.00000000000000	2,766	1.00000000000000	2,453	1.00000000000000
2,819	1.00000000000000	2,529	1.00000000000000	2,763	1.00000000000000	2,451	1.00000000000000
2,817	1.00000000000000	2,525	1.00000000000000	2,760	1.00000000000000	2,451	1.00000000000000
2,813	1.00000000000000	2,524	1.00000000000000	2,758	1.00000000000000	2,450	1.00000000000000
2,809	1.00000000000000	2,522	1.00000000000000	2,756	1.00000000000000	2,438	1.00000000000000
2,809	1.00000000000000	2,521	1.00000000000000	2,756	1.00000000000000	2,437	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
2,805	1.00000000000000	2,520	1.00000000000000	2,754	1.00000000000000	2,435	1.00000000000000
2,799	1.00000000000000	2,517	1.00000000000000	2,753	1.00000000000000	2,434	1.00000000000000
2,796	1.00000000000000	2,516	1.00000000000000	2,753	1.00000000000000	2,432	1.00000000000000
2,796	1.00000000000000	2,514	1.00000000000000	2,749	1.00000000000000	2,429	1.00000000000000
2,777	1.00000000000000	2,513	1.00000000000000	2,749	1.00000000000000	2,427	1.00000000000000
2,774	1.00000000000000	2,513	1.00000000000000	2,745	1.00000000000000	2,426	1.00000000000000
2,772	1.00000000000000	2,512	1.00000000000000	2,742	1.00000000000000	2,424	1.00000000000000
2,771	1.00000000000000	2,510	1.00000000000000	2,742	1.00000000000000	2,423	1.00000000000000
2,756	1.00000000000000	2,509	1.00000000000000	2,739	1.00000000000000	2,423	1.00000000000000
2,755	1.00000000000000	2,505	1.00000000000000	2,737	1.00000000000000	2,418	1.00000000000000
2,755	1.00000000000000	2,503	1.00000000000000	2,733	1.00000000000000	2,415	1.00000000000000
2,748	1.00000000000000	2,502	1.00000000000000	2,731	1.00000000000000	2,414	1.00000000000000
2,748	1.00000000000000	2,500	1.00000000000000	2,725	1.00000000000000	2,414	1.00000000000000
2,747	1.00000000000000	2,498	1.00000000000000	2,723	1.00000000000000	2,413	1.00000000000000
2,739	1.00000000000000	2,495	1.00000000000000	2,722	1.00000000000000	2,411	1.00000000000000
2,730	1.00000000000000	2,493	1.00000000000000	2,721	1.00000000000000	2,410	1.00000000000000
2,723	1.00000000000000	2,487	1.00000000000000	2,721	1.00000000000000	2,409	1.00000000000000
2,717	1.00000000000000	2,484	1.00000000000000	2,717	1.00000000000000	2,398	1.00000000000000
2,713	1.00000000000000	2,478	1.00000000000000	2,717	1.00000000000000	2,396	1.00000000000000
2,711	1.00000000000000	2,478	1.00000000000000	2,711	1.00000000000000	2,396	1.00000000000000
2,705	1.00000000000000	2,471	1.00000000000000	2,707	1.00000000000000	2,396	1.00000000000000
2,701	1.00000000000000	2,470	1.00000000000000	2,707	1.00000000000000	2,390	1.00000000000000
2,698	1.00000000000000	2,470	1.00000000000000	2,706	1.00000000000000	2,390	1.00000000000000
2,685	1.00000000000000	2,468	1.00000000000000	2,695	1.00000000000000	2,388	1.00000000000000
2,676	1.00000000000000	2,467	1.00000000000000	2,693	1.00000000000000	2,387	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
2,676	1.00000000000000	2,467	1.00000000000000	2,691	1.00000000000000	2,385	1.00000000000000
2,670	1.00000000000000	2,463	1.00000000000000	2,691	1.00000000000000	2,375	1.00000000000000
2,667	1.00000000000000	2,462	1.00000000000000	2,684	1.00000000000000	2,369	1.00000000000000
2,659	1.00000000000000	2,462	1.00000000000000	2,683	1.00000000000000	2,365	1.00000000000000
2,656	1.00000000000000	2,461	1.00000000000000	2,675	1.00000000000000	2,364	1.00000000000000
2,648	1.00000000000000	2,460	1.00000000000000	2,674	1.00000000000000	2,363	1.00000000000000
2,645	1.00000000000000	2,455	1.00000000000000	2,673	1.00000000000000	2,361	1.00000000000000
2,640	1.00000000000000	2,453	1.00000000000000	2,671	1.00000000000000	2,357	1.00000000000000
2,637	1.00000000000000	2,453	1.00000000000000	2,671	1.00000000000000	2,354	1.00000000000000
2,621	1.00000000000000	2,452	1.00000000000000	2,669	1.00000000000000	2,350	1.00000000000000
2,613	1.00000000000000	2,452	1.00000000000000	2,667	1.00000000000000	2,348	1.00000000000000
2,610	1.00000000000000	2,451	1.00000000000000	2,666	1.00000000000000	2,345	1.00000000000000
2,607	1.00000000000000	2,449	1.00000000000000	2,649	1.00000000000000	2,343	1.00000000000000
2,606	1.00000000000000	2,445	1.00000000000000	2,646	1.00000000000000	2,331	1.00000000000000
2,601	1.00000000000000	2,445	1.00000000000000	2,644	1.00000000000000	2,327	1.00000000000000
2,589	1.00000000000000	2,445	1.00000000000000	2,643	1.00000000000000	2,326	1.00000000000000
2,582	1.00000000000000	2,438	1.00000000000000	2,642	1.00000000000000	2,323	1.00000000000000
2,579	1.00000000000000	2,437	1.00000000000000	2,642	1.00000000000000	2,307	1.00000000000000
2,563	1.00000000000000	2,437	0.99997792550000	2,642	1.00000000000000	2,300	0.99991560940000
2,557	1.00000000000000	2,434	1.00000000000000	2,636	1.00000000000000	2,299	1.00000000000000
2,541	1.00000000000000	2,431	1.00000000000000	2,636	1.00000000000000	2,298	1.00000000000000
2,539	1.00000000000000	2,429	1.00000000000000	2,635	1.00000000000000	2,296	1.00000000000000
2,538	1.00000000000000	2,429	1.00000000000000	2,635	1.00000000000000	2,290	1.00000000000000
2,528	1.00000000000000	2,428	1.00000000000000	2,634	1.00000000000000	2,286	1.00000000000000
2,523	1.00000000000000	2,427		2,634		2,279	1.00000000000000

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
2,512	1.00000000000000	2,424	1.00000000000000	2,629	1.00000000000000	2,271	1.00000000000000
2,500	1.00000000000000	2,422	1.00000000000000	2,625	1.00000000000000	2,271	1.00000000000000
2,465	1.00000000000000	2,420	1.00000000000000	2,624	1.00000000000000	2,271	1.00000000000000
2,463	1.00000000000000	2,418	1.00000000000000	2,621	1.00000000000000	2,264	1.00000000000000
2,456	1.00000000000000	2,417	1.00000000000000	2,612	1.00000000000000	2,256	1.00000000000000
2,455	1.00000000000000	2,417	1.00000000000000	2,610	1.00000000000000	2,255	1.00000000000000
2,452	1.00000000000000	2,416	1.00000000000000	2,607	1.00000000000000	2,249	1.00000000000000
2,415	1.00000000000000	2,414	1.00000000000000	2,603	1.00000000000000	2,227	1.00000000000000
		2,406	1.00000000000000	2,601	1.00000000000000		
		2,405	1.00000000000000	2,590	1.00000000000000		
		2,403	1.00000000000000	2,585	1.00000000000000		
		2,394	1.00000000000000	2,585	1.00000000000000		
		2,393	1.00000000000000	2,578	1.00000000000000		
		2,386	1.00000000000000	2,578	1.00000000000000		
		2,385	1.00000000000000	2,573	1.00000000000000		
		2,383	1.00000000000000	2,561	1.00000000000000		
		2,379	1.00000000000000	2,552	1.00000000000000		
		2,374	1.00000000000000	2,549	1.00000000000000		
		2,373	1.00000000000000	2,539	1.00000000000000		
		2,371	1.00000000000000	2,530	1.00000000000000		
		2,367	1.00000000000000	2,529	1.00000000000000		
		2,364	1.00000000000000	2,527	1.00000000000000		
		2,327	1.00000000000000	2,521	1.00000000000000		
		2,322	1.00000000000000	2,517	1.00000000000000		
		2,319	1.00000000000000	2,509	1.00000000000000		

Table 2 - System Capacity Availability Table

Winter Total Available Capacity (MW)	Availability	Spring Total Available Capacity (MW)	Availability	Summer Total Available Capacity (MW)	Availability	Fall Total Available Capacity (MW)	Availability
5,972	0.99983205800000	5,427	0.99997792550000	6,360	0.99496488000000	5,698	0.99991560940000
		2,300	1.00000000000000	2,509	1.00000000000000		
		2,297	1.00000000000000	2,477	1.00000000000000		
		2,295	1.00000000000000	2,444	1.00000000000000		
		2,293	1.00000000000000	2,425	1.00000000000000		
		2,290	1.00000000000000	2,409	1.00000000000000		
		2,288	1.00000000000000	2,391	1.00000000000000		
		2,283	1.00000000000000	2,388	1.00000000000000		

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
5,972	0.00016794200000	5,427	0.00002207450000	6,360	0.00503512000000	5,698	0.00008439060000
5,905	0.00011650500000	5,414	0.00002043370000	6,321	0.00418359000000	5,695	0.00008118810000
5,846	0.00008436910000	5,332	0.00001266800000	6,282	0.00348774000000	5,655	0.00006657120000
5,844	0.00008296880000	5,319	0.00001156880000	6,247	0.00298950000000	5,621	0.00005426380000
5,835	0.00007932350000	5,296	0.00001011370000	6,186	0.00228359000000	5,609	0.00005041010000
5,827	0.00007627660000	5,271	0.00000863029000	6,110	0.00154669000000	5,583	0.00004314950000
5,793	0.00006262080000	5,255	0.00000777105000	6,100	0.00149413000000	5,581	0.00004363120000
5,787	0.00006055080000	5,255	0.00000772286000	6,100	0.00147274000000	5,545	0.00003624340000
5,760	0.00005167390000	5,167	0.00000463224000	6,084	0.00138041000000	5,528	0.00003140670000
5,692	0.00003522120000	5,165	0.00000452017000	6,079	0.00133305000000	5,491	0.00002633930000
5,674	0.00003141680000	5,156	0.00000434818000	6,059	0.00120766000000	5,489	0.00002500170000
5,650	0.00002763130000	5,155	0.00000413626000	6,027	0.00102662000000	5,477	0.00002369960000
5,630	0.00002455320000	5,148	0.00000405504000	6,017	0.00101145000000	5,465	0.00002232510000
5,615	0.00002246250000	5,118	0.00000343119000	6,010	0.00094306100000	5,391	0.00001403980000
5,588	0.00001872890000	5,094	0.00000283647000	6,007	0.00096695000000	5,371	0.00001304470000
5,578	0.00001786340000	5,053	0.00000215099000	5,998	0.00089673900000	5,367	0.00001200070000
5,553	0.00001557830000	5,043	0.00000204203000	5,991	0.00086952500000	5,364	0.00001235510000
5,515	0.00001239900000	5,042	0.00000212017000	5,989	0.00087839400000	5,350	0.00001148180000
5,503	0.00001147180000	5,035	0.00000195090000	5,980	0.00083048500000	5,334	0.00001047850000
5,488	0.00001054130000	5,032	0.00000187644000	5,968	0.00078507400000	5,323	0.00000923264000
5,481	0.00001010290000	5,012	0.00000119444000	5,961	0.00075380400000	5,286	0.00000739564000
5,469	0.00000944805000	5,003	0.00000160332000	5,953	0.00070569700000	5,283	0.00000766418000
5,457	0.00000872310000	4,988	0.00000141663000	5,944	0.00069485600000	5,254	0.00000632184000

Table 3 - System LOLP Table

Winter System Load Level (MW)	Loss of Load Probability	Spring System Load Level (MW)	Loss of Load Probability	Summer System Load Level (MW)	Loss of Load Probability	Fall System Load Level (MW)	Loss of Load Probability
5,438	0.00000775839000	4,972	0.00000134179000	5,925	0.00060773400000	5,226	0.00000509297000
5,438	0.00000771005000	4,969	0.00000088559500	5,916	0.00060701500000	5,203	0.00000437930000
5,428	0.00000707867000	4,968	0.00000130732000	5,914	0.00060430600000	5,186	0.00000413019000
5,427	0.00000724840000	4,951	0.00000114541000	5,899	0.00055118000000	5,185	0.00000413019000
5,423	0.00000686522000	4,944	0.00000106526000	5,893	0.00053712900000	5,170	0.00000377621000
5,411	0.00000633842000	4,916	0.00000093126200	5,892	0.00051538800000	5,129	0.00000272911000
5,401	0.00000606886000	4,903	0.00000080536800	5,891	0.00053429100000	5,076	0.00000193866000
5,397	0.00000585080000	4,902	0.00000080522600	5,880	0.00048454400000	5,027	0.00000129158000
5,396	0.00000588628000	4,893	0.00000054535100	5,874	0.00048173100000	5,016	0.00000121646000
5,388	0.00000567106000	4,883	0.00000071869400	5,871	0.00047957500000	4,988	0.00000101646000
5,388	0.00000570448000	4,879	0.00000047307600	5,871	0.00046949700000	4,987	0.0000098359200
5,366	0.00000497503000	4,873	0.00000066319100	5,864	0.00044584400000	4,979	0.0000094478900
5,361	0.00000482151000	4,870	0.00000065009100	5,863	0.00044354400000	4,965	0.0000098872500
5,360	0.00000467542000	4,863	0.00000065343600	5,857	0.00044584400000	4,950	0.0000084958800
5,345	0.00000435800000	4,860	0.00000064029600	5,842	0.00041429100000	4,926	0.0000072832100
5,333	0.00000401407000	4,854	0.00000057911600	5,839	0.00040573900000	4,906	0.0000056732600
5,333	0.00000403854000	4,830	0.00000052542100	5,833	0.00040153100000	4,903	0.0000062798300
5,329	0.00000393704000	4,816	0.00000044962700	5,830	0.00039102100000	4,901	0.0000062370400
5,324	0.00000381507000	4,816	0.00000047419000	5,823	0.00035766400000	4,890	0.0000058650100
5,318	0.00000353983000	4,809	0.00000028808700	5,822	0.00035761500000	4,889	0.0000055961400
5,315	0.00000360362000	4,802	0.0000040853900	5,815	0.00035946000000	4,879	0.0000054066400
5,302	0.00000331978000	4,790	0.00000039695900	5,814	0.00034467700000	4,877	0.0000048761300
5,296	0.00000319661000	4,790	0.00000037373700	5,813	0.00035545500000	4,875	0.0000048752600

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
5,296	0.00000317605000	4,775	0.00000035572000	5,811	0.00033567800000	4,874	0.00000046524200
5,293	0.00000313585000	4,770	0.00000032999100	5,809	0.00035375900000	4,864	0.00000044311200
5,289	0.00000305786000	4,750	0.00000020303100	5,803	0.00033392300000	4,849	0.00000047477700
5,282	0.00000285334000	4,740	0.00000026412300	5,803	0.00032853100000	4,845	0.00000045900100
5,269	0.00000264238000	4,739	0.00000026228200	5,802	0.00033214300000	4,840	0.00000036116400
5,259	0.00000247859000	4,738	0.00000026590600	5,802	0.00033926600000	4,837	0.00000030415500
5,246	0.00000242971000	4,726	0.00000024122600	5,793	0.00031824000000	4,830	0.00000038148800
5,230	0.00000209516000	4,722	0.00000024761600	5,783	0.00030164900000	4,825	0.00000040294400
5,224	0.00000201575000	4,717	0.00000015965700	5,783	0.00029847500000	4,819	0.00000031865600
5,223	0.00000200280000	4,713	0.00000027145200	5,782	0.00030812800000	4,818	0.00000031432600
5,222	0.00000199027000	4,708	0.00000026223400	5,777	0.00029055900000	4,814	0.00000030769200
5,221	0.00000198995000	4,704	0.00000021106000	5,777	0.00029359800000	4,792	0.00000026760100
5,219	0.00000195222000	4,686	0.00000018097000	5,768	0.00028412700000	4,782	0.00000024956900
5,215	0.00000190290000	4,684	0.00000012513200	5,768	0.00027825400000	4,776	0.00000026032700
5,212	0.00000186627000	4,680	0.00000021268600	5,763	0.00027206400000	4,774	0.00000026922800
5,201	0.00000170591000	4,678	0.00000021704900	5,758	0.00026092000000	4,773	0.00000023120700
5,187	0.00000165087000	4,669	0.00000010633900	5,751	0.00025269600000	4,757	0.00000021174400
5,180	0.00000152678000	4,661	0.00000010769800	5,744	0.00024349400000	4,753	0.00000019692900
5,178	0.00000149735000	4,657	0.00000014712600	5,742	0.00023970300000	4,724	0.00000016144800
5,177	0.00000147842000	4,655	0.00000014814700	5,741	0.00023216900000	4,723	0.00000016843100
5,162	0.00000134777000	4,648	0.00000009813220	5,741	0.00023940800000	4,720	0.00000016478800
5,155	0.00000122970000	4,639	0.00000013775400	5,728	0.00022848700000	4,720	0.00000019682200
5,148	0.00000122845000	4,636	0.00000013479100	5,725	0.00022132000000	4,717	0.00000015905000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
5,141	0.00000116486000	4,636	0.00000012662200	5,722	0.00022008200000	4,714	0.00000015035300
5,137	0.00000114191000	4,634	0.00000012657500	5,722	0.00022712900000	4,710	0.00000011992900
5,134	0.00000111961000	4,622	0.00000014104100	5,713	0.00020629700000	4,709	0.00000014508500
5,128	0.00000104191000	4,596	0.00000006686410	5,711	0.00020421800000	4,689	0.00000012479900
5,124	0.00000105496000	4,592	0.00000009699850	5,710	0.00020289700000	4,685	0.00000013008600
5,123	0.00000109007000	4,584	0.00000008965870	5,707	0.00019337300000	4,681	0.00000010023800
5,120	0.00000098170000	4,583	0.00000008717700	5,707	0.00019337300000	4,661	0.00000011611600
5,117	0.00000097515600	4,581	0.00000011114400	5,697	0.00019326500000	4,660	0.00000010796200
5,116	0.00000095656200	4,581	0.00000010361100	5,695	0.00018609500000	4,658	0.00000010066700
5,110	0.00000095560400	4,576	0.0000008704840	5,693	0.00018097700000	4,657	0.0000008435140
5,110	0.00000095560400	4,573	0.00000008578700	5,688	0.00018692100000	4,654	0.00000011435600
5,096	0.00000087141600	4,572	0.00000005530910	5,682	0.00017602600000	4,652	0.00000008197220
5,094	0.00000086001200	4,569	0.00000007822240	5,678	0.00017031900000	4,645	0.00000009698080
5,090	0.00000083221200	4,556	0.00000004950990	5,677	0.00017029400000	4,602	0.00000007594300
5,078	0.00000078373200	4,555	0.00000004950990	5,671	0.00015583200000	4,600	0.00000006857770
5,066	0.00000071371600	4,554	0.00000007064940	5,671	0.00015848000000	4,599	0.00000006522830
5,065	0.00000074296300	4,554	0.00000007320650	5,668	0.00015674900000	4,595	0.00000007530280
5,047	0.00000062797900	4,546	0.00000004669190	5,667	0.00016181300000	4,593	0.00000006703690
5,043	0.00000061125300	4,536	0.0000006195220	5,666	0.00016022100000	4,588	0.00000005063850
5,034	0.00000055660100	4,535	0.0000004303890	5,663	0.00016024400000	4,585	0.00000006320070
5,028	0.00000053098900	4,535	0.0000006236430	5,663	0.00016012900000	4,585	0.00000006232830
5,024	0.00000053761300	4,534	0.00000004240590	5,662	0.00015929900000	4,584	0.00000004950990
5,022	0.00000051324600	4,531	0.00000005972260	5,654	0.00015832200000	4,575	0.00000005654120

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
5,022	0.00000053404200	4,525	0.00000003879990	5,653	0.00014039600000	4,574	0.00000004501470
5,021	0.00000052681200	4,519	0.00000003710300	5,644	0.00014255300000	4,560	0.00000004971240
5,016	0.00000050936500	4,519	0.00000003682960	5,640	0.00013726200000	4,560	0.00000005548800
5,015	0.00000052004800	4,518	0.00000005349290	5,632	0.00012431900000	4,559	0.00000005788090
5,014	0.00000052681200	4,506	0.00000006510560	5,627	0.00012499400000	4,551	0.00000005754220
5,010	0.00000051280800	4,501	0.00000003314240	5,626	0.00012495800000	4,538	0.00000004476040
5,007	0.00000046075300	4,499	0.00000003194740	5,626	0.00013132200000	4,537	0.00000004476040
5,005	0.00000047289200	4,498	0.00000004718830	5,624	0.00012766700000	4,532	0.00000004010300
5,004	0.00000046966100	4,490	0.00000003076220	5,623	0.00012357500000	4,522	0.00000003099920
5,002	0.00000046332900	4,490	0.00000002839140	5,622	0.00012501200000	4,517	0.00000003828590
4,996	0.00000043899400	4,490	0.00000003007600	5,620	0.00012361100000	4,512	0.00000004094160
4,995	0.00000043600500	4,487	0.00000004543140	5,619	0.00012019100000	4,509	0.00000004345530
4,994	0.00000043308500	4,483	0.00000002856400	5,615	0.00012221100000	4,507	0.00000002750400
4,989	0.00000042413100	4,480	0.00000005189980	5,613	0.00011877800000	4,507	0.00000003327370
4,988	0.00000042123500	4,479	0.00000002812970	5,611	0.00012149400000	4,506	0.00000002710170
4,987	0.00000041548800	4,474	0.00000004790140	5,608	0.00011235100000	4,498	0.00000002534710
4,986	0.00000041548800	4,473	0.00000003891390	5,603	0.00011549400000	4,497	0.00000003633650
4,985	0.00000041555900	4,470	0.00000002630160	5,602	0.00010801800000	4,496	0.00000003064660
4,981	0.00000040148900	4,468	0.00000003804790	5,599	0.00010977700000	4,495	0.00000003042250
4,974	0.00000036509200	4,462	0.00000004578310	5,597	0.00010494100000	4,484	0.00000002991350
4,973	0.00000040155900	4,461	0.00000003744430	5,595	0.00010093600000	4,477	0.00000002738810
4,963	0.00000034530000	4,461	0.00000003771660	5,594	0.00010621800000	4,466	0.00000003200790
4,961	0.00000034982900	4,460	0.00000004643330	5,594	0.00010207600000	4,464	0.00000002575940

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,959	0.00000034740100	4,449	0.00000002198670	5,589	0.00010790700000	4,461	0.00000002458210
4,954	0.00000033562700	4,444	0.00000002181020	5,578	0.00010488100000	4,460	0.00000002375570
4,942	0.00000030677100	4,443	0.00000003178030	5,578	0.00009484710000	4,460	0.00000002341350
4,937	0.00000028470500	4,433	0.00000002906500	5,573	0.00009424910000	4,459	0.00000001903180
4,931	0.00000028435500	4,426	0.00000003579550	5,568	0.00009528650000	4,447	0.00000002138520
4,931	0.00000028435500	4,410	0.00000003063440	5,565	0.00009476440000	4,441	0.00000002166930
4,929	0.00000028047500	4,410	0.00000001670210	5,563	0.00008620430000	4,439	0.00000002073450
4,927	0.00000027666600	4,408	0.00000002537790	5,559	0.00008856030000	4,434	0.00000001571370
4,925	0.00000028445400	4,407	0.00000002358180	5,554	0.00008328900000	4,433	0.00000002056090
4,924	0.00000027287300	4,404	0.00000001583090	5,553	0.00008569180000	4,431	0.00000001865860
4,924	0.00000026923000	4,404	0.00000002306550	5,552	0.00008377720000	4,431	0.00000001961360
4,924	0.00000027098500	4,403	0.00000002443850	5,551	0.00008378950000	4,426	0.00000001500720
4,921	0.00000026546200	4,403	0.00000001582780	5,549	0.00008185930000	4,419	0.00000002738810
4,920	0.00000026546200	4,397	0.00000001511790	5,548	0.00008426660000	4,419	0.00000001422010
4,920	0.00000026366400	4,395	0.00000002202400	5,547	0.00008658190000	4,415	0.00000002199840
4,919	0.00000027478300	4,394	0.00000002838750	5,538	0.00008137090000	4,405	0.00000001659810
4,919	0.00000024813300	4,388	0.00000001309670	5,537	0.00007478250000	4,404	0.00000001753280
4,917	0.00000025824800	4,386	0.00000002559850	5,530	0.00007346400000	4,404	0.00000001562930
4,913	0.00000025126000	4,379	0.00000002393160	5,530	0.00007561030000	4,400	0.00000001573140
4,908	0.00000024274600	4,379	0.00000001269280	5,528	0.00007261040000	4,399	0.00000001573450
4,908	0.00000024274600	4,378	0.00000001936900	5,527	0.00006937930000	4,399	0.00000001229170
4,907	0.00000024106100	4,371	0.00000002271220	5,527	0.00007348560000	4,396	0.00000001183540
4,907	0.00000023791800	4,369	0.00000001834980	5,524	0.00007181000000	4,388	0.00000001574360

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Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,903	0.00000023449500	4,366	0.00000001166040	5,521	0.00007131690000	4,387	0.00000002138520
4,901	0.00000022971700	4,362	0.00000001156490	5,519	0.00006549700000	4,387	0.00000001120750
4,899	0.00000022810400	4,361	0.00000002075910	5,516	0.00006891020000	4,387	0.00000001751920
4,898	0.00000022352600	4,359	0.00000001712750	5,513	0.00006474160000	4,381	0.00000001337500
4,897	0.00000022340900	4,358	0.00000001738140	5,510	0.00006582390000	4,381	0.00000001281430
4,895	0.00000022340900	4,340	0.00000000967509	5,507	0.00006851300000	4,379	0.00000001037990
4,890	0.00000021282300	4,334	0.00000000930254	5,507	0.00006850300000	4,377	0.00000001297170
4,885	0.00000020693800	4,333	0.00000001739150	5,505	0.00006286770000	4,374	0.00000001013280
4,885	0.00000021289800	4,332	0.00000000915553	5,504	0.00006465530000	4,366	0.00000001469190
4,884	0.00000021142000	4,330	0.00000000894440	5,501	0.00005935310000	4,352	0.00000000821120
4,884	0.00000020550100	4,328	0.00000001380900	5,499	0.00006281220000	4,348	0.00000000998613
4,881	0.00000019718800	4,327	0.00000001612390	5,493	0.00006074020000	4,346	0.00000001046450
4,879	0.00000019175400	4,327	0.00000001711750	5,492	0.00005634780000	4,345	0.00000000969599
4,878	0.00000019309400	4,327	0.00000000874029	5,490	0.00005902430000	4,344	0.00000001278880
4,878	0.00000019979900	4,326	0.00000000860921	5,486	0.00005760810000	4,343	0.00000000795401
4,876	0.00000019570700	4,326	0.00000000867094	5,486	0.00005799310000	4,336	0.00000001491990
4,873	0.00000018886100	4,322	0.00000001540080	5,480	0.00005570610000	4,335	0.00000001070730
4,868	0.00000018363400	4,318	0.00000001493500	5,480	0.00005628120000	4,335	0.00000001184260
4,866	0.00000018102400	4,313	0.00000000789141	5,480	0.00005860260000	4,333	0.00000000735241
4,864	0.00000017857300	4,311	0.00000000752994	5,478	0.00005928310000	4,331	0.00000000908307
4,863	0.00000017976400	4,310	0.00000000764619	5,474	0.00005660650000	4,330	0.00000000924117
4,857	0.00000016754800	4,309	0.00000000758703	5,471	0.00005563190000	4,328	0.00000000874202
4,857	0.00000016866100	4,308	0.00000001393580	5,470	0.00004986680000	4,324	0.00000000684956

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Winter		Spring		Summer		Fall	
System Load Level (MW)	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**
4,847	0.00000015937100	4,307	0.00000000702653	5,470	0.00005286400000	4,323	0.00000001290890
4,843	0.00000015488100	4,307	0.00000001456990	5,467	0.00005044890000	4,319	0.00000000847685
4,827	0.00000013830000	4,305	0.00000000740890	5,467	0.00004816670000	4,317	0.00000000938446
4,826	0.00000013452200	4,305	0.00000000702362	5,462	0.00004896870000	4,316	0.00000000976756
4,826	0.00000013750000	4,304	0.00000001148610	5,462	0.00005161720000	4,311	0.00000000743054
4,824	0.00000013167800	4,303	0.00000000766524	5,459	0.00004622950000	4,310	0.00000000854974
4,821	0.00000013077200	4,300	0.00000001320730	5,457	0.00004704960000	4,310	0.00000000946671
4,819	0.00000012455200	4,298	0.00000001290890	5,453	0.00005010370000	4,310	0.00000000613835
4,818	0.00000012885600	4,282	0.00000000609312	5,453	0.00004674530000	4,307	0.00000000599802
4,815	0.00000012362300	4,281	0.00000000613835	5,449	0.00004620120000	4,307	0.00000000714518
4,809	0.00000012613800	4,279	0.00000001106940	5,449	0.00004434090000	4,304	0.00000000753575
4,806	0.00000011837800	4,273	0.00000000563362	5,447	0.00004621530000	4,303	0.00000000576429
4,802	0.00000011586900	4,268	0.00000001079340	5,446	0.00004512640000	4,301	0.00000000697616
4,802	0.00000011504600	4,265	0.00000000854302	5,444	0.00004699980000	4,300	0.00000000712549
4,791	0.00000010717100	4,265	0.00000000803428	5,438	0.00004430780000	4,297	0.00000000545992
4,784	0.00000010194900	4,263	0.00000001038430	5,436	0.00004308890000	4,294	0.00000000650124
4,781	0.00000010414700	4,261	0.00000000778655	5,429	0.00003899310000	4,290	0.00000000524505
4,781	0.00000009635620	4,258	0.00000000500670	5,428	0.00004060350000	4,288	0.00000000664311
4,781	0.00000009908150	4,254	0.00000000492712	5,422	0.00003830890000	4,286	0.00000000500468
4,778	0.00000009232660	4,254	0.00000000777557	5,422	0.00003946680000	4,281	0.00000000613835
4,777	0.00000009626850	4,252	0.00000000730844	5,422	0.00003988220000	4,280	0.00000000783605
4,777	0.00000009628580	4,240	0.00000000444049	5,422	0.00003897540000	4,279	0.00000000473261
4,774	0.00000009635620	4,239	0.00000000691124	5,421	0.00003786420000	4,274	0.00000000458574

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Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,773	0.00000009352300	4,234	0.00000000664311	5,417	0.00003675930000	4,269	0.00000000558668
4,772	0.00000009352300	4,232	0.00000000416644	5,414	0.00003809030000	4,267	0.00000000433480
4,770	0.00000008715730	4,227	0.00000000628983	5,411	0.00003568430000	4,265	0.00000000549984
4,769	0.00000009154820	4,225	0.00000000748577	5,407	0.00003782980000	4,264	0.00000000420016
4,769	0.00000009024690	4,225	0.00000000393803	5,406	0.00003781870000	4,264	0.00000000614180
4,769	0.00000009154820	4,223	0.00000000736663	5,398	0.00003629550000	4,261	0.00000000410109
4,766	0.00000008893780	4,222	0.00000000719440	5,396	0.00003426310000	4,259	0.00000000493256
4,763	0.00000008584350	4,221	0.00000000604527	5,395	0.00003565760000	4,257	0.00000000528855
4,761	0.00000008521230	4,217	0.00000000563902	5,395	0.00003325010000	4,257	0.00000000648931
4,753	0.00000008040730	4,214	0.00000000360404	5,393	0.00003346900000	4,254	0.00000000390792
4,751	0.00000008396510	4,214	0.00000000533777	5,391	0.00003117310000	4,254	0.00000000393803
4,750	0.00000007926360	4,212	0.00000000349258	5,389	0.00003136180000	4,253	0.00000000504205
4,747	0.00000007814540	4,210	0.00000000369845	5,384	0.00003025070000	4,253	0.00000000390634
4,746	0.00000007700120	4,209	0.00000000325123	5,380	0.00003007690000	4,250	0.00000000619079
4,745	0.00000007644870	4,208	0.00000000517215	5,379	0.00002972770000	4,250	0.00000000760077
4,739	0.00000007375770	4,208	0.00000000343549	5,376	0.00003023680000	4,250	0.00000000748577
4,738	0.00000007434470	4,205	0.00000000634777	5,375	0.00003026470000	4,249	0.00000000369485
4,737	0.00000007268640	4,204	0.00000000620210	5,375	0.00003169170000	4,233	0.00000000332674
4,735	0.00000007114090	4,203	0.00000000312397	5,372	0.00002868070000	4,230	0.00000000409944
4,733	0.00000007012070	4,195	0.00000000330458	5,371	0.00002867630000	4,230	0.00000000397702
4,733	0.00000007012070	4,195	0.00000000306945	5,367	0.00002784130000	4,229	0.00000000309639
4,733	0.00000007375770	4,191	0.00000000568512	5,367	0.00002833120000	4,226	0.00000000440958
4,732	0.00000007321350	4,190	0.00000000327596	5,366	0.00003004510000	4,224	0.00000000309387

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Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,732	0.00000007321350	4,189	0.00000000451484	5,364	0.00002884220000	4,223	0.00000000306945
4,729	0.00000006862380	4,186	0.00000000538187	5,360	0.00002607660000	4,213	0.00000000280886
4,729	0.00000006720150	4,184	0.00000000269997	5,354	0.00002576710000	4,211	0.00000000538187
4,728	0.00000006764020	4,183	0.00000000521511	5,349	0.00002562740000	4,207	0.00000000327562
4,722	0.00000006296280	4,182	0.00000000265544	5,347	0.00002455540000	4,205	0.00000000265268
4,720	0.00000006295130	4,181	0.00000000267683	5,342	0.00002371400000	4,204	0.00000000253034
4,718	0.00000006033870	4,180	0.00000000545686	5,341	0.00002589670000	4,203	0.00000000545793
4,718	0.00000006119580	4,176	0.00000000528855	5,339	0.00002398600000	4,203	0.00000000372444
4,714	0.00000005902430	4,175	0.00000000500930	5,338	0.00002329490000	4,201	0.00000000309890
4,713	0.00000006026040	4,175	0.00000000400648	5,337	0.00002385600000	4,198	0.00000000300089
4,709	0.00000006202370	4,174	0.00000000257079	5,335	0.00002220820000	4,192	0.00000000234417
4,706	0.00000005852740	4,173	0.00000000261042	5,334	0.00002483900000	4,190	0.00000000236184
4,703	0.00000005644770	4,172	0.00000000384969	5,332	0.00002312540000	4,186	0.00000000448287
4,699	0.00000005769710	4,170	0.00000000485139	5,332	0.00002181090000	4,186	0.00000000287666
4,699	0.00000005483690	4,166	0.00000000473968	5,332	0.00002194050000	4,184	0.00000000285394
4,695	0.00000005285330	4,166	0.00000000244703	5,332	0.00002247100000	4,184	0.00000000221153
4,694	0.00000005324030	4,166	0.00000000240822	5,332	0.00002370660000	4,181	0.00000000280625
4,692	0.00000005247390	4,163	0.00000000366708	5,331	0.00002272980000	4,168	0.00000000283108
4,690	0.00000005096350	4,162	0.00000000477119	5,330	0.00002219430000	4,168	0.00000000193166
4,688	0.00000004881210	4,160	0.00000000232452	5,329	0.00002259020000	4,168	0.00000000193166
4,686	0.00000004985020	4,157	0.00000000226625	5,318	0.00002040230000	4,166	0.00000000177439
4,686	0.00000005247390	4,156	0.00000000424029	5,317	0.00002114810000	4,164	0.00000000227097
4,686	0.00000004985020	4,156	0.00000000224743	5,317	0.00002167010000	4,163	0.00000000223311

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,685	0.00000004985020	4,152	0.00000000427020	5,315	0.00002126470000	4,163	0.00000000369767
4,684	0.00000005134680	4,148	0.00000000394553	5,314	0.00001956100000	4,162	0.00000000180668
4,684	0.00000004948660	4,147	0.00000000400732	5,309	0.00002050690000	4,162	0.00000000172473
4,682	0.00000004839580	4,142	0.00000000193286	5,309	0.00002139020000	4,161	0.00000000265402
4,681	0.00000004768020	4,138	0.00000000375695	5,308	0.00001932560000	4,158	0.00000000372521
4,680	0.00000005021400	4,138	0.00000000191593	5,308	0.00002028540000	4,155	0.00000000352406
4,678	0.00000004733750	4,136	0.00000000369690	5,308	0.00002052580000	4,153	0.00000000346570
4,678	0.00000004699220	4,135	0.00000000180777	5,307	0.00002014100000	4,151	0.00000000269862
4,677	0.00000004912160	4,134	0.00000000179245	5,306	0.00002027590000	4,148	0.00000000330389
4,676	0.00000004699220	4,133	0.00000000292542	5,305	0.00001885130000	4,147	0.00000000206934
4,673	0.00000004768020	4,131	0.00000000344174	5,303	0.00001886030000	4,146	0.00000000213861
4,673	0.00000004528540	4,129	0.00000000349502	5,301	0.00001829060000	4,144	0.00000000193379
4,672	0.00000004431670	4,128	0.00000000360623	5,301	0.00001863210000	4,139	0.00000000134024
4,669	0.00000004332280	4,127	0.00000000357695	5,300	0.00001884540000	4,137	0.00000000297587
4,669	0.00000004396130	4,125	0.00000000152493	5,297	0.00001874830000	4,137	0.00000000302383
4,667	0.00000004330640	4,120	0.00000000327799	5,290	0.00001918170000	4,136	0.00000000134928
4,667	0.00000004148310	4,119	0.00000000155467	5,289	0.00001840570000	4,136	0.00000000134928
4,662	0.00000004174460	4,116	0.00000000137727	5,285	0.00001753040000	4,135	0.00000000132501
4,662	0.00000004363690	4,113	0.00000000316887	5,284	0.00001620280000	4,129	0.00000000164378
4,661	0.00000003937970	4,107	0.00000000128236	5,284	0.00001761330000	4,129	0.00000000168403
4,660	0.00000004081990	4,105	0.00000000231131	5,282	0.00001739870000	4,126	0.00000000174497
4,658	0.00000004051870	4,101	0.00000000125062	5,280	0.00001669010000	4,122	0.00000000114607
4,655	0.00000003962310	4,101	0.00000000215897	5,279	0.00001690230000	4,122	0.00000000208925

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,653	0.00000003767240	4,099	0.00000000276429	5,278	0.00001679630000	4,120	0.00000000113426
4,652	0.00000003874490	4,097	0.00000000122337	5,277	0.00001638670000	4,120	0.00000000280625
4,652	0.00000003766500	4,097	0.00000000120667	5,272	0.00001637410000	4,119	0.00000000152176
4,650	0.00000003656970	4,093	0.00000000263363	5,272	0.00001639440000	4,117	0.00000000110125
4,650	0.00000003992280	4,088	0.00000000250758	5,272	0.00001561210000	4,112	0.00000000250704
4,649	0.00000003791770	4,084	0.00000000119437	5,272	0.00001561950000	4,110	0.00000000237149
4,649	0.00000003790370	4,084	0.00000000123265	5,270	0.00001506400000	4,110	0.00000000244753
4,648	0.00000003962310	4,082	0.00000000176968	5,269	0.00001561210000	4,109	0.00000000126402
4,648	0.00000003763000	4,077	0.00000000096544	5,266	0.00001506160000	4,106	0.00000000235195
4,648	0.00000003790370	4,077	0.00000000093506	5,265	0.00001453160000	4,106	0.00000000181047
4,647	0.00000003734890	4,076	0.00000000095783	5,265	0.00001580330000	4,102	0.00000000128094
4,646	0.00000003706790	4,075	0.00000000092721	5,259	0.00001504770000	4,098	0.00000000127591
4,643	0.00000003652110	4,075	0.00000000217813	5,258	0.00001542950000	4,096	0.00000000109523
4,642	0.00000003599150	4,074	0.00000000166697	5,256	0.00001496950000	4,096	0.00000000216006
4,642	0.00000003736270	4,074	0.00000000231082	5,254	0.00001541280000	4,092	0.00000000082493
4,641	0.00000003520730	4,073	0.00000000093423	5,254	0.00001514180000	4,092	0.00000000204939
4,639	0.00000003519410	4,072	0.00000000107304	5,248	0.00001477570000	4,091	0.00000000210549
4,637	0.00000003467730	4,071	0.00000000212468	5,243	0.00001400520000	4,089	0.00000000081114
4,635	0.00000003442400	4,070	0.00000000169571	5,243	0.00001318870000	4,088	0.00000000079165
4,635	0.00000003393280	4,064	0.00000000208792	5,243	0.00001392100000	4,087	0.00000000109237
4,634	0.00000003344330	4,064	0.00000000084312	5,237	0.00001256440000	4,086	0.00000000208705
4,634	0.00000003545670	4,058	0.00000000070761	5,235	0.00001357970000	4,084	0.00000000187022
4,633	0.00000003367440	4,057	0.00000000200015	5,233	0.00001270770000	4,083	0.00000000148329

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,632	0.00000003367440	4,055	0.00000000184027	5,224	0.00001218090000	4,081	0.00000000096060
4,632	0.00000003342450	4,053	0.00000000073420	5,223	0.00001180690000	4,078	0.00000000177013
4,630	0.00000003293260	4,052	0.00000000191349	5,221	0.00001159100000	4,077	0.00000000066861
4,629	0.00000003317590	4,052	0.00000000071952	5,221	0.00001196030000	4,075	0.00000000067372
4,629	0.00000003268900	4,050	0.00000000139067	5,221	0.00001103410000	4,075	0.00000000087737
4,624	0.00000003317590	4,046	0.00000000067944	5,219	0.00001210810000	4,072	0.00000000061580
4,623	0.00000003150360	4,046	0.00000000178756	5,218	0.00001165570000	4,070	0.00000000108394
4,618	0.00000003014560	4,045	0.00000000065764	5,215	0.00001103230000	4,070	0.00000000183658
4,617	0.00000002907340	4,044	0.00000000168188	5,215	0.00001209290000	4,068	0.00000000052844
4,616	0.00000002970070	4,043	0.00000000165266	5,213	0.00001143780000	4,066	0.00000000090032
4,616	0.00000003082800	4,043	0.00000000065737	5,211	0.00001102700000	4,066	0.00000000174497
4,614	0.00000003038170	4,042	0.00000000161339	5,210	0.00001137840000	4,065	0.00000000121295
4,613	0.00000002905700	4,041	0.00000000158708	5,210	0.00001069350000	4,063	0.00000000053907
4,611	0.00000003014560	4,038	0.00000000151622	5,209	0.00001115610000	4,063	0.00000000053907
4,611	0.00000002861940	4,036	0.00000000055396	5,209	0.00001030110000	4,062	0.00000000082469
4,610	0.00000002780870	4,036	0.00000000113869	5,208	0.00001062570000	4,061	0.00000000095826
4,609	0.00000002841140	4,035	0.00000000150313	5,206	0.00001096220000	4,056	0.00000000042714
4,608	0.00000002803720	4,035	0.00000000106286	5,206	0.00001062230000	4,055	0.00000000090032
4,607	0.00000002926610	4,035	0.00000000054653	5,205	0.00000998427000	4,054	0.00000000074892
4,605	0.00000002738450	4,035	0.00000000060363	5,204	0.00001129640000	4,052	0.00000000100206
4,605	0.00000002622520	4,033	0.00000000111522	5,202	0.00001029600000	4,051	0.00000000041056
4,603	0.00000002841140	4,032	0.00000000110603	5,199	0.00001016810000	4,050	0.00000000033802
4,602	0.00000002677850	4,030	0.00000000139372	5,199	0.00001016000000	4,047	0.00000000129199

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,602	0.00000002697680	4,030	0.00000000141576	5,199	0.00001030280000	4,046	0.00000000038005
4,598	0.00000002619020	4,028	0.00000000145186	5,193	0.00000967407000	4,046	0.00000000059347
4,598	0.00000002599180	4,028	0.00000000145145	5,190	0.00001035130000	4,045	0.00000000089473
4,597	0.00000002599180	4,025	0.00000000050067	5,186	0.00001035130000	4,040	0.00000000026284
4,597	0.00000002599180	4,024	0.00000000142507	5,185	0.00000936572000	4,037	0.00000000024332
4,595	0.00000002677850	4,022	0.00000000039304	5,181	0.00000919647000	4,037	0.00000000025765
4,592	0.00000002619020	4,022	0.00000000045550	5,180	0.00000908626000	4,034	0.00000000048546
4,592	0.00000002619020	4,019	0.00000000043135	5,175	0.00000948374000	4,031	0.00000000119339
4,589	0.00000002378450	4,019	0.00000000037720	5,173	0.00000875132000	4,031	0.00000000041337
4,581	0.00000002288940	4,018	0.00000000091743	5,167	0.00000885794000	4,030	0.00000000000000
4,578	0.00000002238820	4,017	0.00000000129934	5,165	0.00000847891000	4,029	0.00000000070288
4,578	0.00000002238400	4,013	0.00000000025814	5,164	0.00000837530000	4,029	0.00000000050554
4,576	0.00000002221620	4,012	0.00000000074827	5,160	0.00000848154000	4,026	0.00000000035675
4,573	0.00000002155640	4,009	0.00000000110846	5,159	0.00000802714000	4,025	0.00000000042979
4,568	0.00000002075330	4,008	0.00000000077667	5,157	0.00000811653000	4,023	0.00000000038706
4,568	0.00000002188440	4,005	0.00000000022526	5,157	0.00000807481000	4,023	0.00000000041056
4,564	0.00000002014020	4,003	0.00000000032832	5,153	0.00000763111000	4,021	0.00000000000000
4,562	0.00000001983650	4,003	0.00000000022514	5,151	0.00000739403000	4,021	0.00000000072234
4,561	0.00000002075330	4,000	0.00000000104442	5,150	0.00000758342000	4,020	0.00000000027061
4,560	0.00000001883940	3,999	0.00000000098179	5,146	0.00000782425000	4,018	0.00000000000000
4,558	0.00000001910390	3,999	0.00000000101689	5,145	0.00000744539000	4,017	0.00000000000000
4,554	0.00000001881390	3,999	0.00000000096082	5,140	0.00000681467000	4,017	0.00000000035401
4,554	0.00000001881390	3,997	0.00000000000000	5,140	0.00000677271000	4,014	0.00000000091719

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Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,553	0.00000001953460	3,993	0.00000000014653	5,140	0.00000698427000	4,014	0.00000000000000
4,553	0.00000001853640	3,993	0.00000000000000	5,138	0.00000664561000	4,011	0.00000000000000
4,551	0.00000001853280	3,991	0.00000000093677	5,137	0.00000685884000	4,009	0.00000000040536
4,551	0.00000001924540	3,989	0.00000000087074	5,136	0.00000677496000	4,007	0.00000000086947
4,551	0.00000001771760	3,989	0.00000000000000	5,134	0.00000664782000	4,006	0.00000000014727
4,549	0.00000001811690	3,988	0.00000000000000	5,132	0.00000672746000	4,006	0.00000000081775
4,549	0.00000001759000	3,988	0.00000000017790	5,132	0.00000693770000	4,001	0.00000000072398
4,549	0.00000001758310	3,985	0.00000000000000	5,130	0.00000677384000	4,000	0.00000000000000
4,549	0.00000001797970	3,983	0.00000000000000	5,129	0.00000681580000	3,999	0.00000000032832
4,549	0.00000001798320	3,982	0.00000000000000	5,128	0.00000669046000	3,995	0.00000000000000
4,547	0.00000001757970	3,981	0.00000000000000	5,126	0.00000647568000	3,995	0.00000000000000
4,546	0.00000001867030	3,980	0.00000000000000	5,122	0.00000596777000	3,994	0.00000000000000
4,546	0.00000001770730	3,979	0.00000000044672	5,121	0.00000616019000	3,991	0.00000000064086
4,540	0.00000001607660	3,978	0.00000000000000	5,119	0.00000623396000	3,990	0.00000000000000
4,540	0.00000001744320	3,978	0.00000000000000	5,118	0.00000589171000	3,990	0.00000000064687
4,539	0.00000001692520	3,976	0.00000000073269	5,118	0.00000600505000	3,989	0.00000000072234
4,538	0.00000001654780	3,973	0.00000000000000	5,118	0.00000596382000	3,988	0.00000000031531
4,537	0.00000001642000	3,973	0.00000000000000	5,117	0.00000600505000	3,988	0.00000000061725
4,536	0.00000001630070	3,971	0.00000000000000	5,114	0.00000603857000	3,988	0.00000000000000
4,536	0.00000001582410	3,970	0.00000000000000	5,113	0.00000567242000	3,984	0.00000000000000
4,534	0.00000001605150	3,964	0.00000000000000	5,111	0.00000600505000	3,984	0.00000000050863
4,533	0.00000001592960	3,963	0.00000000064687	5,110	0.00000570923000	3,983	0.00000000017772
4,532	0.00000001667190	3,962	0.00000000035110	5,109	0.00000553042000	3,981	0.00000000027637

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,530	0.00000001557370	3,961	0.00000000000000	5,108	0.00000567336000	3,980	0.00000000050133
4,528	0.00000001522810	3,955	0.00000000000000	5,106	0.00000567148000	3,979	0.00000000000000
4,528	0.00000001545580	3,954	0.00000000000000	5,106	0.00000552680000	3,977	0.00000000046527
4,527	0.00000001456690	3,954	0.00000000050805	5,105	0.00000607420000	3,977	0.00000000000000
4,526	0.00000001522520	3,953	0.00000000000000	5,103	0.00000571019000	3,976	0.00000000000000
4,526	0.00000001592960	3,953	0.00000000054640	5,102	0.00000549370000	3,976	0.00000000000000
4,526	0.00000001546760	3,952	0.00000000000000	5,101	0.00000560244000	3,975	0.00000000050017
4,519	0.00000001433230	3,950	0.00000000049917	5,101	0.00000567242000	3,974	0.00000000052867
4,519	0.00000001510880	3,950	0.00000000049974	5,098	0.00000522345000	3,973	0.00000000049900
4,517	0.00000001421800	3,950	0.00000000000000	5,097	0.00000525802000	3,972	0.00000000000000
4,517	0.00000001400670	3,946	0.00000000000000	5,097	0.00000560244000	3,970	0.00000000044584
4,514	0.00000001454700	3,946	0.00000000000000	5,096	0.00000522090000	3,970	0.00000000046399
4,513	0.00000001379510	3,945	0.00000000037932	5,093	0.00000509056000	3,970	0.00000000000000
4,512	0.00000001359160	3,943	0.00000000000000	5,092	0.00000515338000	3,969	0.00000000000000
4,512	0.00000001358630	3,943	0.00000000000000	5,091	0.00000525289000	3,967	0.00000000000000
4,511	0.00000001348200	3,942	0.00000000000000	5,090	0.00000532233000	3,966	0.00000000000000
4,511	0.00000001370070	3,941	0.00000000000000	5,088	0.00000508644000	3,965	0.00000000034983
4,505	0.00000001297710	3,939	0.00000000000000	5,085	0.00000490259000	3,965	0.00000000000000
4,504	0.00000001348200	3,938	0.00000000035245	5,082	0.00000505817000	3,965	0.00000000000000
4,503	0.00000001277940	3,938	0.00000000000000	5,079	0.00000505984000	3,962	0.00000000000000
4,503	0.00000001212910	3,935	0.00000000000000	5,078	0.00000490259000	3,959	0.00000000000000
4,503	0.00000001279700	3,934	0.00000000035131	5,077	0.00000486646000	3,956	0.00000000000000
4,500	0.00000001248870	3,933	0.00000000027824	5,076	0.00000442730000	3,955	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,497	0.00000001220540	3,933	0.00000000000000	5,075	0.00000465586000	3,955	0.00000000000000
4,497	0.00000001211240	3,929	0.00000000000000	5,075	0.00000442655000	3,954	0.00000000000000
4,496	0.00000001211240	3,928	0.00000000025552	5,074	0.00000442580000	3,953	0.00000000000000
4,495	0.00000001192610	3,927	0.00000000000000	5,073	0.00000480718000	3,948	0.00000000000000
4,494	0.00000001183450	3,923	0.00000000017922	5,073	0.00000454057000	3,948	0.00000000022384
4,494	0.00000001192610	3,921	0.00000000017493	5,072	0.00000492804000	3,947	0.00000000032910
4,493	0.00000001221020	3,920	0.00000000018558	5,070	0.00000465206000	3,943	0.00000000000000
4,489	0.00000001147540	3,919	0.00000000000000	5,070	0.00000460028000	3,943	0.00000000000000
4,481	0.00000001129780	3,919	0.00000000000000	5,066	0.00000468438000	3,942	0.00000000000000
4,480	0.00000001062200	3,919	0.00000000014533	5,064	0.00000447743000	3,942	0.00000000000000
4,480	0.00000001062000	3,916	0.00000000000000	5,064	0.00000442215000	3,941	0.00000000000000
4,475	0.00000001078700	3,916	0.00000000000000	5,063	0.00000445453000	3,939	0.00000000000000
4,474	0.00000001021530	3,914	0.00000000000000	5,061	0.00000439172000	3,936	0.00000000000000
4,473	0.00000000976216	3,914	0.00000000000000	5,059	0.00000445087000	3,934	0.00000000000000
4,470	0.00000000982864	3,912	0.00000000000000	5,056	0.00000444870000	3,933	0.00000000021647
4,470	0.00000000946251	3,911	0.00000000000000	5,054	0.00000415036000	3,928	0.00000000000000
4,466	0.00000000967531	3,909	0.00000000000000	5,053	0.00000409351000	3,927	0.00000000000000
4,466	0.00000000945313	3,908	0.00000000000000	5,053	0.00000414485000	3,926	0.00000000000000
4,465	0.00000000945313	3,907	0.00000000000000	5,051	0.00000412180000	3,924	0.00000000000000
4,464	0.00000000930899	3,905	0.00000000000000	5,051	0.00000376513000	3,923	0.00000000000000
4,463	0.00000000930716	3,904	0.00000000000000	5,049	0.00000376384000	3,923	0.00000000000000
4,462	0.00000000983055	3,903	0.00000000000000	5,047	0.00000403746000	3,922	0.00000000000000
4,461	0.00000000916537	3,903	0.00000000000000	5,047	0.00000401592000	3,921	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,460	0.00000000889203	3,901	0.00000000000000	5,046	0.00000383736000	3,921	0.00000000000000
4,460	0.00000000909091	3,901	0.00000000000000	5,045	0.00000381220000	3,921	0.00000000000000
4,459	0.00000000916357	3,900	0.00000000000000	5,043	0.00000369156000	3,917	0.00000000000000
4,457	0.00000000924285	3,900	0.00000000000000	5,040	0.00000373666000	3,917	0.00000000000000
4,456	0.00000000861712	3,900	0.00000000000000	5,038	0.00000378733000	3,917	0.00000000000000
4,453	0.00000000861200	3,900	0.00000000000000	5,036	0.00000371070000	3,917	0.00000000000000
4,452	0.00000000861200	3,896	0.00000000000000	5,035	0.00000368599000	3,915	0.00000000000000
4,451	0.00000000854536	3,894	0.00000000000000	5,034	0.00000371381000	3,914	0.00000000000000
4,451	0.00000000804470	3,893	0.00000000000000	5,032	0.00000334830000	3,913	0.00000000000000
4,450	0.00000000835221	3,892	0.00000000000000	5,032	0.00000371256000	3,913	0.00000000000000
4,450	0.00000000810176	3,892	0.00000000000000	5,031	0.00000357389000	3,912	0.00000000000000
4,449	0.00000000822501	3,892	0.00000000000000	5,029	0.00000345635000	3,911	0.00000000000000
4,448	0.00000000828565	3,890	0.00000000000000	5,029	0.00000356851000	3,911	0.00000000000000
4,448	0.00000000828565	3,888	0.00000000000000	5,026	0.00000366205000	3,911	0.00000000000000
4,448	0.00000000822340	3,888	0.00000000000000	5,026	0.00000354761000	3,910	0.00000000000000
4,446	0.00000000822014	3,887	0.00000000000000	5,024	0.00000343172000	3,910	0.00000000000000
4,445	0.00000000791583	3,886	0.00000000000000	5,024	0.00000343634000	3,909	0.00000000000000
4,444	0.00000000803507	3,883	0.00000000000000	5,020	0.00000330245000	3,908	0.00000000000000
4,443	0.00000000803352	3,881	0.00000000000000	5,019	0.00000309693000	3,907	0.00000000000000
4,441	0.00000000773192	3,880	0.00000000000000	5,017	0.00000313734000	3,907	0.00000000000000
4,441	0.00000000784984	3,879	0.00000000000000	5,014	0.00000305493000	3,907	0.00000000000000
4,440	0.00000000778779	3,879	0.00000000000000	5,013	0.00000317854000	3,906	0.00000000000000
4,439	0.00000000767144	3,879	0.00000000000000	5,013	0.00000326252000	3,905	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,438	0.00000000766993	3,879	0.00000000000000	5,013	0.00000317854000	3,904	0.00000000000000
4,438	0.00000000809538	3,879	0.00000000000000	5,012	0.00000303715000	3,903	0.00000000000000
4,438	0.00000000809538	3,877	0.00000000000000	5,011	0.00000305596000	3,902	0.00000000000000
4,436	0.00000000744017	3,871	0.00000000000000	5,007	0.00000307223000	3,898	0.00000000000000
4,434	0.00000000743582	3,869	0.00000000000000	5,006	0.00000293899000	3,898	0.00000000000000
4,434	0.00000000710977	3,869	0.00000000000000	5,005	0.00000303259000	3,896	0.00000000000000
4,433	0.00000000778779	3,868	0.00000000000000	5,004	0.00000315348000	3,895	0.00000000000000
4,432	0.00000000732007	3,867	0.00000000000000	5,001	0.00000295549000	3,893	0.00000000000000
4,431	0.00000000721039	3,867	0.00000000000000	5,001	0.00000293999000	3,892	0.00000000000000
4,431	0.00000000766846	3,865	0.00000000000000	4,998	0.00000291627000	3,892	0.00000000000000
4,430	0.00000000715544	3,863	0.00000000000000	4,997	0.00000303259000	3,891	0.00000000000000
4,429	0.00000000715406	3,863	0.00000000000000	4,997	0.00000291820000	3,888	0.00000000000000
4,427	0.00000000698914	3,862	0.00000000000000	4,995	0.00000264864000	3,888	0.00000000000000
4,424	0.00000000693451	3,859	0.00000000000000	4,993	0.00000270061000	3,886	0.00000000000000
4,422	0.00000000682933	3,859	0.00000000000000	4,993	0.00000286265000	3,886	0.00000000000000
4,422	0.00000000715544	3,856	0.00000000000000	4,990	0.00000289767000	3,886	0.00000000000000
4,421	0.00000000677676	3,855	0.00000000000000	4,989	0.00000271893000	3,885	0.00000000000000
4,420	0.00000000662142	3,853	0.00000000000000	4,985	0.00000269878000	3,885	0.00000000000000
4,419	0.00000000651928	3,852	0.00000000000000	4,982	0.00000241736000	3,885	0.00000000000000
4,417	0.00000000677938	3,851	0.00000000000000	4,981	0.00000275050000	3,885	0.00000000000000
4,415	0.00000000646838	3,851	0.00000000000000	4,978	0.00000235447000	3,884	0.00000000000000
4,415	0.00000000667607	3,851	0.00000000000000	4,976	0.00000240154000	3,883	0.00000000000000
4,413	0.00000000662009	3,849	0.00000000000000	4,973	0.00000244918000	3,883	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,413	0.00000000632036	3,849	0.00000000000000	4,972	0.00000235366000	3,882	0.00000000000000
4,412	0.00000000622297	3,849	0.00000000000000	4,967	0.00000238478000	3,881	0.00000000000000
4,412	0.00000000662009	3,846	0.00000000000000	4,966	0.00000251099000	3,881	0.00000000000000
4,411	0.00000000622174	3,845	0.00000000000000	4,963	0.00000232013000	3,880	0.00000000000000
4,411	0.00000000627085	3,845	0.00000000000000	4,962	0.00000238437000	3,880	0.00000000000000
4,410	0.00000000608289	3,844	0.00000000000000	4,962	0.00000220399000	3,878	0.00000000000000
4,410	0.00000000651800	3,844	0.00000000000000	4,961	0.00000238397000	3,877	0.00000000000000
4,409	0.00000000646838	3,843	0.00000000000000	4,960	0.00000216196000	3,876	0.00000000000000
4,409	0.00000000642031	3,842	0.00000000000000	4,960	0.00000236680000	3,876	0.00000000000000
4,408	0.00000000603232	3,841	0.00000000000000	4,959	0.00000217548000	3,872	0.00000000000000
4,406	0.00000000598516	3,840	0.00000000000000	4,956	0.00000203788000	3,871	0.00000000000000
4,405	0.00000000603829	3,840	0.00000000000000	4,956	0.00000232168000	3,867	0.00000000000000
4,404	0.00000000589143	3,840	0.00000000000000	4,954	0.00000221831000	3,867	0.00000000000000
4,403	0.00000000580245	3,839	0.00000000000000	4,953	0.00000205142000	3,867	0.00000000000000
4,403	0.00000000584559	3,839	0.00000000000000	4,952	0.00000220325000	3,866	0.00000000000000
4,401	0.00000000580017	3,835	0.00000000000000	4,952	0.00000210393000	3,866	0.00000000000000
4,400	0.00000000594009	3,835	0.00000000000000	4,948	0.00000200884000	3,864	0.00000000000000
4,399	0.00000000562423	3,832	0.00000000000000	4,946	0.00000197154000	3,862	0.00000000000000
4,397	0.00000000549314	3,832	0.00000000000000	4,945	0.00000216013000	3,861	0.00000000000000
4,396	0.00000000553481	3,832	0.00000000000000	4,945	0.00000214434000	3,858	0.00000000000000
4,396	0.00000000580017	3,831	0.00000000000000	4,944	0.00000206390000	3,858	0.00000000000000
4,393	0.00000000544841	3,828	0.00000000000000	4,941	0.00000194369000	3,856	0.00000000000000
4,391	0.00000000528040	3,827	0.00000000000000	4,941	0.00000190803000	3,855	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,390	0.00000000532144	3,827	0.00000000000000	4,940	0.00000195574000	3,853	0.00000000000000
4,390	0.00000000545164	3,826	0.00000000000000	4,939	0.00000202298000	3,853	0.00000000000000
4,390	0.00000000532144	3,825	0.00000000000000	4,939	0.00000184541000	3,852	0.00000000000000
4,387	0.00000000515814	3,824	0.00000000000000	4,936	0.00000189275000	3,851	0.00000000000000
4,385	0.00000000511603	3,822	0.00000000000000	4,932	0.00000190703000	3,850	0.00000000000000
4,385	0.00000000511704	3,822	0.00000000000000	4,931	0.00000181889000	3,849	0.00000000000000
4,384	0.00000000507578	3,820	0.00000000000000	4,928	0.00000193027000	3,849	0.00000000000000
4,383	0.00000000499560	3,816	0.00000000000000	4,927	0.00000177158000	3,848	0.00000000000000
4,383	0.00000000496383	3,815	0.00000000000000	4,924	0.00000182042000	3,846	0.00000000000000
4,382	0.00000000491866	3,815	0.00000000000000	4,921	0.00000174836000	3,845	0.00000000000000
4,379	0.00000000515612	3,815	0.00000000000000	4,919	0.00000171628000	3,843	0.00000000000000
4,379	0.00000000484080	3,815	0.00000000000000	4,917	0.00000168079000	3,843	0.00000000000000
4,379	0.00000000484080	3,815	0.00000000000000	4,915	0.00000167966000	3,842	0.00000000000000
4,378	0.00000000465637	3,813	0.00000000000000	4,913	0.00000163787000	3,839	0.00000000000000
4,376	0.00000000480754	3,811	0.00000000000000	4,911	0.00000164628000	3,839	0.00000000000000
4,376	0.00000000472647	3,809	0.00000000000000	4,909	0.00000165874000	3,838	0.00000000000000
4,376	0.00000000468880	3,808	0.00000000000000	4,909	0.00000157294000	3,837	0.00000000000000
4,375	0.00000000461831	3,808	0.00000000000000	4,908	0.00000168108000	3,837	0.00000000000000
4,374	0.00000000480754	3,808	0.00000000000000	4,906	0.00000158415000	3,836	0.00000000000000
4,374	0.00000000491669	3,807	0.00000000000000	4,903	0.00000147193000	3,836	0.00000000000000
4,373	0.00000000461644	3,807	0.00000000000000	4,901	0.00000148136000	3,836	0.00000000000000
4,372	0.00000000465164	3,807	0.00000000000000	4,897	0.00000149934000	3,834	0.00000000000000
4,372	0.00000000454494	3,807	0.00000000000000	4,897	0.00000155093000	3,834	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,372	0.00000000454313	3,806	0.00000000000000	4,895	0.00000148136000	3,833	0.00000000000000
4,371	0.00000000447211	3,805	0.00000000000000	4,894	0.00000146042000	3,832	0.00000000000000
4,370	0.00000000454313	3,802	0.00000000000000	4,890	0.00000144035000	3,831	0.00000000000000
4,370	0.00000000476490	3,800	0.00000000000000	4,890	0.00000149934000	3,830	0.00000000000000
4,369	0.00000000447302	3,797	0.00000000000000	4,890	0.00000148932000	3,825	0.00000000000000
4,369	0.00000000447122	3,797	0.00000000000000	4,889	0.00000144157000	3,819	0.00000000000000
4,368	0.00000000472647	3,795	0.00000000000000	4,888	0.00000147959000	3,819	0.00000000000000
4,367	0.00000000461737	3,795	0.00000000000000	4,888	0.00000142355000	3,818	0.00000000000000
4,365	0.00000000454585	3,794	0.00000000000000	4,885	0.00000143136000	3,816	0.00000000000000
4,364	0.00000000433299	3,794	0.00000000000000	4,885	0.00000137596000	3,816	0.00000000000000
4,363	0.00000000454313	3,792	0.00000000000000	4,883	0.00000132917000	3,815	0.00000000000000
4,363	0.00000000422999	3,791	0.00000000000000	4,883	0.00000134811000	3,813	0.00000000000000
4,361	0.00000000419769	3,791	0.00000000000000	4,883	0.00000124562000	3,813	0.00000000000000
4,360	0.00000000409992	3,791	0.00000000000000	4,879	0.00000132917000	3,813	0.00000000000000
4,356	0.00000000419769	3,790	0.00000000000000	4,877	0.00000129595000	3,812	0.00000000000000
4,355	0.00000000403340	3,790	0.00000000000000	4,876	0.00000130421000	3,812	0.00000000000000
4,355	0.00000000400052	3,789	0.00000000000000	4,874	0.00000127035000	3,809	0.00000000000000
4,355	0.00000000400214	3,788	0.00000000000000	4,873	0.00000122812000	3,809	0.00000000000000
4,353	0.00000000409992	3,786	0.00000000000000	4,872	0.00000126881000	3,805	0.00000000000000
4,352	0.00000000390650	3,786	0.00000000000000	4,872	0.00000130331000	3,805	0.00000000000000
4,351	0.00000000375713	3,786	0.00000000000000	4,871	0.00000118041000	3,804	0.00000000000000
4,350	0.00000000403340	3,785	0.00000000000000	4,865	0.00000117917000	3,804	0.00000000000000
4,350	0.00000000397101	3,784	0.00000000000000	4,864	0.00000135778000	3,803	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,347	0.00000000378439	3,784	0.00000000000000	4,864	0.00000114914000	3,802	0.00000000000000
4,346	0.00000000372415	3,783	0.00000000000000	4,861	0.00000118773000	3,801	0.00000000000000
4,346	0.00000000372415	3,782	0.00000000000000	4,861	0.00000133950000	3,800	0.00000000000000
4,346	0.00000000375408	3,782	0.00000000000000	4,859	0.00000106114000	3,799	0.00000000000000
4,341	0.00000000357989	3,780	0.00000000000000	4,859	0.00000120341000	3,799	0.00000000000000
4,340	0.00000000355062	3,780	0.00000000000000	4,857	0.00000120299000	3,798	0.00000000000000
4,339	0.00000000355062	3,779	0.00000000000000	4,857	0.00000105376000	3,798	0.00000000000000
4,339	0.00000000346926	3,778	0.00000000000000	4,854	0.00000107502000	3,797	0.00000000000000
4,338	0.00000000366674	3,776	0.00000000000000	4,853	0.00000111754000	3,796	0.00000000000000
4,335	0.00000000338619	3,776	0.00000000000000	4,851	0.00000110383000	3,795	0.00000000000000
4,334	0.00000000338619	3,776	0.00000000000000	4,851	0.00000100559000	3,794	0.00000000000000
4,333	0.00000000355062	3,775	0.00000000000000	4,850	0.00000114854000	3,793	0.00000000000000
4,331	0.00000000330633	3,774	0.00000000000000	4,848	0.00000110326000	3,793	0.00000000000000
4,330	0.00000000327952	3,774	0.00000000000000	4,848	0.00000104611000	3,792	0.00000000000000
4,327	0.00000000341325	3,772	0.00000000000000	4,840	0.00000101098000	3,791	0.00000000000000
4,325	0.00000000333196	3,772	0.00000000000000	4,840	0.00000097841700	3,787	0.00000000000000
4,324	0.00000000300221	3,771	0.00000000000000	4,839	0.00000097757000	3,787	0.00000000000000
4,323	0.00000000312674	3,771	0.00000000000000	4,838	0.00000101064000	3,786	0.00000000000000
4,323	0.00000000322955	3,770	0.00000000000000	4,837	0.00000103852000	3,786	0.00000000000000
4,321	0.00000000299975	3,770	0.00000000000000	4,836	0.00000107354000	3,786	0.00000000000000
4,321	0.00000000322826	3,769	0.00000000000000	4,836	0.00000098522500	3,785	0.00000000000000
4,319	0.00000000317676	3,769	0.00000000000000	4,835	0.00000099059000	3,782	0.00000000000000
4,317	0.00000000292855	3,768	0.00000000000000	4,834	0.00000099144000	3,782	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,317	0.00000000297453	3,768	0.00000000000000	4,832	0.00000101734000	3,782	0.00000000000000
4,316	0.00000000295060	3,767	0.00000000000000	4,832	0.00000104523000	3,781	0.00000000000000
4,316	0.00000000292737	3,766	0.00000000000000	4,831	0.00000101734000	3,781	0.00000000000000
4,315	0.00000000288190	3,765	0.00000000000000	4,825	0.00000095791000	3,780	0.00000000000000
4,315	0.00000000290406	3,765	0.00000000000000	4,825	0.00000090070400	3,779	0.00000000000000
4,314	0.00000000290406	3,765	0.00000000000000	4,823	0.00000095758200	3,777	0.00000000000000
4,312	0.00000000299837	3,763	0.00000000000000	4,822	0.00000089603200	3,776	0.00000000000000
4,310	0.00000000295060	3,763	0.00000000000000	4,822	0.00000086551200	3,776	0.00000000000000
4,308	0.00000000276774	3,762	0.00000000000000	4,822	0.00000085410500	3,776	0.00000000000000
4,308	0.00000000290464	3,762	0.00000000000000	4,822	0.00000087643200	3,775	0.00000000000000
4,308	0.00000000272459	3,759	0.00000000000000	4,821	0.00000095106200	3,775	0.00000000000000
4,307	0.00000000260433	3,758	0.00000000000000	4,821	0.00000090180200	3,773	0.00000000000000
4,306	0.00000000264790	3,758	0.00000000000000	4,821	0.00000095171700	3,772	0.00000000000000
4,306	0.00000000272403	3,758	0.00000000000000	4,820	0.00000084256000	3,771	0.00000000000000
4,306	0.00000000269720	3,757	0.00000000000000	4,818	0.00000086597700	3,771	0.00000000000000
4,303	0.00000000251889	3,755	0.00000000000000	4,818	0.00000088241100	3,770	0.00000000000000
4,303	0.00000000269829	3,754	0.00000000000000	4,818	0.00000084166000	3,770	0.00000000000000
4,302	0.00000000249836	3,752	0.00000000000000	4,813	0.00000095890900	3,770	0.00000000000000
4,302	0.00000000264736	3,748	0.00000000000000	4,810	0.00000079667000	3,769	0.00000000000000
4,302	0.00000000260377	3,746	0.00000000000000	4,807	0.00000081845100	3,769	0.00000000000000
4,302	0.00000000274607	3,745	0.00000000000000	4,805	0.00000081902100	3,768	0.00000000000000
4,301	0.00000000249783	3,745	0.00000000000000	4,804	0.00000073960700	3,765	0.00000000000000
4,299	0.00000000253582	3,744	0.00000000000000	4,801	0.00000078111500	3,765	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,297	0.00000000249523	3,744	0.00000000000000	4,799	0.00000077487100	3,763	0.00000000000000
4,296	0.00000000257877	3,743	0.00000000000000	4,798	0.00000080728800	3,763	0.00000000000000
4,296	0.00000000247532	3,743	0.00000000000000	4,797	0.00000087719400	3,761	0.00000000000000
4,296	0.00000000247532	3,742	0.00000000000000	4,795	0.00000075484500	3,760	0.00000000000000
4,295	0.00000000247532	3,739	0.00000000000000	4,795	0.00000074969100	3,760	0.00000000000000
4,295	0.00000000259956	3,737	0.00000000000000	4,790	0.00000068633700	3,758	0.00000000000000
4,294	0.00000000245545	3,736	0.00000000000000	4,789	0.00000071517300	3,758	0.00000000000000
4,293	0.00000000243587	3,736	0.00000000000000	4,788	0.00000066332000	3,758	0.00000000000000
4,293	0.00000000227280	3,735	0.00000000000000	4,785	0.00000064131400	3,757	0.00000000000000
4,292	0.00000000236194	3,733	0.00000000000000	4,783	0.00000069093400	3,757	0.00000000000000
4,291	0.00000000236055	3,730	0.00000000000000	4,782	0.00000071465600	3,756	0.00000000000000
4,290	0.00000000233576	3,727	0.00000000000000	4,782	0.00000063253400	3,753	0.00000000000000
4,289	0.00000000231294	3,727	0.00000000000000	4,782	0.00000070041300	3,753	0.00000000000000
4,288	0.00000000231094	3,726	0.00000000000000	4,781	0.00000069068700	3,751	0.00000000000000
4,287	0.00000000228878	3,724	0.00000000000000	4,780	0.00000064143000	3,749	0.00000000000000
4,287	0.00000000231094	3,723	0.00000000000000	4,779	0.00000067675300	3,748	0.00000000000000
4,287	0.00000000225097	3,723	0.00000000000000	4,779	0.00000064120000	3,748	0.00000000000000
4,287	0.00000000225097	3,722	0.00000000000000	4,779	0.00000065402600	3,748	0.00000000000000
4,286	0.00000000225052	3,722	0.00000000000000	4,777	0.00000061970000	3,747	0.00000000000000
4,286	0.00000000226862	3,721	0.00000000000000	4,775	0.00000065437400	3,746	0.00000000000000
4,284	0.00000000223143	3,721	0.00000000000000	4,771	0.00000066261900	3,746	0.00000000000000
4,284	0.00000000223048	3,721	0.00000000000000	4,770	0.00000065812900	3,744	0.00000000000000
4,282	0.00000000212662	3,720	0.00000000000000	4,770	0.00000064143000	3,743	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,282	0.00000000214316	3,718	0.00000000000000	4,769	0.00000063594200	3,743	0.00000000000000
4,282	0.00000000215927	3,718	0.00000000000000	4,769	0.00000061915500	3,742	0.00000000000000
4,281	0.00000000225147	3,718	0.00000000000000	4,769	0.00000063649100	3,741	0.00000000000000
4,281	0.00000000214545	3,712	0.00000000000000	4,767	0.00000060631700	3,740	0.00000000000000
4,279	0.00000000223048	3,712	0.00000000000000	4,761	0.00000058241900	3,739	0.00000000000000
4,278	0.00000000209721	3,710	0.00000000000000	4,761	0.00000059014000	3,737	0.00000000000000
4,278	0.00000000212487	3,709	0.00000000000000	4,758	0.00000054046600	3,737	0.00000000000000
4,277	0.00000000201799	3,709	0.00000000000000	4,757	0.00000054804700	3,735	0.00000000000000
4,276	0.00000000209896	3,709	0.00000000000000	4,756	0.00000057804500	3,735	0.00000000000000
4,275	0.00000000209852	3,709	0.00000000000000	4,755	0.00000060222300	3,734	0.00000000000000
4,271	0.00000000195676	3,708	0.00000000000000	4,753	0.00000053670300	3,734	0.00000000000000
4,271	0.00000000206886	3,708	0.00000000000000	4,750	0.00000055850100	3,733	0.00000000000000
4,269	0.00000000190800	3,707	0.00000000000000	4,749	0.00000059412900	3,729	0.00000000000000
4,269	0.00000000189276	3,707	0.00000000000000	4,748	0.00000053225000	3,728	0.00000000000000
4,269	0.00000000190800	3,706	0.00000000000000	4,747	0.00000052546700	3,728	0.00000000000000
4,268	0.00000000187810	3,706	0.00000000000000	4,746	0.00000053603800	3,726	0.00000000000000
4,267	0.00000000187771	3,706	0.00000000000000	4,746	0.0000005359440	3,726	0.00000000000000
4,265	0.00000000195676	3,706	0.00000000000000	4,745	0.00000055495500	3,726	0.00000000000000
4,265	0.00000000184723	3,705	0.00000000000000	4,745	0.0000005181430	3,725	0.00000000000000
4,265	0.00000000184723	3,705	0.00000000000000	4,744	0.00000054017400	3,724	0.00000000000000
4,263	0.00000000180069	3,705	0.00000000000000	4,744	0.00000055485900	3,724	0.00000000000000
4,262	0.00000000192368	3,704	0.00000000000000	4,743	0.00000050431400	3,723	0.00000000000000
4,261	0.00000000186299	3,704	0.00000000000000	4,741	0.00000052203800	3,723	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,259	0.00000000170629	3,702	0.00000000000000	4,741	0.00000048027700	3,722	0.00000000000000
4,258	0.00000000167188	3,702	0.00000000000000	4,740	0.00000052930100	3,720	0.00000000000000
4,256	0.00000000165845	3,702	0.00000000000000	4,738	0.00000053594400	3,718	0.00000000000000
4,255	0.00000000166251	3,702	0.00000000000000	4,733	0.00000046719400	3,717	0.00000000000000
4,254	0.00000000164520	3,701	0.00000000000000	4,733	0.00000045735300	3,713	0.00000000000000
4,253	0.00000000163250	3,701	0.00000000000000	4,730	0.00000049025300	3,713	0.00000000000000
4,253	0.00000000172546	3,701	0.00000000000000	4,729	0.00000051076600	3,708	0.00000000000000
4,253	0.00000000161868	3,701	0.00000000000000	4,728	0.00000047627000	3,708	0.00000000000000
4,251	0.00000000157550	3,700	0.00000000000000	4,726	0.00000043551700	3,707	0.00000000000000
4,251	0.00000000160583	3,699	0.00000000000000	4,724	0.00000053998500	3,706	0.00000000000000
4,251	0.00000000160615	3,695	0.00000000000000	4,724	0.00000045752100	3,705	0.00000000000000
4,249	0.00000000153213	3,695	0.00000000000000	4,723	0.00000047967500	3,704	0.00000000000000
4,248	0.00000000153213	3,694	0.00000000000000	4,723	0.00000048294500	3,703	0.00000000000000
4,247	0.00000000155626	3,693	0.00000000000000	4,723	0.00000045678200	3,703	0.00000000000000
4,246	0.00000000149053	3,693	0.00000000000000	4,721	0.00000045360800	3,702	0.00000000000000
4,245	0.00000000160583	3,692	0.00000000000000	4,720	0.00000046382200	3,702	0.00000000000000
4,245	0.00000000147551	3,691	0.00000000000000	4,719	0.00000040351300	3,702	0.00000000000000
4,245	0.00000000159330	3,691	0.00000000000000	4,715	0.00000045710500	3,702	0.00000000000000
4,244	0.00000000141897	3,691	0.00000000000000	4,714	0.00000045360800	3,700	0.00000000000000
4,242	0.00000000144070	3,691	0.00000000000000	4,712	0.00000044453000	3,700	0.00000000000000
4,242	0.00000000155626	3,688	0.00000000000000	4,712	0.00000041132700	3,700	0.00000000000000
4,241	0.00000000142944	3,687	0.00000000000000	4,711	0.00000042600400	3,700	0.00000000000000
4,241	0.00000000153213	3,686	0.00000000000000	4,708	0.00000043202800	3,698	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,241	0.00000000142972	3,686	0.00000000000000	4,707	0.00000038145300	3,697	0.00000000000000
4,240	0.00000000141803	3,686	0.00000000000000	4,707	0.00000040038900	3,697	0.00000000000000
4,239	0.00000000140631	3,686	0.00000000000000	4,703	0.00000037097800	3,697	0.00000000000000
4,238	0.00000000137341	3,685	0.00000000000000	4,702	0.00000039242500	3,697	0.00000000000000
4,235	0.00000000135627	3,685	0.00000000000000	4,699	0.00000038906100	3,695	0.00000000000000
4,235	0.00000000134528	3,682	0.00000000000000	4,697	0.00000038940400	3,694	0.00000000000000
4,232	0.00000000124049	3,682	0.00000000000000	4,697	0.00000037633100	3,693	0.00000000000000
4,232	0.00000000126180	3,681	0.00000000000000	4,696	0.00000035839300	3,693	0.00000000000000
4,232	0.00000000139511	3,681	0.00000000000000	4,694	0.00000035819500	3,693	0.00000000000000
4,231	0.00000000127881	3,679	0.00000000000000	4,689	0.00000034827700	3,692	0.00000000000000
4,230	0.00000000137286	3,679	0.00000000000000	4,688	0.00000035039700	3,691	0.00000000000000
4,230	0.00000000127841	3,678	0.00000000000000	4,686	0.00000040061000	3,690	0.00000000000000
4,230	0.00000000126060	3,678	0.00000000000000	4,684	0.00000035806600	3,689	0.00000000000000
4,230	0.00000000126060	3,677	0.00000000000000	4,683	0.00000032254800	3,688	0.00000000000000
4,228	0.00000000120069	3,677	0.00000000000000	4,682	0.00000034595600	3,686	0.00000000000000
4,227	0.00000000123911	3,677	0.00000000000000	4,680	0.00000034106600	3,686	0.00000000000000
4,226	0.00000000121917	3,677	0.00000000000000	4,679	0.00000033825200	3,686	0.00000000000000
4,223	0.00000000119970	3,676	0.00000000000000	4,679	0.00000033831200	3,686	0.00000000000000
4,222	0.00000000118995	3,676	0.00000000000000	4,679	0.00000033825200	3,684	0.00000000000000
4,222	0.00000000115051	3,675	0.00000000000000	4,677	0.00000032020900	3,684	0.00000000000000
4,221	0.00000000116484	3,675	0.00000000000000	4,675	0.00000030479000	3,684	0.00000000000000
4,220	0.00000000122912	3,674	0.00000000000000	4,675	0.00000035052100	3,683	0.00000000000000
4,219	0.00000000118147	3,673	0.00000000000000	4,675	0.00000034545900	3,682	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,219	0.00000000114975	3,672	0.00000000000000	4,674	0.00000029644700	3,682	0.00000000000000
4,218	0.00000000107383	3,672	0.00000000000000	4,674	0.00000031127600	3,682	0.00000000000000
4,217	0.00000000119970	3,671	0.00000000000000	4,673	0.00000032482900	3,682	0.00000000000000
4,217	0.00000000120942	3,670	0.00000000000000	4,673	0.00000029639000	3,681	0.00000000000000
4,217	0.00000000112548	3,669	0.00000000000000	4,672	0.00000033629100	3,681	0.00000000000000
4,215	0.00000000109202	3,668	0.00000000000000	4,671	0.00000031980600	3,681	0.00000000000000
4,215	0.00000000110003	3,667	0.00000000000000	4,671	0.00000031104700	3,680	0.00000000000000
4,215	0.00000000115051	3,665	0.00000000000000	4,670	0.00000031754900	3,680	0.00000000000000
4,214	0.00000000108951	3,664	0.00000000000000	4,670	0.00000029849800	3,680	0.00000000000000
4,214	0.00000000108080	3,664	0.00000000000000	4,665	0.00000030653400	3,679	0.00000000000000
4,214	0.00000000107261	3,663	0.00000000000000	4,657	0.00000028997100	3,679	0.00000000000000
4,214	0.00000000108951	3,663	0.00000000000000	4,655	0.00000027778700	3,679	0.00000000000000
4,212	0.00000000106366	3,662	0.00000000000000	4,655	0.00000030015600	3,679	0.00000000000000
4,209	0.00000000105477	3,660	0.00000000000000	4,654	0.00000027804700	3,678	0.00000000000000
4,209	0.00000000110003	3,660	0.00000000000000	4,654	0.00000028582800	3,677	0.00000000000000
4,207	0.00000000099790	3,657	0.00000000000000	4,653	0.00000027199600	3,677	0.00000000000000
4,206	0.00000000100576	3,656	0.00000000000000	4,650	0.00000027980900	3,677	0.00000000000000
4,206	0.00000000098181	3,656	0.00000000000000	4,650	0.00000027788900	3,676	0.00000000000000
4,204	0.00000000097328	3,653	0.00000000000000	4,648	0.00000028551600	3,676	0.00000000000000
4,202	0.00000000094483	3,652	0.00000000000000	4,648	0.00000026054100	3,675	0.00000000000000
4,202	0.00000000094435	3,651	0.00000000000000	4,647	0.00000027601300	3,674	0.00000000000000
4,201	0.00000000103765	3,649	0.00000000000000	4,647	0.00000026422300	3,672	0.00000000000000
4,201	0.00000000102088	3,648	0.00000000000000	4,646	0.00000028152800	3,671	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,199	0.00000000093673	3,648	0.00000000000000	4,645	0.00000026441900	3,671	0.00000000000000
4,199	0.00000000093784	3,648	0.00000000000000	4,644	0.00000025891400	3,671	0.00000000000000
4,197	0.00000000088124	3,646	0.00000000000000	4,643	0.00000025487500	3,669	0.00000000000000
4,197	0.00000000091397	3,645	0.00000000000000	4,643	0.00000025323500	3,668	0.00000000000000
4,197	0.00000000096340	3,645	0.00000000000000	4,639	0.00000026782800	3,665	0.00000000000000
4,196	0.00000000090648	3,645	0.00000000000000	4,639	0.00000023944700	3,664	0.00000000000000
4,196	0.00000000090648	3,643	0.00000000000000	4,632	0.00000023090300	3,663	0.00000000000000
4,194	0.00000000089645	3,643	0.00000000000000	4,626	0.00000026802200	3,663	0.00000000000000
4,194	0.00000000086124	3,643	0.00000000000000	4,619	0.00000020761300	3,662	0.00000000000000
4,193	0.00000000080175	3,642	0.00000000000000	4,618	0.00000021340500	3,661	0.00000000000000
4,193	0.00000000084525	3,642	0.00000000000000	4,618	0.00000021950700	3,660	0.00000000000000
4,192	0.00000000086033	3,642	0.00000000000000	4,617	0.00000021529700	3,659	0.00000000000000
4,192	0.00000000086033	3,641	0.00000000000000	4,617	0.00000021798900	3,659	0.00000000000000
4,192	0.00000000082480	3,641	0.00000000000000	4,616	0.00000021822600	3,658	0.00000000000000
4,190	0.00000000083106	3,640	0.00000000000000	4,616	0.00000022144700	3,652	0.00000000000000
4,190	0.00000000082447	3,639	0.00000000000000	4,614	0.00000021371500	3,652	0.00000000000000
4,190	0.00000000086149	3,639	0.00000000000000	4,611	0.00000021505700	3,651	0.00000000000000
4,188	0.00000000081547	3,639	0.00000000000000	4,610	0.00000020483100	3,651	0.00000000000000
4,188	0.00000000090648	3,638	0.00000000000000	4,609	0.00000018802900	3,650	0.00000000000000
4,188	0.00000000089645	3,638	0.00000000000000	4,608	0.00000023917800	3,649	0.00000000000000
4,187	0.00000000078758	3,637	0.00000000000000	4,607	0.00000020475500	3,648	0.00000000000000
4,185	0.00000000079346	3,637	0.00000000000000	4,607	0.00000018540300	3,648	0.00000000000000
4,184	0.00000000078074	3,636	0.00000000000000	4,606	0.00000021191200	3,647	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,183	0.00000000082430	3,636	0.00000000000000	4,605	0.00000019907000	3,647	0.00000000000000
4,180	0.00000000073449	3,636	0.00000000000000	4,605	0.00000021038900	3,647	0.00000000000000
4,179	0.00000000069989	3,636	0.00000000000000	4,604	0.00000021038900	3,647	0.00000000000000
4,179	0.00000000068265	3,635	0.00000000000000	4,604	0.00000019878000	3,646	0.00000000000000
4,178	0.00000000069839	3,634	0.00000000000000	4,604	0.00000020603300	3,646	0.00000000000000
4,177	0.00000000068028	3,634	0.00000000000000	4,603	0.00000019738400	3,646	0.00000000000000
4,177	0.00000000066164	3,633	0.00000000000000	4,601	0.00000018536900	3,645	0.00000000000000
4,176	0.00000000066954	3,633	0.00000000000000	4,599	0.00000020456700	3,645	0.00000000000000
4,176	0.00000000066908	3,632	0.00000000000000	4,596	0.00000019738400	3,645	0.00000000000000
4,176	0.00000000066880	3,632	0.00000000000000	4,596	0.00000020023800	3,643	0.00000000000000
4,174	0.00000000067105	3,632	0.00000000000000	4,595	0.00000017509300	3,643	0.00000000000000
4,172	0.00000000061426	3,630	0.00000000000000	4,595	0.00000022112100	3,642	0.00000000000000
4,172	0.00000000071312	3,630	0.00000000000000	4,594	0.00000019599800	3,642	0.00000000000000
4,168	0.00000000062389	3,629	0.00000000000000	4,594	0.00000020020300	3,641	0.00000000000000
4,167	0.00000000066070	3,629	0.00000000000000	4,594	0.00000018405000	3,640	0.00000000000000
4,166	0.00000000061328	3,628	0.00000000000000	4,593	0.00000021355700	3,640	0.00000000000000
4,166	0.00000000057453	3,627	0.00000000000000	4,590	0.00000017607600	3,640	0.00000000000000
4,165	0.00000000052041	3,627	0.00000000000000	4,589	0.00000018775300	3,640	0.00000000000000
4,164	0.00000000055091	3,627	0.00000000000000	4,587	0.00000016767200	3,640	0.00000000000000
4,164	0.00000000053469	3,627	0.00000000000000	4,584	0.00000017105600	3,640	0.00000000000000
4,164	0.00000000062905	3,625	0.00000000000000	4,582	0.00000015487200	3,640	0.00000000000000
4,163	0.00000000061393	3,624	0.00000000000000	4,580	0.00000016383300	3,639	0.00000000000000
4,163	0.00000000063411	3,622	0.00000000000000	4,576	0.00000016265400	3,637	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,162	0.00000000053370	3,621	0.00000000000000	4,576	0.00000015923200	3,636	0.00000000000000
4,161	0.00000000052493	3,620	0.00000000000000	4,573	0.00000015149500	3,636	0.00000000000000
4,161	0.00000000050869	3,620	0.00000000000000	4,573	0.00000015582100	3,635	0.00000000000000
4,161	0.00000000052938	3,618	0.00000000000000	4,572	0.00000015914500	3,635	0.00000000000000
4,161	0.00000000052493	3,617	0.00000000000000	4,572	0.00000015687700	3,634	0.00000000000000
4,160	0.00000000050869	3,617	0.00000000000000	4,571	0.00000014722400	3,632	0.00000000000000
4,160	0.00000000051802	3,615	0.00000000000000	4,571	0.00000015359900	3,632	0.00000000000000
4,159	0.00000000050827	3,614	0.00000000000000	4,570	0.00000015357100	3,632	0.00000000000000
4,159	0.00000000048366	3,614	0.00000000000000	4,570	0.00000014298100	3,631	0.00000000000000
4,158	0.00000000050186	3,614	0.00000000000000	4,569	0.00000014807300	3,630	0.00000000000000
4,158	0.00000000050145	3,613	0.00000000000000	4,568	0.00000015371400	3,630	0.00000000000000
4,158	0.00000000049098	3,613	0.00000000000000	4,567	0.00000014815600	3,629	0.00000000000000
4,157	0.00000000055147	3,612	0.00000000000000	4,567	0.00000015806600	3,629	0.00000000000000
4,157	0.00000000050145	3,612	0.00000000000000	4,565	0.00000015265400	3,628	0.00000000000000
4,157	0.00000000053370	3,612	0.00000000000000	4,564	0.00000014177400	3,628	0.00000000000000
4,153	0.00000000041943	3,611	0.00000000000000	4,563	0.00000015573600	3,627	0.00000000000000
4,153	0.00000000047335	3,611	0.00000000000000	4,563	0.00000014928300	3,627	0.00000000000000
4,153	0.00000000050827	3,611	0.00000000000000	4,560	0.00000013588000	3,626	0.00000000000000
4,151	0.00000000043930	3,610	0.00000000000000	4,560	0.00000014481800	3,626	0.00000000000000
4,151	0.00000000043930	3,608	0.00000000000000	4,559	0.00000015466700	3,625	0.00000000000000
4,149	0.00000000041781	3,608	0.00000000000000	4,557	0.00000014911800	3,625	0.00000000000000
4,149	0.00000000040183	3,608	0.00000000000000	4,556	0.00000014069000	3,624	0.00000000000000
4,148	0.00000000040174	3,608	0.00000000000000	4,552	0.00000014481800	3,624	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,147	0.00000000048260	3,608	0.00000000000000	4,550	0.00000015478300	3,624	0.00000000000000
4,146	0.00000000039854	3,607	0.00000000000000	4,549	0.00000014069000	3,624	0.00000000000000
4,146	0.00000000039854	3,606	0.00000000000000	4,547	0.00000012797700	3,623	0.00000000000000
4,145	0.00000000036871	3,606	0.00000000000000	4,547	0.00000013764600	3,622	0.00000000000000
4,145	0.00000000036923	3,606	0.00000000000000	4,545	0.00000013090500	3,622	0.00000000000000
4,144	0.00000000035594	3,606	0.00000000000000	4,545	0.00000011914100	3,621	0.00000000000000
4,144	0.00000000036885	3,606	0.00000000000000	4,545	0.00000013565100	3,619	0.00000000000000
4,143	0.00000000035450	3,606	0.00000000000000	4,541	0.00000012346900	3,618	0.00000000000000
4,142	0.00000000040512	3,605	0.00000000000000	4,541	0.00000012162300	3,617	0.00000000000000
4,142	0.00000000034630	3,604	0.00000000000000	4,541	0.00000011574400	3,617	0.00000000000000
4,141	0.00000000036019	3,604	0.00000000000000	4,541	0.00000013172600	3,616	0.00000000000000
4,140	0.00000000035143	3,604	0.00000000000000	4,536	0.00000011819100	3,616	0.00000000000000
4,139	0.00000000038979	3,602	0.00000000000000	4,536	0.00000012160000	3,616	0.00000000000000
4,137	0.00000000033119	3,602	0.00000000000000	4,534	0.00000011649600	3,614	0.00000000000000
4,137	0.00000000024337	3,601	0.00000000000000	4,534	0.00000011324700	3,612	0.00000000000000
4,136	0.00000000025737	3,601	0.00000000000000	4,533	0.00000011473900	3,612	0.00000000000000
4,136	0.00000000029238	3,598	0.00000000000000	4,532	0.00000011660700	3,611	0.00000000000000
4,134	0.00000000025548	3,598	0.00000000000000	4,531	0.00000010681500	3,610	0.00000000000000
4,134	0.00000000025142	3,596	0.00000000000000	4,531	0.00000011725800	3,609	0.00000000000000
4,132	0.00000000024664	3,595	0.00000000000000	4,529	0.00000011816900	3,608	0.00000000000000
4,132	0.00000000022101	3,595	0.00000000000000	4,528	0.00000011816900	3,605	0.00000000000000
4,132	0.00000000024175	3,595	0.00000000000000	4,527	0.00000010832800	3,605	0.00000000000000
4,130	0.00000000029300	3,595	0.00000000000000	4,525	0.00000013275300	3,604	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,128	0.00000000022023	3,593	0.00000000000000	4,525	0.00000011810400	3,603	0.00000000000000
4,125	0.00000000021498	3,593	0.00000000000000	4,525	0.00000011156800	3,601	0.00000000000000
4,125	0.00000000021051	3,592	0.00000000000000	4,523	0.00000010217600	3,601	0.00000000000000
4,124	0.00000000014094	3,591	0.00000000000000	4,523	0.00000010902600	3,600	0.00000000000000
4,122	0.00000000016756	3,590	0.00000000000000	4,520	0.00000010996800	3,600	0.00000000000000
4,122	0.00000000018514	3,589	0.00000000000000	4,519	0.00000012622900	3,599	0.00000000000000
4,121	0.00000000000000	3,589	0.00000000000000	4,518	0.00000010355700	3,598	0.00000000000000
4,121	0.00000000014030	3,588	0.00000000000000	4,513	0.00000010743100	3,598	0.00000000000000
4,120	0.00000000021494	3,584	0.00000000000000	4,512	0.00000009291980	3,598	0.00000000000000
4,119	0.00000000013916	3,583	0.00000000000000	4,511	0.00000009986670	3,597	0.00000000000000
4,119	0.00000000016535	3,582	0.00000000000000	4,510	0.00000010586800	3,597	0.00000000000000
4,118	0.00000000013916	3,582	0.00000000000000	4,509	0.00000009632560	3,597	0.00000000000000
4,117	0.00000000020586	3,582	0.00000000000000	4,508	0.00000010433900	3,596	0.00000000000000
4,117	0.00000000000000	3,582	0.00000000000000	4,507	0.00000009215740	3,594	0.00000000000000
4,116	0.00000000000000	3,581	0.00000000000000	4,504	0.00000009912020	3,594	0.00000000000000
4,115	0.00000000000000	3,581	0.00000000000000	4,503	0.00000009566760	3,594	0.00000000000000
4,115	0.00000000000000	3,581	0.00000000000000	4,502	0.00000009215740	3,593	0.00000000000000
4,114	0.00000000000000	3,580	0.00000000000000	4,502	0.00000009418080	3,592	0.00000000000000
4,112	0.00000000000000	3,580	0.00000000000000	4,498	0.00000009276180	3,591	0.00000000000000
4,112	0.00000000000000	3,579	0.00000000000000	4,494	0.00000008941920	3,588	0.00000000000000
4,109	0.00000000000000	3,579	0.00000000000000	4,494	0.00000009081090	3,588	0.00000000000000
4,109	0.00000000000000	3,579	0.00000000000000	4,491	0.00000008259390	3,587	0.00000000000000
4,109	0.00000000000000	3,579	0.00000000000000	4,490	0.00000008430420	3,587	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,109	0.00000000000000	3,579	0.00000000000000	4,488	0.00000010061500	3,586	0.00000000000000
4,108	0.00000000000000	3,578	0.00000000000000	4,488	0.00000008507510	3,585	0.00000000000000
4,107	0.00000000000000	3,578	0.00000000000000	4,487	0.00000007902530	3,584	0.00000000000000
4,104	0.00000000000000	3,577	0.00000000000000	4,485	0.00000008368660	3,584	0.00000000000000
4,103	0.00000000000000	3,577	0.00000000000000	4,483	0.00000008075040	3,583	0.00000000000000
4,102	0.00000000000000	3,576	0.00000000000000	4,483	0.00000009358510	3,583	0.00000000000000
4,102	0.00000000000000	3,576	0.00000000000000	4,480	0.00000007349370	3,581	0.00000000000000
4,100	0.00000000000000	3,576	0.00000000000000	4,477	0.00000007893700	3,580	0.00000000000000
4,100	0.00000000000000	3,576	0.00000000000000	4,476	0.00000007402420	3,580	0.00000000000000
4,099	0.00000000000000	3,575	0.00000000000000	4,474	0.00000008128620	3,579	0.00000000000000
4,099	0.00000000000000	3,573	0.00000000000000	4,473	0.00000008307870	3,579	0.00000000000000
4,097	0.00000000000000	3,572	0.00000000000000	4,471	0.00000007084290	3,578	0.00000000000000
4,097	0.00000000000000	3,570	0.00000000000000	4,471	0.00000007552950	3,576	0.00000000000000
4,095	0.00000000000000	3,569	0.00000000000000	4,470	0.00000008629100	3,576	0.00000000000000
4,093	0.00000000000000	3,569	0.00000000000000	4,470	0.00000007284510	3,575	0.00000000000000
4,092	0.00000000000000	3,568	0.00000000000000	4,469	0.00000007499320	3,574	0.00000000000000
4,092	0.00000000000000	3,567	0.00000000000000	4,469	0.00000007347920	3,574	0.00000000000000
4,091	0.00000000000000	3,566	0.00000000000000	4,469	0.00000008941920	3,574	0.00000000000000
4,090	0.00000000000000	3,566	0.00000000000000	4,463	0.00000007023790	3,574	0.00000000000000
4,090	0.00000000000000	3,565	0.00000000000000	4,461	0.00000008079630	3,573	0.00000000000000
4,087	0.00000000000000	3,565	0.00000000000000	4,460	0.00000007181420	3,573	0.00000000000000
4,087	0.00000000000000	3,564	0.00000000000000	4,460	0.00000006720850	3,572	0.00000000000000
4,087	0.00000000000000	3,564	0.00000000000000	4,458	0.00000006877320	3,571	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,085	0.00000000000000	3,563	0.00000000000000	4,457	0.00000006295060	3,571	0.00000000000000
4,084	0.00000000000000	3,563	0.00000000000000	4,453	0.00000006682330	3,570	0.00000000000000
4,081	0.00000000000000	3,562	0.00000000000000	4,453	0.0000006380160	3,570	0.00000000000000
4,080	0.00000000000000	3,562	0.00000000000000	4,452	0.00000006023820	3,570	0.00000000000000
4,080	0.00000000000000	3,562	0.00000000000000	4,452	0.00000006572400	3,570	0.00000000000000
4,080	0.00000000000000	3,561	0.00000000000000	4,450	0.00000006475210	3,570	0.00000000000000
4,080	0.00000000000000	3,561	0.00000000000000	4,449	0.00000006769450	3,569	0.00000000000000
4,079	0.00000000000000	3,561	0.00000000000000	4,448	0.00000006769450	3,568	0.00000000000000
4,078	0.00000000000000	3,561	0.00000000000000	4,448	0.00000006114890	3,567	0.00000000000000
4,078	0.00000000000000	3,560	0.00000000000000	4,447	0.0000006251140	3,567	0.00000000000000
4,077	0.00000000000000	3,560	0.00000000000000	4,447	0.00000006671010	3,566	0.00000000000000
4,076	0.00000000000000	3,560	0.00000000000000	4,447	0.00000006332680	3,566	0.00000000000000
4,076	0.00000000000000	3,560	0.00000000000000	4,447	0.00000006436850	3,566	0.00000000000000
4,075	0.00000000000000	3,560	0.00000000000000	4,446	0.00000005972700	3,565	0.00000000000000
4,075	0.00000000000000	3,557	0.00000000000000	4,445	0.00000005675800	3,564	0.00000000000000
4,074	0.00000000000000	3,557	0.00000000000000	4,445	0.00000006107890	3,563	0.00000000000000
4,074	0.00000000000000	3,556	0.00000000000000	4,443	0.0000006157200	3,563	0.00000000000000
4,074	0.00000000000000	3,556	0.00000000000000	4,443	0.00000006067530	3,561	0.00000000000000
4,073	0.00000000000000	3,556	0.00000000000000	4,441	0.0000005801050	3,560	0.00000000000000
4,070	0.00000000000000	3,553	0.00000000000000	4,437	0.0000005803280	3,560	0.00000000000000
4,070	0.00000000000000	3,552	0.00000000000000	4,437	0.00000005838790	3,559	0.00000000000000
4,070	0.00000000000000	3,552	0.00000000000000	4,435	0.00000005628310	3,558	0.00000000000000
4,065	0.00000000000000	3,551	0.00000000000000	4,434	0.00000006059520	3,558	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,065	0.00000000000000	3,551	0.00000000000000	4,434	0.00000006869490	3,558	0.00000000000000
4,065	0.00000000000000	3,551	0.00000000000000	4,432	0.00000005665960	3,556	0.00000000000000
4,064	0.00000000000000	3,550	0.00000000000000	4,432	0.00000006818040	3,556	0.00000000000000
4,063	0.00000000000000	3,550	0.00000000000000	4,429	0.00000006480100	3,554	0.00000000000000
4,063	0.00000000000000	3,550	0.00000000000000	4,428	0.00000005714450	3,553	0.00000000000000
4,061	0.00000000000000	3,549	0.00000000000000	4,428	0.00000005751550	3,553	0.00000000000000
4,060	0.00000000000000	3,549	0.00000000000000	4,426	0.00000005627240	3,553	0.00000000000000
4,057	0.00000000000000	3,549	0.00000000000000	4,426	0.00000005344190	3,552	0.00000000000000
4,056	0.00000000000000	3,549	0.00000000000000	4,426	0.00000006337460	3,552	0.00000000000000
4,056	0.00000000000000	3,548	0.00000000000000	4,426	0.00000005589670	3,552	0.00000000000000
4,053	0.00000000000000	3,548	0.00000000000000	4,425	0.00000005221920	3,552	0.00000000000000
4,053	0.00000000000000	3,547	0.00000000000000	4,425	0.00000005107860	3,552	0.00000000000000
4,051	0.00000000000000	3,546	0.00000000000000	4,425	0.00000005220910	3,552	0.00000000000000
4,051	0.00000000000000	3,546	0.00000000000000	4,424	0.00000005106840	3,551	0.00000000000000
4,051	0.00000000000000	3,545	0.00000000000000	4,423	0.00000005502650	3,551	0.00000000000000
4,050	0.00000000000000	3,545	0.00000000000000	4,423	0.00000005420290	3,551	0.00000000000000
4,050	0.00000000000000	3,545	0.00000000000000	4,420	0.00000005932200	3,547	0.00000000000000
4,050	0.00000000000000	3,544	0.00000000000000	4,420	0.00000004986890	3,547	0.00000000000000
4,049	0.00000000000000	3,544	0.00000000000000	4,419	0.00000005188060	3,547	0.00000000000000
4,049	0.00000000000000	3,544	0.00000000000000	4,419	0.00000005139870	3,547	0.00000000000000
4,049	0.00000000000000	3,544	0.00000000000000	4,418	0.00000005302740	3,546	0.00000000000000
4,049	0.00000000000000	3,544	0.00000000000000	4,417	0.00000005458710	3,546	0.00000000000000
4,048	0.00000000000000	3,543	0.00000000000000	4,414	0.00000005103890	3,546	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,048	0.00000000000000	3,542	0.00000000000000	4,414	0.00000005028540	3,546	0.00000000000000
4,048	0.00000000000000	3,542	0.00000000000000	4,413	0.00000005102920	3,545	0.00000000000000
4,048	0.00000000000000	3,541	0.00000000000000	4,413	0.00000005177950	3,545	0.00000000000000
4,048	0.00000000000000	3,541	0.00000000000000	4,412	0.00000004459960	3,544	0.00000000000000
4,047	0.00000000000000	3,540	0.00000000000000	4,408	0.0000004806790	3,544	0.00000000000000
4,047	0.00000000000000	3,539	0.00000000000000	4,408	0.00000004842110	3,543	0.00000000000000
4,045	0.00000000000000	3,539	0.00000000000000	4,406	0.00000004328190	3,543	0.00000000000000
4,045	0.00000000000000	3,538	0.00000000000000	4,406	0.00000004626560	3,543	0.00000000000000
4,041	0.00000000000000	3,538	0.00000000000000	4,402	0.00000004522500	3,543	0.00000000000000
4,040	0.00000000000000	3,537	0.00000000000000	4,401	0.0000004233910	3,542	0.00000000000000
4,039	0.00000000000000	3,536	0.00000000000000	4,399	0.0000004802170	3,541	0.00000000000000
4,039	0.00000000000000	3,535	0.00000000000000	4,399	0.00000004595130	3,539	0.00000000000000
4,038	0.00000000000000	3,535	0.00000000000000	4,396	0.00000004360540	3,538	0.00000000000000
4,038	0.00000000000000	3,535	0.00000000000000	4,396	0.00000004077090	3,538	0.00000000000000
4,037	0.00000000000000	3,534	0.00000000000000	4,396	0.00000004992640	3,537	0.00000000000000
4,037	0.00000000000000	3,533	0.00000000000000	4,390	0.00000003899910	3,537	0.00000000000000
4,036	0.00000000000000	3,532	0.00000000000000	4,389	0.0000004323230	3,535	0.00000000000000
4,036	0.00000000000000	3,531	0.00000000000000	4,388	0.00000004040860	3,535	0.00000000000000
4,036	0.00000000000000	3,531	0.00000000000000	4,385	0.00000003923610	3,535	0.00000000000000
4,036	0.00000000000000	3,531	0.00000000000000	4,384	0.00000003981330	3,534	0.00000000000000
4,035	0.00000000000000	3,530	0.00000000000000	4,384	0.0000003835160	3,533	0.00000000000000
4,034	0.00000000000000	3,528	0.00000000000000	4,384	0.0000003810490	3,533	0.00000000000000
4,031	0.00000000000000	3,528	0.00000000000000	4,383	0.00000003956150	3,531	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,031	0.00000000000000	3,528	0.00000000000000	4,383	0.00000004043160	3,530	0.00000000000000
4,031	0.00000000000000	3,528	0.00000000000000	4,380	0.00000003780110	3,530	0.00000000000000
4,029	0.00000000000000	3,527	0.00000000000000	4,380	0.00000004040860	3,530	0.00000000000000
4,029	0.00000000000000	3,527	0.00000000000000	4,378	0.00000003754940	3,529	0.00000000000000
4,028	0.00000000000000	3,525	0.00000000000000	4,376	0.00000003672680	3,527	0.00000000000000
4,027	0.00000000000000	3,524	0.00000000000000	4,375	0.00000003893140	3,527	0.00000000000000
4,026	0.00000000000000	3,524	0.00000000000000	4,374	0.00000003355960	3,525	0.00000000000000
4,026	0.00000000000000	3,524	0.00000000000000	4,374	0.00000003587670	3,523	0.00000000000000
4,026	0.00000000000000	3,524	0.00000000000000	4,373	0.00000003666290	3,522	0.00000000000000
4,026	0.00000000000000	3,523	0.00000000000000	4,373	0.00000003670510	3,519	0.00000000000000
4,024	0.00000000000000	3,522	0.00000000000000	4,370	0.00000003485730	3,518	0.00000000000000
4,023	0.00000000000000	3,522	0.00000000000000	4,368	0.00000003694160	3,518	0.00000000000000
4,019	0.00000000000000	3,522	0.00000000000000	4,366	0.00000003613100	3,518	0.00000000000000
4,019	0.00000000000000	3,522	0.00000000000000	4,365	0.00000003352660	3,518	0.00000000000000
4,019	0.00000000000000	3,521	0.00000000000000	4,364	0.00000003256080	3,517	0.00000000000000
4,018	0.00000000000000	3,521	0.00000000000000	4,363	0.00000003532750	3,516	0.00000000000000
4,018	0.00000000000000	3,520	0.00000000000000	4,362	0.00000003279250	3,515	0.00000000000000
4,018	0.00000000000000	3,520	0.00000000000000	4,361	0.00000003534080	3,515	0.00000000000000
4,016	0.00000000000000	3,520	0.00000000000000	4,359	0.00000003276720	3,515	0.00000000000000
4,016	0.00000000000000	3,520	0.00000000000000	4,351	0.00000002991000	3,515	0.00000000000000
4,015	0.00000000000000	3,519	0.00000000000000	4,350	0.00000003133190	3,515	0.00000000000000
4,014	0.00000000000000	3,519	0.00000000000000	4,350	0.00000003156680	3,514	0.00000000000000
4,014	0.00000000000000	3,519	0.00000000000000	4,348	0.00000003036860	3,514	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
4,013	0.00000000000000	3,518	0.00000000000000	4,348	0.00000003432630	3,514	0.00000000000000
4,012	0.00000000000000	3,518	0.00000000000000	4,346	0.00000002968610	3,514	0.00000000000000
4,012	0.00000000000000	3,518	0.00000000000000	4,344	0.00000003178830	3,513	0.00000000000000
4,011	0.00000000000000	3,518	0.00000000000000	4,343	0.00000002923520	3,512	0.00000000000000
4,011	0.00000000000000	3,517	0.00000000000000	4,342	0.00000002692390	3,511	0.00000000000000
4,010	0.00000000000000	3,517	0.00000000000000	4,341	0.00000002879050	3,511	0.00000000000000
4,010	0.00000000000000	3,516	0.00000000000000	4,338	0.00000002550470	3,510	0.00000000000000
4,010	0.00000000000000	3,516	0.00000000000000	4,338	0.00000002630100	3,510	0.00000000000000
4,009	0.00000000000000	3,516	0.00000000000000	4,337	0.00000002753700	3,510	0.00000000000000
4,009	0.00000000000000	3,516	0.00000000000000	4,336	0.00000002667070	3,508	0.00000000000000
4,009	0.00000000000000	3,515	0.00000000000000	4,334	0.00000002857080	3,508	0.00000000000000
4,007	0.00000000000000	3,515	0.00000000000000	4,334	0.00000002531350	3,506	0.00000000000000
4,007	0.00000000000000	3,514	0.00000000000000	4,334	0.00000002946000	3,506	0.00000000000000
4,004	0.00000000000000	3,513	0.00000000000000	4,334	0.00000002510440	3,505	0.00000000000000
4,004	0.00000000000000	3,512	0.00000000000000	4,333	0.00000002687600	3,504	0.00000000000000
4,002	0.00000000000000	3,512	0.00000000000000	4,333	0.00000002473180	3,502	0.00000000000000
4,002	0.00000000000000	3,511	0.00000000000000	4,332	0.00000002670730	3,502	0.00000000000000
3,999	0.00000000000000	3,510	0.00000000000000	4,330	0.00000002548930	3,502	0.00000000000000
3,999	0.00000000000000	3,510	0.00000000000000	4,328	0.00000003039210	3,501	0.00000000000000
3,997	0.00000000000000	3,508	0.00000000000000	4,327	0.00000002508940	3,500	0.00000000000000
3,997	0.00000000000000	3,508	0.00000000000000	4,325	0.00000002492620	3,500	0.00000000000000
3,996	0.00000000000000	3,508	0.00000000000000	4,324	0.00000002646430	3,500	0.00000000000000
3,996	0.00000000000000	3,508	0.00000000000000	4,324	0.00000002646430	3,500	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,994	0.00000000000000	3,507	0.00000000000000	4,324	0.00000002507480	3,500	0.00000000000000
3,993	0.00000000000000	3,506	0.00000000000000	4,322	0.00000002395280	3,499	0.00000000000000
3,992	0.00000000000000	3,505	0.00000000000000	4,322	0.00000002326840	3,498	0.00000000000000
3,991	0.00000000000000	3,505	0.00000000000000	4,321	0.00000002433160	3,498	0.00000000000000
3,989	0.00000000000000	3,505	0.00000000000000	4,321	0.00000002968610	3,498	0.00000000000000
3,988	0.00000000000000	3,504	0.00000000000000	4,321	0.00000002239760	3,498	0.00000000000000
3,988	0.00000000000000	3,504	0.00000000000000	4,318	0.00000002322690	3,498	0.00000000000000
3,988	0.00000000000000	3,504	0.00000000000000	4,318	0.00000002507960	3,498	0.00000000000000
3,988	0.00000000000000	3,503	0.00000000000000	4,317	0.00000002305010	3,498	0.00000000000000
3,987	0.00000000000000	3,503	0.00000000000000	4,316	0.00000002418120	3,496	0.00000000000000
3,986	0.00000000000000	3,500	0.00000000000000	4,316	0.00000002139340	3,494	0.00000000000000
3,985	0.00000000000000	3,499	0.00000000000000	4,314	0.00000002270270	3,494	0.00000000000000
3,985	0.00000000000000	3,499	0.00000000000000	4,313	0.00000002305010	3,493	0.00000000000000
3,984	0.00000000000000	3,498	0.00000000000000	4,311	0.00000002202260	3,492	0.00000000000000
3,981	0.00000000000000	3,498	0.00000000000000	4,310	0.00000002668620	3,491	0.00000000000000
3,981	0.00000000000000	3,497	0.00000000000000	4,310	0.00000002253170	3,490	0.00000000000000
3,978	0.00000000000000	3,497	0.00000000000000	4,310	0.00000002451190	3,490	0.00000000000000
3,978	0.00000000000000	3,497	0.00000000000000	4,306	0.00000002305450	3,490	0.00000000000000
3,977	0.00000000000000	3,497	0.00000000000000	4,305	0.00000002058660	3,490	0.00000000000000
3,977	0.00000000000000	3,496	0.00000000000000	4,304	0.00000002253600	3,489	0.00000000000000
3,976	0.00000000000000	3,495	0.00000000000000	4,303	0.00000002253170	3,488	0.00000000000000
3,976	0.00000000000000	3,495	0.00000000000000	4,302	0.00000002088310	3,487	0.00000000000000
3,976	0.00000000000000	3,495	0.00000000000000	4,302	0.00000002119300	3,487	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,972	0.00000000000000	3,495	0.00000000000000	4,301	0.00000001967620	3,486	0.00000000000000
3,972	0.00000000000000	3,495	0.00000000000000	4,301	0.00000002071920	3,486	0.00000000000000
3,967	0.00000000000000	3,494	0.00000000000000	4,300	0.00000002185640	3,485	0.00000000000000
3,966	0.00000000000000	3,494	0.00000000000000	4,298	0.00000002168500	3,485	0.00000000000000
3,965	0.00000000000000	3,490	0.00000000000000	4,298	0.00000002040830	3,484	0.00000000000000
3,964	0.00000000000000	3,489	0.00000000000000	4,298	0.00000002152210	3,483	0.00000000000000
3,961	0.00000000000000	3,488	0.00000000000000	4,295	0.00000001891400	3,482	0.00000000000000
3,960	0.00000000000000	3,488	0.00000000000000	4,290	0.00000002102910	3,481	0.00000000000000
3,960	0.00000000000000	3,488	0.00000000000000	4,289	0.00000001794380	3,481	0.00000000000000
3,959	0.00000000000000	3,488	0.00000000000000	4,288	0.00000001847640	3,480	0.00000000000000
3,959	0.00000000000000	3,486	0.00000000000000	4,288	0.00000001794380	3,479	0.00000000000000
3,957	0.00000000000000	3,486	0.00000000000000	4,286	0.00000002270270	3,479	0.00000000000000
3,957	0.00000000000000	3,486	0.00000000000000	4,285	0.00000001950530	3,479	0.00000000000000
3,957	0.00000000000000	3,485	0.00000000000000	4,283	0.00000001933650	3,479	0.00000000000000
3,956	0.00000000000000	3,485	0.00000000000000	4,283	0.00000001933650	3,477	0.00000000000000
3,956	0.00000000000000	3,484	0.00000000000000	4,281	0.00000001751710	3,476	0.00000000000000
3,955	0.00000000000000	3,484	0.00000000000000	4,274	0.00000001805110	3,476	0.00000000000000
3,955	0.00000000000000	3,484	0.00000000000000	4,274	0.00000001805110	3,476	0.00000000000000
3,955	0.00000000000000	3,483	0.00000000000000	4,274	0.00000001609560	3,475	0.00000000000000
3,954	0.00000000000000	3,482	0.00000000000000	4,272	0.00000001573390	3,475	0.00000000000000
3,953	0.00000000000000	3,481	0.00000000000000	4,272	0.00000002010510	3,475	0.00000000000000
3,952	0.00000000000000	3,480	0.00000000000000	4,271	0.00000001751710	3,475	0.00000000000000
3,951	0.00000000000000	3,480	0.00000000000000	4,271	0.00000001893320	3,475	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,951	0.00000000000000	3,478	0.00000000000000	4,271	0.00000001763380	3,474	0.00000000000000
3,950	0.00000000000000	3,478	0.00000000000000	4,269	0.00000001737030	3,470	0.00000000000000
3,949	0.00000000000000	3,478	0.00000000000000	4,269	0.00000001698080	3,470	0.00000000000000
3,949	0.00000000000000	3,476	0.00000000000000	4,265	0.00000001684290	3,468	0.00000000000000
3,949	0.00000000000000	3,476	0.00000000000000	4,264	0.00000001584500	3,468	0.00000000000000
3,949	0.00000000000000	3,476	0.00000000000000	4,262	0.00000001536760	3,468	0.00000000000000
3,947	0.00000000000000	3,476	0.00000000000000	4,261	0.00000001619930	3,467	0.00000000000000
3,946	0.00000000000000	3,474	0.00000000000000	4,259	0.00000001658550	3,467	0.00000000000000
3,946	0.00000000000000	3,473	0.00000000000000	4,259	0.00000001594520	3,465	0.00000000000000
3,944	0.00000000000000	3,472	0.00000000000000	4,257	0.00000001523720	3,464	0.00000000000000
3,942	0.00000000000000	3,471	0.00000000000000	4,257	0.00000001498700	3,464	0.00000000000000
3,942	0.00000000000000	3,470	0.00000000000000	4,256	0.00000001488870	3,462	0.00000000000000
3,942	0.00000000000000	3,470	0.00000000000000	4,255	0.00000001430980	3,462	0.00000000000000
3,940	0.00000000000000	3,470	0.00000000000000	4,254	0.00000001686610	3,462	0.00000000000000
3,940	0.00000000000000	3,469	0.00000000000000	4,253	0.00000001430690	3,461	0.00000000000000
3,939	0.00000000000000	3,469	0.00000000000000	4,252	0.00000001440900	3,461	0.00000000000000
3,939	0.00000000000000	3,467	0.00000000000000	4,252	0.00000001487970	3,460	0.00000000000000
3,938	0.00000000000000	3,466	0.00000000000000	4,246	0.00000001294100	3,460	0.00000000000000
3,938	0.00000000000000	3,466	0.00000000000000	4,246	0.00000001375150	3,459	0.00000000000000
3,938	0.00000000000000	3,466	0.00000000000000	4,242	0.00000001313910	3,459	0.00000000000000
3,937	0.00000000000000	3,465	0.00000000000000	4,241	0.00000001253720	3,458	0.00000000000000
3,937	0.00000000000000	3,465	0.00000000000000	4,241	0.00000001440900	3,457	0.00000000000000
3,936	0.00000000000000	3,465	0.00000000000000	4,239	0.00000001355190	3,456	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,936	0.00000000000000	3,464	0.00000000000000	4,238	0.00000001233940	3,456	0.00000000000000
3,936	0.00000000000000	3,464	0.00000000000000	4,238	0.00000001364460	3,454	0.00000000000000
3,936	0.00000000000000	3,463	0.00000000000000	4,236	0.0000001303870	3,453	0.00000000000000
3,936	0.00000000000000	3,463	0.00000000000000	4,234	0.0000001274350	3,451	0.00000000000000
3,934	0.00000000000000	3,461	0.00000000000000	4,233	0.0000001242180	3,451	0.00000000000000
3,933	0.00000000000000	3,461	0.00000000000000	4,231	0.0000001281820	3,450	0.00000000000000
3,933	0.00000000000000	3,460	0.00000000000000	4,231	0.00000001409960	3,450	0.00000000000000
3,933	0.00000000000000	3,460	0.00000000000000	4,229	0.0000001271770	3,450	0.00000000000000
3,933	0.00000000000000	3,459	0.00000000000000	4,229	0.0000001302010	3,449	0.00000000000000
3,932	0.00000000000000	3,459	0.00000000000000	4,228	0.0000001187040	3,449	0.00000000000000
3,932	0.00000000000000	3,457	0.00000000000000	4,227	0.00000001261920	3,448	0.00000000000000
3,931	0.00000000000000	3,456	0.00000000000000	4,226	0.00000001252710	3,447	0.00000000000000
3,931	0.00000000000000	3,456	0.00000000000000	4,225	0.00000001149410	3,447	0.00000000000000
3,930	0.00000000000000	3,456	0.00000000000000	4,224	0.0000001222720	3,447	0.00000000000000
3,929	0.00000000000000	3,454	0.00000000000000	4,224	0.0000001158030	3,447	0.00000000000000
3,929	0.00000000000000	3,454	0.00000000000000	4,222	0.00000001130940	3,447	0.00000000000000
3,929	0.00000000000000	3,454	0.00000000000000	4,213	0.0000001064100	3,447	0.00000000000000
3,928	0.00000000000000	3,452	0.00000000000000	4,211	0.00000001046040	3,446	0.00000000000000
3,928	0.00000000000000	3,452	0.00000000000000	4,211	0.00000001096070	3,445	0.00000000000000
3,928	0.00000000000000	3,452	0.00000000000000	4,210	0.0000001187280	3,444	0.00000000000000
3,928	0.00000000000000	3,452	0.00000000000000	4,209	0.00000001022020	3,442	0.00000000000000
3,927	0.00000000000000	3,451	0.00000000000000	4,208	0.00000000930913	3,440	0.00000000000000
3,927	0.00000000000000	3,451	0.00000000000000	4,206	0.00000000997938	3,439	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,926	0.00000000000000	3,449	0.00000000000000	4,206	0.00000000937714	3,438	0.00000000000000
3,923	0.00000000000000	3,449	0.00000000000000	4,204	0.00000000998752	3,438	0.00000000000000
3,922	0.00000000000000	3,448	0.00000000000000	4,203	0.00000000981903	3,437	0.00000000000000
3,921	0.00000000000000	3,447	0.00000000000000	4,203	0.00000000974775	3,436	0.00000000000000
3,921	0.00000000000000	3,447	0.00000000000000	4,202	0.00000001158710	3,435	0.00000000000000
3,920	0.00000000000000	3,447	0.00000000000000	4,202	0.00000001006060	3,435	0.00000000000000
3,919	0.00000000000000	3,445	0.00000000000000	4,201	0.00000000894083	3,434	0.00000000000000
3,919	0.00000000000000	3,445	0.00000000000000	4,200	0.00000000959455	3,433	0.00000000000000
3,918	0.00000000000000	3,443	0.00000000000000	4,198	0.00000001080660	3,433	0.00000000000000
3,917	0.00000000000000	3,443	0.00000000000000	4,198	0.0000001097180	3,433	0.00000000000000
3,916	0.00000000000000	3,443	0.00000000000000	4,186	0.00000000893348	3,432	0.00000000000000
3,916	0.00000000000000	3,443	0.00000000000000	4,184	0.00000000844941	3,432	0.00000000000000
3,915	0.00000000000000	3,443	0.00000000000000	4,183	0.00000000892989	3,432	0.00000000000000
3,915	0.00000000000000	3,441	0.00000000000000	4,182	0.00000000775213	3,431	0.00000000000000
3,914	0.00000000000000	3,440	0.00000000000000	4,182	0.00000000960806	3,431	0.00000000000000
3,914	0.00000000000000	3,439	0.00000000000000	4,181	0.00000000872997	3,431	0.00000000000000
3,914	0.00000000000000	3,438	0.00000000000000	4,180	0.0000000799188	3,429	0.00000000000000
3,913	0.00000000000000	3,438	0.00000000000000	4,179	0.00000000858666	3,428	0.00000000000000
3,913	0.00000000000000	3,438	0.00000000000000	4,179	0.00000000744084	3,427	0.00000000000000
3,913	0.00000000000000	3,437	0.00000000000000	4,178	0.00000000805117	3,426	0.00000000000000
3,913	0.00000000000000	3,437	0.00000000000000	4,177	0.00000000819420	3,425	0.00000000000000
3,911	0.00000000000000	3,436	0.00000000000000	4,176	0.00000000792478	3,424	0.00000000000000
3,911	0.00000000000000	3,436	0.00000000000000	4,173	0.00000000818064	3,424	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**
3,911	0.00000000000000	3,436	0.00000000000000	4,173	0.00000000786859	3,424	0.00000000000000
3,911	0.00000000000000	3,436	0.00000000000000	4,173	0.00000000721155	3,422	0.00000000000000
3,910	0.00000000000000	3,435	0.00000000000000	4,171	0.00000000774556	3,422	0.00000000000000
3,910	0.00000000000000	3,434	0.00000000000000	4,171	0.00000000761388	3,422	0.00000000000000
3,908	0.00000000000000	3,433	0.00000000000000	4,170	0.00000000761388	3,421	0.00000000000000
3,907	0.00000000000000	3,433	0.00000000000000	4,170	0.00000000720845	3,419	0.00000000000000
3,907	0.00000000000000	3,432	0.00000000000000	4,170	0.00000000921917	3,419	0.00000000000000
3,907	0.00000000000000	3,432	0.00000000000000	4,169	0.00000000873176	3,417	0.00000000000000
3,906	0.00000000000000	3,432	0.00000000000000	4,168	0.00000000749169	3,416	0.00000000000000
3,906	0.00000000000000	3,431	0.00000000000000	4,167	0.00000000738306	3,415	0.00000000000000
3,905	0.00000000000000	3,431	0.00000000000000	4,162	0.00000000639779	3,415	0.00000000000000
3,903	0.00000000000000	3,430	0.00000000000000	4,162	0.00000000732254	3,415	0.00000000000000
3,902	0.00000000000000	3,430	0.00000000000000	4,161	0.00000000697188	3,414	0.00000000000000
3,901	0.00000000000000	3,430	0.00000000000000	4,160	0.00000000691761	3,413	0.00000000000000
3,901	0.00000000000000	3,429	0.00000000000000	4,160	0.00000000761388	3,413	0.00000000000000
3,901	0.00000000000000	3,428	0.00000000000000	4,159	0.00000000709034	3,413	0.00000000000000
3,898	0.00000000000000	3,428	0.00000000000000	4,159	0.00000000755256	3,413	0.00000000000000
3,897	0.00000000000000	3,427	0.00000000000000	4,159	0.00000000825148	3,413	0.00000000000000
3,895	0.00000000000000	3,427	0.00000000000000	4,157	0.00000000675115	3,412	0.00000000000000
3,893	0.00000000000000	3,427	0.00000000000000	4,154	0.00000000619653	3,410	0.00000000000000
3,892	0.00000000000000	3,423	0.00000000000000	4,154	0.00000000702852	3,410	0.00000000000000
3,890	0.00000000000000	3,422	0.00000000000000	4,154	0.00000000702852	3,409	0.00000000000000
3,890	0.00000000000000	3,421	0.00000000000000	4,153	0.00000000659089	3,408	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,890	0.00000000000000	3,420	0.00000000000000	4,152	0.00000000774396	3,406	0.00000000000000
3,890	0.00000000000000	3,420	0.00000000000000	4,150	0.00000000649418	3,406	0.00000000000000
3,889	0.00000000000000	3,420	0.00000000000000	4,148	0.00000000638593	3,405	0.00000000000000
3,889	0.00000000000000	3,419	0.00000000000000	4,148	0.00000000691622	3,404	0.00000000000000
3,889	0.00000000000000	3,419	0.00000000000000	4,147	0.00000000594398	3,404	0.00000000000000
3,889	0.00000000000000	3,419	0.00000000000000	4,145	0.00000000562874	3,403	0.00000000000000
3,887	0.00000000000000	3,419	0.00000000000000	4,144	0.00000000589630	3,402	0.00000000000000
3,887	0.00000000000000	3,418	0.00000000000000	4,144	0.00000000720692	3,402	0.00000000000000
3,886	0.00000000000000	3,417	0.00000000000000	4,142	0.00000000545221	3,401	0.00000000000000
3,885	0.00000000000000	3,417	0.00000000000000	4,141	0.00000000609291	3,400	0.00000000000000
3,884	0.00000000000000	3,417	0.00000000000000	4,139	0.00000000584962	3,400	0.00000000000000
3,884	0.00000000000000	3,416	0.00000000000000	4,138	0.00000000665547	3,399	0.00000000000000
3,883	0.00000000000000	3,416	0.00000000000000	4,138	0.00000000618370	3,399	0.00000000000000
3,882	0.00000000000000	3,416	0.00000000000000	4,138	0.00000000613466	3,397	0.00000000000000
3,881	0.00000000000000	3,415	0.00000000000000	4,137	0.00000000561950	3,396	0.00000000000000
3,880	0.00000000000000	3,415	0.00000000000000	4,132	0.00000000503065	3,395	0.00000000000000
3,880	0.00000000000000	3,413	0.00000000000000	4,132	0.00000000589513	3,395	0.00000000000000
3,879	0.00000000000000	3,413	0.00000000000000	4,131	0.00000000674976	3,395	0.00000000000000
3,879	0.00000000000000	3,413	0.00000000000000	4,129	0.00000000527294	3,394	0.00000000000000
3,879	0.00000000000000	3,412	0.00000000000000	4,124	0.00000000491143	3,394	0.00000000000000
3,878	0.00000000000000	3,411	0.00000000000000	4,124	0.00000000548541	3,393	0.00000000000000
3,878	0.00000000000000	3,409	0.00000000000000	4,121	0.00000000519429	3,392	0.00000000000000
3,878	0.00000000000000	3,409	0.00000000000000	4,120	0.00000000535681	3,391	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,877	0.00000000000000	3,409	0.00000000000000	4,120	0.00000000576730	3,390	0.00000000000000
3,876	0.00000000000000	3,406	0.00000000000000	4,118	0.00000000456519	3,390	0.00000000000000
3,876	0.00000000000000	3,406	0.00000000000000	4,117	0.00000000599026	3,389	0.00000000000000
3,876	0.00000000000000	3,406	0.00000000000000	4,114	0.00000000562756	3,388	0.00000000000000
3,876	0.00000000000000	3,405	0.00000000000000	4,113	0.00000000449562	3,388	0.00000000000000
3,874	0.00000000000000	3,403	0.00000000000000	4,113	0.00000000475092	3,387	0.00000000000000
3,873	0.00000000000000	3,402	0.00000000000000	4,113	0.00000000584846	3,387	0.00000000000000
3,873	0.00000000000000	3,402	0.00000000000000	4,112	0.00000000467509	3,383	0.00000000000000
3,872	0.00000000000000	3,401	0.00000000000000	4,108	0.00000000486502	3,383	0.00000000000000
3,872	0.00000000000000	3,401	0.00000000000000	4,107	0.00000000441649	3,383	0.00000000000000
3,869	0.00000000000000	3,401	0.00000000000000	4,106	0.00000000414264	3,380	0.00000000000000
3,869	0.00000000000000	3,401	0.00000000000000	4,104	0.00000000453195	3,380	0.00000000000000
3,868	0.00000000000000	3,401	0.00000000000000	4,103	0.00000000435395	3,380	0.00000000000000
3,867	0.00000000000000	3,399	0.00000000000000	4,102	0.00000000407944	3,380	0.00000000000000
3,867	0.00000000000000	3,399	0.00000000000000	4,100	0.00000000431104	3,379	0.00000000000000
3,867	0.00000000000000	3,398	0.00000000000000	4,100	0.00000000388462	3,378	0.00000000000000
3,866	0.00000000000000	3,397	0.00000000000000	4,099	0.00000000452341	3,378	0.00000000000000
3,866	0.00000000000000	3,397	0.00000000000000	4,096	0.00000000391894	3,377	0.00000000000000
3,865	0.00000000000000	3,396	0.00000000000000	4,096	0.00000000417145	3,377	0.00000000000000
3,864	0.00000000000000	3,396	0.00000000000000	4,095	0.00000000387970	3,376	0.00000000000000
3,864	0.00000000000000	3,396	0.00000000000000	4,094	0.00000000381799	3,375	0.00000000000000
3,864	0.00000000000000	3,395	0.00000000000000	4,091	0.00000000384597	3,373	0.00000000000000
3,864	0.00000000000000	3,395	0.00000000000000	4,090	0.00000000398059	3,372	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,863	0.00000000000000	3,394	0.00000000000000	4,089	0.00000000431104	3,372	0.00000000000000
3,860	0.00000000000000	3,394	0.00000000000000	4,087	0.00000000387726	3,372	0.00000000000000
3,860	0.00000000000000	3,393	0.00000000000000	4,085	0.00000000403873	3,371	0.00000000000000
3,860	0.00000000000000	3,393	0.00000000000000	4,084	0.00000000397561	3,371	0.00000000000000
3,859	0.00000000000000	3,392	0.00000000000000	4,083	0.00000000536450	3,370	0.00000000000000
3,859	0.00000000000000	3,391	0.00000000000000	4,083	0.00000000397482	3,370	0.00000000000000
3,858	0.00000000000000	3,391	0.00000000000000	4,081	0.00000000381555	3,369	0.00000000000000
3,858	0.00000000000000	3,390	0.00000000000000	4,078	0.00000000357476	3,369	0.00000000000000
3,857	0.00000000000000	3,390	0.00000000000000	4,075	0.00000000363578	3,368	0.00000000000000
3,857	0.00000000000000	3,389	0.00000000000000	4,074	0.00000000363501	3,368	0.00000000000000
3,856	0.00000000000000	3,388	0.00000000000000	4,074	0.00000000369159	3,366	0.00000000000000
3,856	0.00000000000000	3,387	0.00000000000000	4,073	0.00000000327320	3,365	0.00000000000000
3,856	0.00000000000000	3,387	0.00000000000000	4,071	0.00000000360441	3,365	0.00000000000000
3,856	0.00000000000000	3,387	0.00000000000000	4,070	0.00000000313828	3,365	0.00000000000000
3,856	0.00000000000000	3,385	0.00000000000000	4,069	0.00000000334668	3,365	0.00000000000000
3,855	0.00000000000000	3,384	0.00000000000000	4,069	0.00000000407163	3,364	0.00000000000000
3,854	0.00000000000000	3,383	0.00000000000000	4,069	0.00000000332037	3,364	0.00000000000000
3,852	0.00000000000000	3,381	0.00000000000000	4,068	0.00000000332037	3,362	0.00000000000000
3,852	0.00000000000000	3,381	0.00000000000000	4,067	0.00000000335019	3,360	0.00000000000000
3,851	0.00000000000000	3,380	0.00000000000000	4,067	0.00000000329382	3,359	0.00000000000000
3,850	0.00000000000000	3,379	0.00000000000000	4,067	0.00000000332380	3,359	0.00000000000000
3,849	0.00000000000000	3,379	0.00000000000000	4,066	0.00000000375914	3,359	0.00000000000000
3,848	0.00000000000000	3,378	0.00000000000000	4,066	0.00000000326771	3,359	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,848	0.00000000000000	3,378	0.00000000000000	4,065	0.00000000335166	3,358	0.00000000000000
3,847	0.00000000000000	3,378	0.00000000000000	4,063	0.00000000310895	3,357	0.00000000000000
3,846	0.00000000000000	3,378	0.00000000000000	4,062	0.00000000316142	3,357	0.00000000000000
3,842	0.00000000000000	3,377	0.00000000000000	4,060	0.00000000316473	3,356	0.00000000000000
3,842	0.00000000000000	3,377	0.00000000000000	4,057	0.00000000321469	3,356	0.00000000000000
3,841	0.00000000000000	3,377	0.00000000000000	4,057	0.00000000293704	3,356	0.00000000000000
3,841	0.00000000000000	3,375	0.00000000000000	4,055	0.00000000277554	3,355	0.00000000000000
3,840	0.00000000000000	3,375	0.00000000000000	4,055	0.00000000301234	3,353	0.00000000000000
3,840	0.00000000000000	3,375	0.00000000000000	4,054	0.00000000299097	3,353	0.00000000000000
3,839	0.00000000000000	3,374	0.00000000000000	4,054	0.00000000321469	3,352	0.00000000000000
3,838	0.00000000000000	3,373	0.00000000000000	4,047	0.00000000282048	3,352	0.00000000000000
3,836	0.00000000000000	3,372	0.00000000000000	4,047	0.00000000284379	3,352	0.00000000000000
3,835	0.00000000000000	3,372	0.00000000000000	4,045	0.00000000272883	3,352	0.00000000000000
3,834	0.00000000000000	3,370	0.00000000000000	4,044	0.00000000272473	3,351	0.00000000000000
3,834	0.00000000000000	3,370	0.00000000000000	4,043	0.00000000270684	3,351	0.00000000000000
3,834	0.00000000000000	3,368	0.00000000000000	4,042	0.00000000253345	3,351	0.00000000000000
3,833	0.00000000000000	3,368	0.00000000000000	4,041	0.00000000259575	3,349	0.00000000000000
3,833	0.00000000000000	3,367	0.00000000000000	4,041	0.00000000324203	3,348	0.00000000000000
3,833	0.00000000000000	3,365	0.00000000000000	4,041	0.00000000281689	3,348	0.00000000000000
3,832	0.00000000000000	3,364	0.00000000000000	4,040	0.00000000265983	3,346	0.00000000000000
3,831	0.00000000000000	3,364	0.00000000000000	4,040	0.00000000263741	3,345	0.00000000000000
3,831	0.00000000000000	3,364	0.00000000000000	4,039	0.00000000264016	3,345	0.00000000000000
3,829	0.00000000000000	3,363	0.00000000000000	4,037	0.00000000375594	3,345	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,828	0.00000000000000	3,362	0.00000000000000	4,034	0.00000000231174	3,344	0.00000000000000
3,828	0.00000000000000	3,360	0.00000000000000	4,034	0.00000000265983	3,344	0.00000000000000
3,828	0.00000000000000	3,358	0.00000000000000	4,034	0.00000000248740	3,343	0.00000000000000
3,828	0.00000000000000	3,358	0.00000000000000	4,033	0.00000000248740	3,343	0.00000000000000
3,828	0.00000000000000	3,357	0.00000000000000	4,033	0.00000000265983	3,343	0.00000000000000
3,828	0.00000000000000	3,356	0.00000000000000	4,030	0.00000000236805	3,342	0.00000000000000
3,828	0.00000000000000	3,354	0.00000000000000	4,030	0.00000000242624	3,341	0.00000000000000
3,825	0.00000000000000	3,354	0.00000000000000	4,030	0.00000000298455	3,341	0.00000000000000
3,824	0.00000000000000	3,354	0.00000000000000	4,030	0.00000000248898	3,341	0.00000000000000
3,819	0.00000000000000	3,354	0.00000000000000	4,029	0.00000000252967	3,341	0.00000000000000
3,819	0.00000000000000	3,354	0.00000000000000	4,028	0.00000000234896	3,341	0.00000000000000
3,819	0.00000000000000	3,353	0.00000000000000	4,025	0.00000000270684	3,341	0.00000000000000
3,818	0.00000000000000	3,353	0.00000000000000	4,023	0.00000000221380	3,341	0.00000000000000
3,816	0.00000000000000	3,353	0.00000000000000	4,020	0.00000000321936	3,340	0.00000000000000
3,815	0.00000000000000	3,353	0.00000000000000	4,020	0.00000000236805	3,338	0.00000000000000
3,814	0.00000000000000	3,351	0.00000000000000	4,019	0.00000000242624	3,337	0.00000000000000
3,814	0.00000000000000	3,350	0.00000000000000	4,019	0.00000000219603	3,336	0.00000000000000
3,814	0.00000000000000	3,349	0.00000000000000	4,017	0.00000000204036	3,336	0.00000000000000
3,813	0.00000000000000	3,349	0.00000000000000	4,015	0.00000000226987	3,335	0.00000000000000
3,811	0.00000000000000	3,348	0.00000000000000	4,014	0.00000000214528	3,335	0.00000000000000
3,811	0.00000000000000	3,348	0.00000000000000	4,012	0.00000000219558	3,335	0.00000000000000
3,810	0.00000000000000	3,347	0.00000000000000	4,012	0.00000000239173	3,335	0.00000000000000
3,809	0.00000000000000	3,347	0.00000000000000	4,009	0.00000000202103	3,335	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,808	0.00000000000000	3,345	0.00000000000000	4,009	0.00000000197097	3,334	0.00000000000000
3,808	0.00000000000000	3,345	0.00000000000000	4,008	0.00000000214256	3,332	0.00000000000000
3,807	0.00000000000000	3,344	0.00000000000000	4,008	0.00000000202017	3,331	0.00000000000000
3,806	0.00000000000000	3,341	0.00000000000000	4,007	0.00000000209106	3,331	0.00000000000000
3,806	0.00000000000000	3,341	0.00000000000000	4,004	0.00000000177375	3,331	0.00000000000000
3,806	0.00000000000000	3,339	0.00000000000000	4,002	0.00000000192353	3,331	0.00000000000000
3,804	0.00000000000000	3,338	0.00000000000000	4,001	0.00000000194144	3,330	0.00000000000000
3,804	0.00000000000000	3,338	0.00000000000000	4,000	0.00000000192553	3,329	0.00000000000000
3,803	0.00000000000000	3,338	0.00000000000000	3,999	0.00000000176020	3,329	0.00000000000000
3,801	0.00000000000000	3,338	0.00000000000000	3,998	0.00000000194021	3,328	0.00000000000000
3,800	0.00000000000000	3,338	0.00000000000000	3,996	0.00000000182960	3,328	0.00000000000000
3,800	0.00000000000000	3,338	0.00000000000000	3,994	0.00000000221380	3,328	0.00000000000000
3,799	0.00000000000000	3,337	0.00000000000000	3,991	0.00000000180116	3,327	0.00000000000000
3,798	0.00000000000000	3,337	0.00000000000000	3,991	0.00000000162632	3,326	0.00000000000000
3,797	0.00000000000000	3,336	0.00000000000000	3,990	0.00000000186055	3,325	0.00000000000000
3,797	0.00000000000000	3,336	0.00000000000000	3,990	0.00000000175824	3,324	0.00000000000000
3,796	0.00000000000000	3,336	0.00000000000000	3,990	0.00000000173105	3,323	0.00000000000000
3,796	0.00000000000000	3,335	0.00000000000000	3,989	0.00000000169550	3,323	0.00000000000000
3,795	0.00000000000000	3,335	0.00000000000000	3,987	0.00000000169206	3,323	0.00000000000000
3,795	0.00000000000000	3,335	0.00000000000000	3,987	0.00000000178525	3,322	0.00000000000000
3,795	0.00000000000000	3,333	0.00000000000000	3,986	0.00000000148815	3,321	0.00000000000000
3,794	0.00000000000000	3,333	0.00000000000000	3,986	0.00000000184474	3,321	0.00000000000000
3,794	0.00000000000000	3,332	0.00000000000000	3,984	0.00000000181446	3,321	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,792	0.00000000000000	3,332	0.00000000000000	3,981	0.00000000155992	3,320	0.00000000000000
3,792	0.00000000000000	3,331	0.00000000000000	3,979	0.00000000158392	3,320	0.00000000000000
3,790	0.00000000000000	3,330	0.00000000000000	3,978	0.00000000155864	3,319	0.00000000000000
3,790	0.00000000000000	3,329	0.00000000000000	3,976	0.00000000181680	3,319	0.00000000000000
3,788	0.00000000000000	3,329	0.00000000000000	3,974	0.00000000225308	3,318	0.00000000000000
3,787	0.00000000000000	3,329	0.00000000000000	3,973	0.00000000159706	3,317	0.00000000000000
3,786	0.00000000000000	3,329	0.00000000000000	3,970	0.00000000147438	3,317	0.00000000000000
3,785	0.00000000000000	3,329	0.00000000000000	3,970	0.00000000155864	3,317	0.00000000000000
3,785	0.00000000000000	3,326	0.00000000000000	3,965	0.00000000147222	3,316	0.00000000000000
3,783	0.00000000000000	3,325	0.00000000000000	3,965	0.00000000138255	3,316	0.00000000000000
3,783	0.00000000000000	3,323	0.00000000000000	3,964	0.00000000143633	3,315	0.00000000000000
3,783	0.00000000000000	3,322	0.00000000000000	3,961	0.00000000123530	3,315	0.00000000000000
3,782	0.00000000000000	3,322	0.00000000000000	3,961	0.00000000165091	3,314	0.00000000000000
3,782	0.00000000000000	3,321	0.00000000000000	3,961	0.00000000128558	3,314	0.00000000000000
3,782	0.00000000000000	3,320	0.00000000000000	3,958	0.00000000127432	3,312	0.00000000000000
3,782	0.00000000000000	3,319	0.00000000000000	3,957	0.00000000132642	3,312	0.00000000000000
3,781	0.00000000000000	3,319	0.00000000000000	3,956	0.00000000160994	3,311	0.00000000000000
3,780	0.00000000000000	3,319	0.00000000000000	3,956	0.00000000132576	3,310	0.00000000000000
3,780	0.00000000000000	3,319	0.00000000000000	3,954	0.00000000131436	3,310	0.00000000000000
3,779	0.00000000000000	3,319	0.00000000000000	3,954	0.00000000131436	3,308	0.00000000000000
3,779	0.00000000000000	3,318	0.00000000000000	3,953	0.00000000136371	3,308	0.00000000000000
3,778	0.00000000000000	3,317	0.00000000000000	3,952	0.00000000128681	3,308	0.00000000000000
3,778	0.00000000000000	3,317	0.00000000000000	3,952	0.00000000119124	3,306	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,777	0.00000000000000	3,316	0.00000000000000	3,950	0.00000000107726	3,306	0.00000000000000
3,775	0.00000000000000	3,314	0.00000000000000	3,947	0.00000000111434	3,305	0.00000000000000
3,775	0.00000000000000	3,314	0.00000000000000	3,947	0.00000000181561	3,304	0.00000000000000
3,775	0.00000000000000	3,313	0.00000000000000	3,945	0.00000000108449	3,302	0.00000000000000
3,773	0.00000000000000	3,310	0.00000000000000	3,944	0.00000000116622	3,302	0.00000000000000
3,773	0.00000000000000	3,309	0.00000000000000	3,944	0.00000000102617	3,300	0.00000000000000
3,773	0.00000000000000	3,308	0.00000000000000	3,943	0.00000000105806	3,300	0.00000000000000
3,772	0.00000000000000	3,308	0.00000000000000	3,943	0.00000000092913	3,299	0.00000000000000
3,771	0.00000000000000	3,307	0.00000000000000	3,940	0.00000000126679	3,297	0.00000000000000
3,770	0.00000000000000	3,307	0.00000000000000	3,940	0.00000000089335	3,296	0.00000000000000
3,769	0.00000000000000	3,307	0.00000000000000	3,939	0.00000000109602	3,295	0.00000000000000
3,767	0.00000000000000	3,306	0.00000000000000	3,939	0.00000000113156	3,295	0.00000000000000
3,766	0.00000000000000	3,305	0.00000000000000	3,938	0.00000000096647	3,293	0.00000000000000
3,766	0.00000000000000	3,305	0.00000000000000	3,935	0.00000000099160	3,293	0.00000000000000
3,765	0.00000000000000	3,304	0.00000000000000	3,935	0.00000000107613	3,291	0.00000000000000
3,765	0.00000000000000	3,302	0.00000000000000	3,934	0.00000000121097	3,291	0.00000000000000
3,763	0.00000000000000	3,302	0.00000000000000	3,934	0.00000000087583	3,290	0.00000000000000
3,763	0.00000000000000	3,302	0.00000000000000	3,934	0.00000000102639	3,290	0.00000000000000
3,761	0.00000000000000	3,301	0.00000000000000	3,934	0.00000000078571	3,290	0.00000000000000
3,760	0.00000000000000	3,301	0.00000000000000	3,931	0.00000000087583	3,289	0.00000000000000
3,760	0.00000000000000	3,301	0.00000000000000	3,930	0.00000000087583	3,289	0.00000000000000
3,758	0.00000000000000	3,300	0.00000000000000	3,927	0.00000000080961	3,289	0.00000000000000
3,757	0.00000000000000	3,300	0.00000000000000	3,925	0.00000000076828	3,289	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,757	0.00000000000000	3,299	0.00000000000000	3,921	0.00000000061285	3,288	0.00000000000000
3,756	0.00000000000000	3,298	0.00000000000000	3,919	0.00000000107562	3,287	0.00000000000000
3,756	0.00000000000000	3,297	0.00000000000000	3,917	0.00000000061457	3,287	0.00000000000000
3,755	0.00000000000000	3,296	0.00000000000000	3,916	0.00000000090564	3,287	0.00000000000000
3,755	0.00000000000000	3,296	0.00000000000000	3,916	0.00000000076210	3,285	0.00000000000000
3,752	0.00000000000000	3,296	0.00000000000000	3,914	0.00000000057734	3,282	0.00000000000000
3,752	0.00000000000000	3,295	0.00000000000000	3,914	0.00000000063357	3,281	0.00000000000000
3,752	0.00000000000000	3,294	0.00000000000000	3,912	0.00000000072726	3,280	0.00000000000000
3,751	0.00000000000000	3,294	0.00000000000000	3,908	0.00000000046387	3,278	0.00000000000000
3,750	0.00000000000000	3,292	0.00000000000000	3,906	0.00000000055584	3,278	0.00000000000000
3,750	0.00000000000000	3,292	0.00000000000000	3,905	0.00000000060947	3,278	0.00000000000000
3,750	0.00000000000000	3,292	0.00000000000000	3,903	0.00000000119228	3,277	0.00000000000000
3,749	0.00000000000000	3,292	0.00000000000000	3,903	0.00000000058672	3,276	0.00000000000000
3,749	0.00000000000000	3,292	0.00000000000000	3,899	0.00000000055584	3,275	0.00000000000000
3,747	0.00000000000000	3,291	0.00000000000000	3,898	0.00000000074497	3,275	0.00000000000000
3,747	0.00000000000000	3,290	0.00000000000000	3,898	0.00000000054583	3,273	0.00000000000000
3,746	0.00000000000000	3,289	0.00000000000000	3,898	0.00000000054583	3,273	0.00000000000000
3,746	0.00000000000000	3,289	0.00000000000000	3,895	0.00000000042719	3,273	0.00000000000000
3,745	0.00000000000000	3,288	0.00000000000000	3,894	0.00000000035667	3,272	0.00000000000000
3,745	0.00000000000000	3,287	0.00000000000000	3,892	0.00000000038056	3,272	0.00000000000000
3,744	0.00000000000000	3,287	0.00000000000000	3,891	0.00000000049223	3,271	0.00000000000000
3,744	0.00000000000000	3,284	0.00000000000000	3,890	0.00000000042837	3,270	0.00000000000000
3,742	0.00000000000000	3,284	0.00000000000000	3,888	0.00000000033871	3,270	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,741	0.00000000000000	3,281	0.00000000000000	3,888	0.00000000037394	3,269	0.00000000000000
3,741	0.00000000000000	3,281	0.00000000000000	3,888	0.00000000042719	3,269	0.00000000000000
3,741	0.00000000000000	3,281	0.00000000000000	3,886	0.00000000039939	3,269	0.00000000000000
3,738	0.00000000000000	3,281	0.00000000000000	3,886	0.00000000038217	3,267	0.00000000000000
3,738	0.00000000000000	3,280	0.00000000000000	3,885	0.00000000017661	3,267	0.00000000000000
3,737	0.00000000000000	3,279	0.00000000000000	3,884	0.00000000038056	3,267	0.00000000000000
3,737	0.00000000000000	3,279	0.00000000000000	3,883	0.00000000047023	3,266	0.00000000000000
3,737	0.00000000000000	3,279	0.00000000000000	3,878	0.00000000028338	3,266	0.00000000000000
3,736	0.00000000000000	3,279	0.00000000000000	3,876	0.00000000047424	3,265	0.00000000000000
3,735	0.00000000000000	3,279	0.00000000000000	3,876	0.00000000000000	3,265	0.00000000000000
3,734	0.00000000000000	3,276	0.00000000000000	3,876	0.00000000027074	3,264	0.00000000000000
3,734	0.00000000000000	3,276	0.00000000000000	3,873	0.00000000023698	3,264	0.00000000000000
3,734	0.00000000000000	3,275	0.00000000000000	3,873	0.00000000014118	3,263	0.00000000000000
3,733	0.00000000000000	3,273	0.00000000000000	3,873	0.00000000018121	3,262	0.00000000000000
3,733	0.00000000000000	3,273	0.00000000000000	3,871	0.00000000043592	3,262	0.00000000000000
3,732	0.00000000000000	3,272	0.00000000000000	3,871	0.00000000034114	3,261	0.00000000000000
3,732	0.00000000000000	3,271	0.00000000000000	3,870	0.00000000018202	3,260	0.00000000000000
3,731	0.00000000000000	3,270	0.00000000000000	3,870	0.00000000000000	3,260	0.00000000000000
3,731	0.00000000000000	3,270	0.00000000000000	3,870	0.00000000000000	3,259	0.00000000000000
3,731	0.00000000000000	3,270	0.00000000000000	3,869	0.00000000063619	3,259	0.00000000000000
3,731	0.00000000000000	3,268	0.00000000000000	3,868	0.00000000020436	3,258	0.00000000000000
3,730	0.00000000000000	3,268	0.00000000000000	3,868	0.00000000000000	3,258	0.00000000000000
3,730	0.00000000000000	3,268	0.00000000000000	3,867	0.00000000000000	3,257	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,729	0.00000000000000	3,265	0.00000000000000	3,866	0.00000000000000	3,257	0.00000000000000
3,729	0.00000000000000	3,263	0.00000000000000	3,865	0.00000000059610	3,256	0.00000000000000
3,729	0.00000000000000	3,262	0.00000000000000	3,864	0.00000000000000	3,256	0.00000000000000
3,729	0.00000000000000	3,260	0.00000000000000	3,863	0.00000000000000	3,256	0.00000000000000
3,728	0.00000000000000	3,259	0.00000000000000	3,861	0.00000000000000	3,255	0.00000000000000
3,727	0.00000000000000	3,258	0.00000000000000	3,859	0.00000000027589	3,254	0.00000000000000
3,726	0.00000000000000	3,258	0.00000000000000	3,856	0.00000000000000	3,253	0.00000000000000
3,725	0.00000000000000	3,257	0.00000000000000	3,855	0.00000000000000	3,252	0.00000000000000
3,725	0.00000000000000	3,256	0.00000000000000	3,853	0.00000000000000	3,250	0.00000000000000
3,722	0.00000000000000	3,256	0.00000000000000	3,851	0.00000000000000	3,249	0.00000000000000
3,722	0.00000000000000	3,256	0.00000000000000	3,850	0.00000000040982	3,248	0.00000000000000
3,721	0.00000000000000	3,255	0.00000000000000	3,849	0.00000000000000	3,248	0.00000000000000
3,721	0.00000000000000	3,255	0.00000000000000	3,849	0.00000000018121	3,247	0.00000000000000
3,719	0.00000000000000	3,254	0.00000000000000	3,846	0.00000000000000	3,246	0.00000000000000
3,718	0.00000000000000	3,254	0.00000000000000	3,845	0.00000000000000	3,246	0.00000000000000
3,716	0.00000000000000	3,254	0.00000000000000	3,844	0.00000000000000	3,246	0.00000000000000
3,716	0.00000000000000	3,253	0.00000000000000	3,840	0.00000000000000	3,245	0.00000000000000
3,715	0.00000000000000	3,253	0.00000000000000	3,838	0.00000000000000	3,245	0.00000000000000
3,715	0.00000000000000	3,250	0.00000000000000	3,837	0.00000000000000	3,244	0.00000000000000
3,715	0.00000000000000	3,249	0.00000000000000	3,836	0.00000000000000	3,244	0.00000000000000
3,714	0.00000000000000	3,249	0.00000000000000	3,836	0.00000000000000	3,243	0.00000000000000
3,714	0.00000000000000	3,249	0.00000000000000	3,834	0.00000000000000	3,243	0.00000000000000
3,714	0.00000000000000	3,246	0.00000000000000	3,833	0.00000000000000	3,242	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,713	0.00000000000000	3,246	0.00000000000000	3,832	0.00000000000000	3,242	0.00000000000000
3,713	0.00000000000000	3,246	0.00000000000000	3,830	0.00000000000000	3,241	0.00000000000000
3,711	0.00000000000000	3,246	0.00000000000000	3,828	0.00000000000000	3,240	0.00000000000000
3,710	0.00000000000000	3,244	0.00000000000000	3,826	0.00000000000000	3,239	0.00000000000000
3,708	0.00000000000000	3,244	0.00000000000000	3,822	0.00000000000000	3,239	0.00000000000000
3,707	0.00000000000000	3,242	0.00000000000000	3,818	0.00000000000000	3,238	0.00000000000000
3,707	0.00000000000000	3,242	0.00000000000000	3,818	0.00000000000000	3,238	0.00000000000000
3,706	0.00000000000000	3,241	0.00000000000000	3,818	0.00000000000000	3,237	0.00000000000000
3,706	0.00000000000000	3,241	0.00000000000000	3,817	0.00000000000000	3,237	0.00000000000000
3,706	0.00000000000000	3,241	0.00000000000000	3,816	0.00000000000000	3,237	0.00000000000000
3,706	0.00000000000000	3,241	0.00000000000000	3,815	0.00000000000000	3,235	0.00000000000000
3,703	0.00000000000000	3,241	0.00000000000000	3,814	0.00000000000000	3,235	0.00000000000000
3,703	0.00000000000000	3,241	0.00000000000000	3,814	0.00000000000000	3,235	0.00000000000000
3,703	0.00000000000000	3,240	0.00000000000000	3,814	0.00000000000000	3,232	0.00000000000000
3,703	0.00000000000000	3,240	0.00000000000000	3,811	0.00000000000000	3,230	0.00000000000000
3,701	0.00000000000000	3,240	0.00000000000000	3,811	0.00000000000000	3,229	0.00000000000000
3,701	0.00000000000000	3,239	0.00000000000000	3,808	0.00000000000000	3,227	0.00000000000000
3,699	0.00000000000000	3,238	0.00000000000000	3,806	0.00000000000000	3,227	0.00000000000000
3,699	0.00000000000000	3,236	0.00000000000000	3,804	0.00000000000000	3,226	0.00000000000000
3,699	0.00000000000000	3,236	0.00000000000000	3,802	0.00000000000000	3,226	0.00000000000000
3,699	0.00000000000000	3,235	0.00000000000000	3,800	0.00000000000000	3,225	0.00000000000000
3,699	0.00000000000000	3,235	0.00000000000000	3,799	0.00000000000000	3,225	0.00000000000000
3,697	0.00000000000000	3,235	0.00000000000000	3,798	0.00000000000000	3,224	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,696	0.00000000000000	3,235	0.00000000000000	3,797	0.00000000000000	3,222	0.00000000000000
3,696	0.00000000000000	3,234	0.00000000000000	3,796	0.00000000000000	3,222	0.00000000000000
3,695	0.00000000000000	3,233	0.00000000000000	3,795	0.00000000000000	3,220	0.00000000000000
3,694	0.00000000000000	3,232	0.00000000000000	3,795	0.00000000000000	3,220	0.00000000000000
3,694	0.00000000000000	3,231	0.00000000000000	3,795	0.00000000000000	3,220	0.00000000000000
3,694	0.00000000000000	3,230	0.00000000000000	3,794	0.00000000000000	3,220	0.00000000000000
3,693	0.00000000000000	3,227	0.00000000000000	3,794	0.00000000000000	3,220	0.00000000000000
3,690	0.00000000000000	3,226	0.00000000000000	3,794	0.00000000000000	3,219	0.00000000000000
3,689	0.00000000000000	3,226	0.00000000000000	3,793	0.00000000000000	3,218	0.00000000000000
3,688	0.00000000000000	3,226	0.00000000000000	3,792	0.00000000000000	3,215	0.00000000000000
3,688	0.00000000000000	3,225	0.00000000000000	3,791	0.00000000000000	3,214	0.00000000000000
3,687	0.00000000000000	3,224	0.00000000000000	3,791	0.00000000000000	3,214	0.00000000000000
3,686	0.00000000000000	3,220	0.00000000000000	3,790	0.00000000000000	3,214	0.00000000000000
3,686	0.00000000000000	3,220	0.00000000000000	3,790	0.00000000000000	3,214	0.00000000000000
3,686	0.00000000000000	3,219	0.00000000000000	3,789	0.00000000000000	3,213	0.00000000000000
3,686	0.00000000000000	3,218	0.00000000000000	3,787	0.00000000000000	3,213	0.00000000000000
3,679	0.00000000000000	3,217	0.00000000000000	3,786	0.00000000000000	3,212	0.00000000000000
3,679	0.00000000000000	3,217	0.00000000000000	3,786	0.00000000000000	3,212	0.00000000000000
3,677	0.00000000000000	3,216	0.00000000000000	3,784	0.00000000000000	3,212	0.00000000000000
3,675	0.00000000000000	3,216	0.00000000000000	3,784	0.00000000000000	3,211	0.00000000000000
3,675	0.00000000000000	3,212	0.00000000000000	3,782	0.00000000000000	3,211	0.00000000000000
3,675	0.00000000000000	3,212	0.00000000000000	3,781	0.00000000000000	3,211	0.00000000000000
3,675	0.00000000000000	3,211	0.00000000000000	3,780	0.00000000000000	3,209	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,675	0.00000000000000	3,210	0.00000000000000	3,779	0.00000000000000	3,207	0.00000000000000
3,674	0.00000000000000	3,210	0.00000000000000	3,779	0.00000000000000	3,207	0.00000000000000
3,674	0.00000000000000	3,209	0.00000000000000	3,779	0.00000000000000	3,207	0.00000000000000
3,673	0.00000000000000	3,209	0.00000000000000	3,778	0.00000000000000	3,207	0.00000000000000
3,673	0.00000000000000	3,208	0.00000000000000	3,778	0.00000000000000	3,204	0.00000000000000
3,672	0.00000000000000	3,208	0.00000000000000	3,776	0.00000000000000	3,204	0.00000000000000
3,672	0.00000000000000	3,207	0.00000000000000	3,776	0.00000000000000	3,203	0.00000000000000
3,671	0.00000000000000	3,207	0.00000000000000	3,774	0.00000000000000	3,203	0.00000000000000
3,670	0.00000000000000	3,205	0.00000000000000	3,774	0.00000000000000	3,202	0.00000000000000
3,670	0.00000000000000	3,204	0.00000000000000	3,773	0.00000000000000	3,202	0.00000000000000
3,670	0.00000000000000	3,203	0.00000000000000	3,773	0.00000000000000	3,200	0.00000000000000
3,668	0.00000000000000	3,203	0.00000000000000	3,773	0.00000000000000	3,199	0.00000000000000
3,666	0.00000000000000	3,201	0.00000000000000	3,772	0.00000000000000	3,199	0.00000000000000
3,665	0.00000000000000	3,201	0.00000000000000	3,769	0.00000000000000	3,197	0.00000000000000
3,665	0.00000000000000	3,200	0.00000000000000	3,769	0.00000000000000	3,196	0.00000000000000
3,665	0.00000000000000	3,199	0.00000000000000	3,769	0.00000000000000	3,195	0.00000000000000
3,664	0.00000000000000	3,199	0.00000000000000	3,768	0.00000000000000	3,191	0.00000000000000
3,664	0.00000000000000	3,198	0.00000000000000	3,766	0.00000000000000	3,191	0.00000000000000
3,663	0.00000000000000	3,198	0.00000000000000	3,762	0.00000000000000	3,191	0.00000000000000
3,662	0.00000000000000	3,197	0.00000000000000	3,761	0.00000000000000	3,188	0.00000000000000
3,661	0.00000000000000	3,197	0.00000000000000	3,761	0.00000000000000	3,188	0.00000000000000
3,660	0.00000000000000	3,195	0.00000000000000	3,760	0.00000000000000	3,187	0.00000000000000
3,659	0.00000000000000	3,195	0.00000000000000	3,759	0.00000000000000	3,186	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,659	0.00000000000000	3,195	0.00000000000000	3,755	0.00000000000000	3,186	0.00000000000000
3,654	0.00000000000000	3,194	0.00000000000000	3,755	0.00000000000000	3,185	0.00000000000000
3,654	0.00000000000000	3,194	0.00000000000000	3,751	0.00000000000000	3,184	0.00000000000000
3,654	0.00000000000000	3,194	0.00000000000000	3,751	0.00000000000000	3,183	0.00000000000000
3,653	0.00000000000000	3,192	0.00000000000000	3,749	0.00000000000000	3,182	0.00000000000000
3,653	0.00000000000000	3,191	0.00000000000000	3,748	0.00000000000000	3,181	0.00000000000000
3,652	0.00000000000000	3,190	0.00000000000000	3,746	0.00000000000000	3,181	0.00000000000000
3,651	0.00000000000000	3,190	0.00000000000000	3,745	0.00000000000000	3,180	0.00000000000000
3,650	0.00000000000000	3,189	0.00000000000000	3,745	0.00000000000000	3,179	0.00000000000000
3,650	0.00000000000000	3,189	0.00000000000000	3,742	0.00000000000000	3,178	0.00000000000000
3,650	0.00000000000000	3,186	0.00000000000000	3,742	0.00000000000000	3,178	0.00000000000000
3,649	0.00000000000000	3,185	0.00000000000000	3,739	0.00000000000000	3,178	0.00000000000000
3,649	0.00000000000000	3,184	0.00000000000000	3,739	0.00000000000000	3,178	0.00000000000000
3,648	0.00000000000000	3,183	0.00000000000000	3,739	0.00000000000000	3,177	0.00000000000000
3,648	0.00000000000000	3,183	0.00000000000000	3,738	0.00000000000000	3,177	0.00000000000000
3,647	0.00000000000000	3,182	0.00000000000000	3,736	0.00000000000000	3,177	0.00000000000000
3,646	0.00000000000000	3,180	0.00000000000000	3,736	0.00000000000000	3,177	0.00000000000000
3,645	0.00000000000000	3,179	0.00000000000000	3,736	0.00000000000000	3,177	0.00000000000000
3,644	0.00000000000000	3,176	0.00000000000000	3,734	0.00000000000000	3,176	0.00000000000000
3,644	0.00000000000000	3,176	0.00000000000000	3,734	0.00000000000000	3,176	0.00000000000000
3,643	0.00000000000000	3,176	0.00000000000000	3,733	0.00000000000000	3,175	0.00000000000000
3,643	0.00000000000000	3,175	0.00000000000000	3,731	0.00000000000000	3,174	0.00000000000000
3,642	0.00000000000000	3,175	0.00000000000000	3,730	0.00000000000000	3,174	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,642	0.00000000000000	3,174	0.00000000000000	3,728	0.00000000000000	3,173	0.00000000000000
3,641	0.00000000000000	3,171	0.00000000000000	3,727	0.00000000000000	3,173	0.00000000000000
3,641	0.00000000000000	3,171	0.00000000000000	3,725	0.00000000000000	3,173	0.00000000000000
3,640	0.00000000000000	3,170	0.00000000000000	3,724	0.00000000000000	3,170	0.00000000000000
3,640	0.00000000000000	3,170	0.00000000000000	3,723	0.00000000000000	3,170	0.00000000000000
3,639	0.00000000000000	3,170	0.00000000000000	3,723	0.00000000000000	3,166	0.00000000000000
3,638	0.00000000000000	3,169	0.00000000000000	3,723	0.00000000000000	3,166	0.00000000000000
3,637	0.00000000000000	3,168	0.00000000000000	3,722	0.00000000000000	3,166	0.00000000000000
3,636	0.00000000000000	3,166	0.00000000000000	3,720	0.00000000000000	3,165	0.00000000000000
3,636	0.00000000000000	3,165	0.00000000000000	3,718	0.00000000000000	3,165	0.00000000000000
3,635	0.00000000000000	3,165	0.00000000000000	3,718	0.00000000000000	3,165	0.00000000000000
3,634	0.00000000000000	3,164	0.00000000000000	3,717	0.00000000000000	3,163	0.00000000000000
3,633	0.00000000000000	3,164	0.00000000000000	3,716	0.00000000000000	3,161	0.00000000000000
3,632	0.00000000000000	3,163	0.00000000000000	3,715	0.00000000000000	3,157	0.00000000000000
3,632	0.00000000000000	3,163	0.00000000000000	3,715	0.00000000000000	3,157	0.00000000000000
3,631	0.00000000000000	3,162	0.00000000000000	3,715	0.00000000000000	3,157	0.00000000000000
3,631	0.00000000000000	3,159	0.00000000000000	3,714	0.00000000000000	3,156	0.00000000000000
3,628	0.00000000000000	3,158	0.00000000000000	3,710	0.00000000000000	3,155	0.00000000000000
3,627	0.00000000000000	3,157	0.00000000000000	3,705	0.00000000000000	3,155	0.00000000000000
3,627	0.00000000000000	3,155	0.00000000000000	3,704	0.00000000000000	3,155	0.00000000000000
3,627	0.00000000000000	3,154	0.00000000000000	3,702	0.00000000000000	3,154	0.00000000000000
3,624	0.00000000000000	3,153	0.00000000000000	3,699	0.00000000000000	3,154	0.00000000000000
3,622	0.00000000000000	3,153	0.00000000000000	3,699	0.00000000000000	3,151	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,622	0.00000000000000	3,151	0.00000000000000	3,696	0.00000000000000	3,150	0.00000000000000
3,621	0.00000000000000	3,150	0.00000000000000	3,693	0.00000000000000	3,150	0.00000000000000
3,619	0.00000000000000	3,149	0.00000000000000	3,691	0.00000000000000	3,149	0.00000000000000
3,618	0.00000000000000	3,149	0.00000000000000	3,690	0.00000000000000	3,149	0.00000000000000
3,616	0.00000000000000	3,148	0.00000000000000	3,689	0.00000000000000	3,147	0.00000000000000
3,615	0.00000000000000	3,147	0.00000000000000	3,689	0.00000000000000	3,147	0.00000000000000
3,615	0.00000000000000	3,146	0.00000000000000	3,689	0.00000000000000	3,146	0.00000000000000
3,615	0.00000000000000	3,145	0.00000000000000	3,689	0.00000000000000	3,145	0.00000000000000
3,613	0.00000000000000	3,145	0.00000000000000	3,688	0.00000000000000	3,144	0.00000000000000
3,613	0.00000000000000	3,143	0.00000000000000	3,687	0.00000000000000	3,142	0.00000000000000
3,612	0.00000000000000	3,142	0.00000000000000	3,686	0.00000000000000	3,142	0.00000000000000
3,609	0.00000000000000	3,141	0.00000000000000	3,685	0.00000000000000	3,142	0.00000000000000
3,609	0.00000000000000	3,139	0.00000000000000	3,685	0.00000000000000	3,140	0.00000000000000
3,609	0.00000000000000	3,139	0.00000000000000	3,683	0.00000000000000	3,139	0.00000000000000
3,607	0.00000000000000	3,139	0.00000000000000	3,682	0.00000000000000	3,138	0.00000000000000
3,607	0.00000000000000	3,138	0.00000000000000	3,682	0.00000000000000	3,138	0.00000000000000
3,606	0.00000000000000	3,137	0.00000000000000	3,681	0.00000000000000	3,137	0.00000000000000
3,606	0.00000000000000	3,137	0.00000000000000	3,680	0.00000000000000	3,136	0.00000000000000
3,606	0.00000000000000	3,136	0.00000000000000	3,680	0.00000000000000	3,135	0.00000000000000
3,605	0.00000000000000	3,136	0.00000000000000	3,680	0.00000000000000	3,135	0.00000000000000
3,604	0.00000000000000	3,135	0.00000000000000	3,679	0.00000000000000	3,134	0.00000000000000
3,603	0.00000000000000	3,134	0.00000000000000	3,678	0.00000000000000	3,134	0.00000000000000
3,603	0.00000000000000	3,134	0.00000000000000	3,677	0.00000000000000	3,133	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,603	0.00000000000000	3,132	0.00000000000000	3,675	0.00000000000000	3,133	0.00000000000000
3,602	0.00000000000000	3,132	0.00000000000000	3,674	0.00000000000000	3,133	0.00000000000000
3,602	0.00000000000000	3,131	0.00000000000000	3,673	0.00000000000000	3,132	0.00000000000000
3,601	0.00000000000000	3,130	0.00000000000000	3,672	0.00000000000000	3,130	0.00000000000000
3,600	0.00000000000000	3,130	0.00000000000000	3,672	0.00000000000000	3,128	0.00000000000000
3,598	0.00000000000000	3,130	0.00000000000000	3,672	0.00000000000000	3,126	0.00000000000000
3,598	0.00000000000000	3,130	0.00000000000000	3,669	0.00000000000000	3,126	0.00000000000000
3,598	0.00000000000000	3,126	0.00000000000000	3,665	0.00000000000000	3,125	0.00000000000000
3,597	0.00000000000000	3,126	0.00000000000000	3,664	0.00000000000000	3,124	0.00000000000000
3,596	0.00000000000000	3,126	0.00000000000000	3,664	0.00000000000000	3,123	0.00000000000000
3,596	0.00000000000000	3,125	0.00000000000000	3,664	0.00000000000000	3,123	0.00000000000000
3,596	0.00000000000000	3,125	0.00000000000000	3,663	0.00000000000000	3,121	0.00000000000000
3,595	0.00000000000000	3,123	0.00000000000000	3,662	0.00000000000000	3,121	0.00000000000000
3,594	0.00000000000000	3,122	0.00000000000000	3,661	0.00000000000000	3,120	0.00000000000000
3,590	0.00000000000000	3,121	0.00000000000000	3,660	0.00000000000000	3,120	0.00000000000000
3,589	0.00000000000000	3,121	0.00000000000000	3,659	0.00000000000000	3,119	0.00000000000000
3,589	0.00000000000000	3,120	0.00000000000000	3,655	0.00000000000000	3,118	0.00000000000000
3,588	0.00000000000000	3,120	0.00000000000000	3,653	0.00000000000000	3,116	0.00000000000000
3,588	0.00000000000000	3,119	0.00000000000000	3,651	0.00000000000000	3,113	0.00000000000000
3,587	0.00000000000000	3,119	0.00000000000000	3,651	0.00000000000000	3,112	0.00000000000000
3,587	0.00000000000000	3,119	0.00000000000000	3,650	0.00000000000000	3,112	0.00000000000000
3,586	0.00000000000000	3,119	0.00000000000000	3,647	0.00000000000000	3,112	0.00000000000000
3,584	0.00000000000000	3,118	0.00000000000000	3,647	0.00000000000000	3,109	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,584	0.00000000000000	3,117	0.00000000000000	3,647	0.00000000000000	3,109	0.00000000000000
3,583	0.00000000000000	3,117	0.00000000000000	3,646	0.00000000000000	3,108	0.00000000000000
3,582	0.00000000000000	3,117	0.00000000000000	3,645	0.00000000000000	3,108	0.00000000000000
3,582	0.00000000000000	3,117	0.00000000000000	3,644	0.00000000000000	3,107	0.00000000000000
3,581	0.00000000000000	3,116	0.00000000000000	3,642	0.00000000000000	3,107	0.00000000000000
3,580	0.00000000000000	3,115	0.00000000000000	3,640	0.00000000000000	3,105	0.00000000000000
3,579	0.00000000000000	3,114	0.00000000000000	3,639	0.00000000000000	3,105	0.00000000000000
3,575	0.00000000000000	3,114	0.00000000000000	3,639	0.00000000000000	3,105	0.00000000000000
3,572	0.00000000000000	3,114	0.00000000000000	3,639	0.00000000000000	3,104	0.00000000000000
3,569	0.00000000000000	3,113	0.00000000000000	3,637	0.00000000000000	3,104	0.00000000000000
3,568	0.00000000000000	3,113	0.00000000000000	3,637	0.00000000000000	3,103	0.00000000000000
3,567	0.00000000000000	3,110	0.00000000000000	3,637	0.00000000000000	3,101	0.00000000000000
3,567	0.00000000000000	3,109	0.00000000000000	3,637	0.00000000000000	3,100	0.00000000000000
3,567	0.00000000000000	3,108	0.00000000000000	3,630	0.00000000000000	3,099	0.00000000000000
3,566	0.00000000000000	3,108	0.00000000000000	3,629	0.00000000000000	3,098	0.00000000000000
3,566	0.00000000000000	3,108	0.00000000000000	3,628	0.00000000000000	3,097	0.00000000000000
3,566	0.00000000000000	3,105	0.00000000000000	3,627	0.00000000000000	3,096	0.00000000000000
3,565	0.00000000000000	3,105	0.00000000000000	3,626	0.00000000000000	3,094	0.00000000000000
3,564	0.00000000000000	3,105	0.00000000000000	3,625	0.00000000000000	3,094	0.00000000000000
3,564	0.00000000000000	3,105	0.00000000000000	3,624	0.00000000000000	3,094	0.00000000000000
3,562	0.00000000000000	3,104	0.00000000000000	3,624	0.00000000000000	3,091	0.00000000000000
3,562	0.00000000000000	3,104	0.00000000000000	3,623	0.00000000000000	3,091	0.00000000000000
3,562	0.00000000000000	3,103	0.00000000000000	3,622	0.00000000000000	3,088	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,561	0.00000000000000	3,103	0.00000000000000	3,622	0.00000000000000	3,085	0.00000000000000
3,560	0.00000000000000	3,101	0.00000000000000	3,622	0.00000000000000	3,085	0.00000000000000
3,557	0.00000000000000	3,101	0.00000000000000	3,621	0.00000000000000	3,085	0.00000000000000
3,556	0.00000000000000	3,098	0.00000000000000	3,621	0.00000000000000	3,085	0.00000000000000
3,555	0.00000000000000	3,097	0.00000000000000	3,617	0.00000000000000	3,084	0.00000000000000
3,555	0.00000000000000	3,095	0.00000000000000	3,615	0.00000000000000	3,084	0.00000000000000
3,555	0.00000000000000	3,095	0.00000000000000	3,615	0.00000000000000	3,084	0.00000000000000
3,555	0.00000000000000	3,095	0.00000000000000	3,614	0.00000000000000	3,084	0.00000000000000
3,555	0.00000000000000	3,094	0.00000000000000	3,611	0.00000000000000	3,080	0.00000000000000
3,554	0.00000000000000	3,093	0.00000000000000	3,610	0.00000000000000	3,079	0.00000000000000
3,553	0.00000000000000	3,093	0.00000000000000	3,610	0.00000000000000	3,079	0.00000000000000
3,552	0.00000000000000	3,091	0.00000000000000	3,610	0.00000000000000	3,078	0.00000000000000
3,552	0.00000000000000	3,091	0.00000000000000	3,607	0.00000000000000	3,076	0.00000000000000
3,550	0.00000000000000	3,091	0.00000000000000	3,605	0.00000000000000	3,076	0.00000000000000
3,549	0.00000000000000	3,091	0.00000000000000	3,602	0.00000000000000	3,076	0.00000000000000
3,548	0.00000000000000	3,087	0.00000000000000	3,601	0.00000000000000	3,073	0.00000000000000
3,547	0.00000000000000	3,086	0.00000000000000	3,600	0.00000000000000	3,073	0.00000000000000
3,547	0.00000000000000	3,085	0.00000000000000	3,598	0.00000000000000	3,071	0.00000000000000
3,547	0.00000000000000	3,085	0.00000000000000	3,594	0.00000000000000	3,070	0.00000000000000
3,547	0.00000000000000	3,085	0.00000000000000	3,592	0.00000000000000	3,070	0.00000000000000
3,546	0.00000000000000	3,084	0.00000000000000	3,591	0.00000000000000	3,069	0.00000000000000
3,545	0.00000000000000	3,084	0.00000000000000	3,590	0.00000000000000	3,069	0.00000000000000
3,543	0.00000000000000	3,084	0.00000000000000	3,589	0.00000000000000	3,069	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,543	0.00000000000000	3,083	0.00000000000000	3,586	0.00000000000000	3,068	0.00000000000000
3,542	0.00000000000000	3,083	0.00000000000000	3,586	0.00000000000000	3,066	0.00000000000000
3,542	0.00000000000000	3,082	0.00000000000000	3,585	0.00000000000000	3,064	0.00000000000000
3,542	0.00000000000000	3,082	0.00000000000000	3,582	0.00000000000000	3,064	0.00000000000000
3,542	0.00000000000000	3,079	0.00000000000000	3,580	0.00000000000000	3,063	0.00000000000000
3,542	0.00000000000000	3,078	0.00000000000000	3,579	0.00000000000000	3,061	0.00000000000000
3,541	0.00000000000000	3,077	0.00000000000000	3,579	0.00000000000000	3,061	0.00000000000000
3,540	0.00000000000000	3,077	0.00000000000000	3,577	0.00000000000000	3,060	0.00000000000000
3,540	0.00000000000000	3,076	0.00000000000000	3,577	0.00000000000000	3,060	0.00000000000000
3,539	0.00000000000000	3,074	0.00000000000000	3,575	0.00000000000000	3,059	0.00000000000000
3,538	0.00000000000000	3,073	0.00000000000000	3,575	0.00000000000000	3,059	0.00000000000000
3,537	0.00000000000000	3,073	0.00000000000000	3,573	0.00000000000000	3,059	0.00000000000000
3,537	0.00000000000000	3,073	0.00000000000000	3,570	0.00000000000000	3,059	0.00000000000000
3,536	0.00000000000000	3,072	0.00000000000000	3,570	0.00000000000000	3,059	0.00000000000000
3,536	0.00000000000000	3,072	0.00000000000000	3,569	0.00000000000000	3,059	0.00000000000000
3,536	0.00000000000000	3,070	0.00000000000000	3,569	0.00000000000000	3,058	0.00000000000000
3,536	0.00000000000000	3,070	0.00000000000000	3,567	0.00000000000000	3,057	0.00000000000000
3,536	0.00000000000000	3,069	0.00000000000000	3,566	0.00000000000000	3,056	0.00000000000000
3,535	0.00000000000000	3,067	0.00000000000000	3,566	0.00000000000000	3,055	0.00000000000000
3,534	0.00000000000000	3,067	0.00000000000000	3,562	0.00000000000000	3,054	0.00000000000000
3,534	0.00000000000000	3,066	0.00000000000000	3,561	0.00000000000000	3,053	0.00000000000000
3,534	0.00000000000000	3,066	0.00000000000000	3,560	0.00000000000000	3,053	0.00000000000000
3,534	0.00000000000000	3,065	0.00000000000000	3,559	0.00000000000000	3,053	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,533	0.00000000000000	3,064	0.00000000000000	3,556	0.00000000000000	3,053	0.00000000000000
3,533	0.00000000000000	3,064	0.00000000000000	3,555	0.00000000000000	3,052	0.00000000000000
3,532	0.00000000000000	3,063	0.00000000000000	3,555	0.00000000000000	3,051	0.00000000000000
3,532	0.00000000000000	3,061	0.00000000000000	3,554	0.00000000000000	3,050	0.00000000000000
3,532	0.00000000000000	3,058	0.00000000000000	3,554	0.00000000000000	3,049	0.00000000000000
3,531	0.00000000000000	3,057	0.00000000000000	3,553	0.00000000000000	3,049	0.00000000000000
3,531	0.00000000000000	3,057	0.00000000000000	3,552	0.00000000000000	3,048	0.00000000000000
3,530	0.00000000000000	3,056	0.00000000000000	3,550	0.00000000000000	3,047	0.00000000000000
3,528	0.00000000000000	3,056	0.00000000000000	3,548	0.00000000000000	3,046	0.00000000000000
3,528	0.00000000000000	3,055	0.00000000000000	3,548	0.00000000000000	3,046	0.00000000000000
3,526	0.00000000000000	3,054	0.00000000000000	3,547	0.00000000000000	3,044	0.00000000000000
3,526	0.00000000000000	3,054	0.00000000000000	3,546	0.00000000000000	3,044	0.00000000000000
3,526	0.00000000000000	3,052	0.00000000000000	3,546	0.00000000000000	3,043	0.00000000000000
3,525	0.00000000000000	3,052	0.00000000000000	3,543	0.00000000000000	3,043	0.00000000000000
3,524	0.00000000000000	3,051	0.00000000000000	3,540	0.00000000000000	3,043	0.00000000000000
3,522	0.00000000000000	3,051	0.00000000000000	3,540	0.00000000000000	3,041	0.00000000000000
3,521	0.00000000000000	3,051	0.00000000000000	3,539	0.00000000000000	3,040	0.00000000000000
3,520	0.00000000000000	3,050	0.00000000000000	3,538	0.00000000000000	3,040	0.00000000000000
3,520	0.00000000000000	3,049	0.00000000000000	3,537	0.00000000000000	3,040	0.00000000000000
3,519	0.00000000000000	3,048	0.00000000000000	3,535	0.00000000000000	3,040	0.00000000000000
3,517	0.00000000000000	3,047	0.00000000000000	3,533	0.00000000000000	3,040	0.00000000000000
3,516	0.00000000000000	3,046	0.00000000000000	3,529	0.00000000000000	3,038	0.00000000000000
3,514	0.00000000000000	3,046	0.00000000000000	3,529	0.00000000000000	3,038	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,514	0.00000000000000	3,045	0.00000000000000	3,528	0.00000000000000	3,035	0.00000000000000
3,513	0.00000000000000	3,045	0.00000000000000	3,528	0.00000000000000	3,034	0.00000000000000
3,512	0.00000000000000	3,045	0.00000000000000	3,528	0.00000000000000	3,034	0.00000000000000
3,511	0.00000000000000	3,043	0.00000000000000	3,527	0.00000000000000	3,033	0.00000000000000
3,510	0.00000000000000	3,043	0.00000000000000	3,527	0.00000000000000	3,031	0.00000000000000
3,510	0.00000000000000	3,042	0.00000000000000	3,525	0.00000000000000	3,031	0.00000000000000
3,508	0.00000000000000	3,042	0.00000000000000	3,525	0.00000000000000	3,030	0.00000000000000
3,508	0.00000000000000	3,040	0.00000000000000	3,524	0.00000000000000	3,030	0.00000000000000
3,507	0.00000000000000	3,040	0.00000000000000	3,522	0.00000000000000	3,029	0.00000000000000
3,505	0.00000000000000	3,040	0.00000000000000	3,521	0.00000000000000	3,028	0.00000000000000
3,504	0.00000000000000	3,040	0.00000000000000	3,517	0.00000000000000	3,027	0.00000000000000
3,504	0.00000000000000	3,037	0.00000000000000	3,516	0.00000000000000	3,027	0.00000000000000
3,503	0.00000000000000	3,036	0.00000000000000	3,515	0.00000000000000	3,027	0.00000000000000
3,502	0.00000000000000	3,036	0.00000000000000	3,515	0.00000000000000	3,026	0.00000000000000
3,502	0.00000000000000	3,035	0.00000000000000	3,515	0.00000000000000	3,026	0.00000000000000
3,502	0.00000000000000	3,034	0.00000000000000	3,515	0.00000000000000	3,025	0.00000000000000
3,500	0.00000000000000	3,034	0.00000000000000	3,515	0.00000000000000	3,024	0.00000000000000
3,499	0.00000000000000	3,034	0.00000000000000	3,514	0.00000000000000	3,023	0.00000000000000
3,499	0.00000000000000	3,033	0.00000000000000	3,513	0.00000000000000	3,023	0.00000000000000
3,499	0.00000000000000	3,033	0.00000000000000	3,513	0.00000000000000	3,020	0.00000000000000
3,498	0.00000000000000	3,032	0.00000000000000	3,511	0.00000000000000	3,020	0.00000000000000
3,497	0.00000000000000	3,032	0.00000000000000	3,511	0.00000000000000	3,019	0.00000000000000
3,497	0.00000000000000	3,031	0.00000000000000	3,510	0.00000000000000	3,018	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,496	0.00000000000000	3,029	0.00000000000000	3,509	0.00000000000000	3,018	0.00000000000000
3,496	0.00000000000000	3,029	0.00000000000000	3,508	0.00000000000000	3,018	0.00000000000000
3,496	0.00000000000000	3,028	0.00000000000000	3,507	0.00000000000000	3,018	0.00000000000000
3,495	0.00000000000000	3,025	0.00000000000000	3,507	0.00000000000000	3,016	0.00000000000000
3,494	0.00000000000000	3,025	0.00000000000000	3,507	0.00000000000000	3,014	0.00000000000000
3,494	0.00000000000000	3,024	0.00000000000000	3,507	0.00000000000000	3,014	0.00000000000000
3,493	0.00000000000000	3,023	0.00000000000000	3,506	0.00000000000000	3,013	0.00000000000000
3,491	0.00000000000000	3,021	0.00000000000000	3,506	0.00000000000000	3,013	0.00000000000000
3,491	0.00000000000000	3,020	0.00000000000000	3,503	0.00000000000000	3,013	0.00000000000000
3,490	0.00000000000000	3,020	0.00000000000000	3,502	0.00000000000000	3,012	0.00000000000000
3,490	0.00000000000000	3,019	0.00000000000000	3,501	0.00000000000000	3,010	0.00000000000000
3,489	0.00000000000000	3,018	0.00000000000000	3,501	0.00000000000000	3,009	0.00000000000000
3,488	0.00000000000000	3,017	0.00000000000000	3,498	0.00000000000000	3,009	0.00000000000000
3,488	0.00000000000000	3,017	0.00000000000000	3,497	0.00000000000000	3,008	0.00000000000000
3,487	0.00000000000000	3,016	0.00000000000000	3,495	0.00000000000000	3,006	0.00000000000000
3,487	0.00000000000000	3,016	0.00000000000000	3,494	0.00000000000000	3,005	0.00000000000000
3,487	0.00000000000000	3,015	0.00000000000000	3,492	0.00000000000000	3,004	0.00000000000000
3,484	0.00000000000000	3,015	0.00000000000000	3,491	0.00000000000000	3,003	0.00000000000000
3,483	0.00000000000000	3,014	0.00000000000000	3,490	0.00000000000000	3,002	0.00000000000000
3,482	0.00000000000000	3,013	0.00000000000000	3,490	0.00000000000000	3,001	0.00000000000000
3,480	0.00000000000000	3,012	0.00000000000000	3,488	0.00000000000000	3,000	0.00000000000000
3,480	0.00000000000000	3,011	0.00000000000000	3,488	0.00000000000000	3,000	0.00000000000000
3,480	0.00000000000000	3,009	0.00000000000000	3,487	0.00000000000000	2,999	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,479	0.00000000000000	3,008	0.00000000000000	3,487	0.00000000000000	2,998	0.00000000000000
3,478	0.00000000000000	3,007	0.00000000000000	3,485	0.00000000000000	2,994	0.00000000000000
3,478	0.00000000000000	3,002	0.00000000000000	3,485	0.00000000000000	2,991	0.00000000000000
3,477	0.00000000000000	3,001	0.00000000000000	3,482	0.00000000000000	2,991	0.00000000000000
3,476	0.00000000000000	3,001	0.00000000000000	3,481	0.00000000000000	2,990	0.00000000000000
3,476	0.00000000000000	3,001	0.00000000000000	3,481	0.00000000000000	2,989	0.00000000000000
3,475	0.00000000000000	3,000	0.00000000000000	3,480	0.00000000000000	2,989	0.00000000000000
3,475	0.00000000000000	3,000	0.00000000000000	3,480	0.00000000000000	2,988	0.00000000000000
3,475	0.00000000000000	2,999	0.00000000000000	3,480	0.00000000000000	2,988	0.00000000000000
3,474	0.00000000000000	2,999	0.00000000000000	3,478	0.00000000000000	2,988	0.00000000000000
3,474	0.00000000000000	2,999	0.00000000000000	3,477	0.00000000000000	2,985	0.00000000000000
3,473	0.00000000000000	2,999	0.00000000000000	3,477	0.00000000000000	2,985	0.00000000000000
3,473	0.00000000000000	2,998	0.00000000000000	3,475	0.00000000000000	2,984	0.00000000000000
3,473	0.00000000000000	2,998	0.00000000000000	3,472	0.00000000000000	2,984	0.00000000000000
3,469	0.00000000000000	2,998	0.00000000000000	3,470	0.00000000000000	2,983	0.00000000000000
3,466	0.00000000000000	2,998	0.00000000000000	3,469	0.00000000000000	2,983	0.00000000000000
3,466	0.00000000000000	2,996	0.00000000000000	3,469	0.00000000000000	2,982	0.00000000000000
3,464	0.00000000000000	2,996	0.00000000000000	3,466	0.00000000000000	2,981	0.00000000000000
3,463	0.00000000000000	2,996	0.00000000000000	3,464	0.00000000000000	2,980	0.00000000000000
3,463	0.00000000000000	2,996	0.00000000000000	3,462	0.00000000000000	2,980	0.00000000000000
3,463	0.00000000000000	2,995	0.00000000000000	3,461	0.00000000000000	2,978	0.00000000000000
3,462	0.00000000000000	2,994	0.00000000000000	3,458	0.00000000000000	2,978	0.00000000000000
3,460	0.00000000000000	2,994	0.00000000000000	3,457	0.00000000000000	2,975	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,458	0.00000000000000	2,993	0.00000000000000	3,456	0.00000000000000	2,975	0.00000000000000
3,457	0.00000000000000	2,992	0.00000000000000	3,454	0.00000000000000	2,973	0.00000000000000
3,457	0.00000000000000	2,991	0.00000000000000	3,451	0.00000000000000	2,973	0.00000000000000
3,457	0.00000000000000	2,988	0.00000000000000	3,450	0.00000000000000	2,972	0.00000000000000
3,456	0.00000000000000	2,988	0.00000000000000	3,449	0.00000000000000	2,972	0.00000000000000
3,453	0.00000000000000	2,987	0.00000000000000	3,448	0.00000000000000	2,970	0.00000000000000
3,453	0.00000000000000	2,986	0.00000000000000	3,448	0.00000000000000	2,970	0.00000000000000
3,450	0.00000000000000	2,985	0.00000000000000	3,444	0.00000000000000	2,967	0.00000000000000
3,450	0.00000000000000	2,984	0.00000000000000	3,443	0.00000000000000	2,966	0.00000000000000
3,449	0.00000000000000	2,984	0.00000000000000	3,442	0.00000000000000	2,966	0.00000000000000
3,449	0.00000000000000	2,984	0.00000000000000	3,441	0.00000000000000	2,964	0.00000000000000
3,448	0.00000000000000	2,982	0.00000000000000	3,440	0.00000000000000	2,963	0.00000000000000
3,446	0.00000000000000	2,981	0.00000000000000	3,440	0.00000000000000	2,962	0.00000000000000
3,446	0.00000000000000	2,981	0.00000000000000	3,440	0.00000000000000	2,962	0.00000000000000
3,444	0.00000000000000	2,980	0.00000000000000	3,438	0.00000000000000	2,962	0.00000000000000
3,443	0.00000000000000	2,979	0.00000000000000	3,438	0.00000000000000	2,961	0.00000000000000
3,443	0.00000000000000	2,979	0.00000000000000	3,434	0.00000000000000	2,959	0.00000000000000
3,443	0.00000000000000	2,978	0.00000000000000	3,433	0.00000000000000	2,959	0.00000000000000
3,443	0.00000000000000	2,978	0.00000000000000	3,433	0.00000000000000	2,959	0.00000000000000
3,442	0.00000000000000	2,978	0.00000000000000	3,430	0.00000000000000	2,957	0.00000000000000
3,442	0.00000000000000	2,978	0.00000000000000	3,428	0.00000000000000	2,957	0.00000000000000
3,441	0.00000000000000	2,978	0.00000000000000	3,427	0.00000000000000	2,956	0.00000000000000
3,441	0.00000000000000	2,976	0.00000000000000	3,426	0.00000000000000	2,956	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,438	0.00000000000000	2,976	0.00000000000000	3,425	0.00000000000000	2,955	0.00000000000000
3,438	0.00000000000000	2,975	0.00000000000000	3,424	0.00000000000000	2,954	0.00000000000000
3,436	0.00000000000000	2,975	0.00000000000000	3,422	0.00000000000000	2,953	0.00000000000000
3,435	0.00000000000000	2,975	0.00000000000000	3,421	0.00000000000000	2,951	0.00000000000000
3,434	0.00000000000000	2,974	0.00000000000000	3,418	0.00000000000000	2,950	0.00000000000000
3,433	0.00000000000000	2,973	0.00000000000000	3,418	0.00000000000000	2,949	0.00000000000000
3,433	0.00000000000000	2,972	0.00000000000000	3,414	0.00000000000000	2,948	0.00000000000000
3,432	0.00000000000000	2,971	0.00000000000000	3,412	0.00000000000000	2,947	0.00000000000000
3,432	0.00000000000000	2,971	0.00000000000000	3,412	0.00000000000000	2,946	0.00000000000000
3,432	0.00000000000000	2,966	0.00000000000000	3,412	0.00000000000000	2,945	0.00000000000000
3,432	0.00000000000000	2,966	0.00000000000000	3,410	0.00000000000000	2,945	0.00000000000000
3,431	0.00000000000000	2,963	0.00000000000000	3,407	0.00000000000000	2,945	0.00000000000000
3,431	0.00000000000000	2,963	0.00000000000000	3,406	0.00000000000000	2,944	0.00000000000000
3,430	0.00000000000000	2,961	0.00000000000000	3,405	0.00000000000000	2,942	0.00000000000000
3,429	0.00000000000000	2,960	0.00000000000000	3,403	0.00000000000000	2,942	0.00000000000000
3,428	0.00000000000000	2,959	0.00000000000000	3,403	0.00000000000000	2,941	0.00000000000000
3,428	0.00000000000000	2,958	0.00000000000000	3,402	0.00000000000000	2,941	0.00000000000000
3,428	0.00000000000000	2,957	0.00000000000000	3,402	0.00000000000000	2,939	0.00000000000000
3,427	0.00000000000000	2,956	0.00000000000000	3,402	0.00000000000000	2,939	0.00000000000000
3,426	0.00000000000000	2,955	0.00000000000000	3,401	0.00000000000000	2,937	0.00000000000000
3,425	0.00000000000000	2,954	0.00000000000000	3,400	0.00000000000000	2,935	0.00000000000000
3,424	0.00000000000000	2,953	0.00000000000000	3,398	0.00000000000000	2,935	0.00000000000000
3,424	0.00000000000000	2,952	0.00000000000000	3,396	0.00000000000000	2,933	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**	**System Load Level (MW)**	**Loss of Load Probability**
3,423	0.00000000000000	2,952	0.00000000000000	3,395	0.00000000000000	2,931	0.00000000000000
3,422	0.00000000000000	2,952	0.00000000000000	3,395	0.00000000000000	2,931	0.00000000000000
3,422	0.00000000000000	2,952	0.00000000000000	3,394	0.00000000000000	2,930	0.00000000000000
3,422	0.00000000000000	2,951	0.00000000000000	3,394	0.00000000000000	2,930	0.00000000000000
3,421	0.00000000000000	2,950	0.00000000000000	3,393	0.00000000000000	2,930	0.00000000000000
3,421	0.00000000000000	2,950	0.00000000000000	3,393	0.00000000000000	2,928	0.00000000000000
3,421	0.00000000000000	2,949	0.00000000000000	3,391	0.00000000000000	2,927	0.00000000000000
3,418	0.00000000000000	2,948	0.00000000000000	3,390	0.00000000000000	2,927	0.00000000000000
3,417	0.00000000000000	2,948	0.00000000000000	3,388	0.00000000000000	2,927	0.00000000000000
3,415	0.00000000000000	2,948	0.00000000000000	3,388	0.00000000000000	2,925	0.00000000000000
3,413	0.00000000000000	2,945	0.00000000000000	3,386	0.00000000000000	2,924	0.00000000000000
3,412	0.00000000000000	2,943	0.00000000000000	3,384	0.00000000000000	2,923	0.00000000000000
3,412	0.00000000000000	2,943	0.00000000000000	3,384	0.00000000000000	2,923	0.00000000000000
3,411	0.00000000000000	2,942	0.00000000000000	3,383	0.00000000000000	2,923	0.00000000000000
3,411	0.00000000000000	2,942	0.00000000000000	3,382	0.00000000000000	2,923	0.00000000000000
3,411	0.00000000000000	2,942	0.00000000000000	3,382	0.00000000000000	2,921	0.00000000000000
3,410	0.00000000000000	2,941	0.00000000000000	3,378	0.00000000000000	2,919	0.00000000000000
3,409	0.00000000000000	2,940	0.00000000000000	3,378	0.00000000000000	2,919	0.00000000000000
3,409	0.00000000000000	2,940	0.00000000000000	3,372	0.00000000000000	2,919	0.00000000000000
3,409	0.00000000000000	2,940	0.00000000000000	3,372	0.00000000000000	2,918	0.00000000000000
3,407	0.00000000000000	2,939	0.00000000000000	3,372	0.00000000000000	2,917	0.00000000000000
3,406	0.00000000000000	2,938	0.00000000000000	3,369	0.00000000000000	2,916	0.00000000000000
3,403	0.00000000000000	2,937	0.00000000000000	3,369	0.00000000000000	2,916	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,402	0.00000000000000	2,936	0.00000000000000	3,362	0.00000000000000	2,915	0.00000000000000
3,401	0.00000000000000	2,936	0.00000000000000	3,360	0.00000000000000	2,915	0.00000000000000
3,399	0.00000000000000	2,936	0.00000000000000	3,359	0.00000000000000	2,913	0.00000000000000
3,399	0.00000000000000	2,935	0.00000000000000	3,358	0.00000000000000	2,912	0.00000000000000
3,396	0.00000000000000	2,935	0.00000000000000	3,358	0.00000000000000	2,911	0.00000000000000
3,395	0.00000000000000	2,935	0.00000000000000	3,356	0.00000000000000	2,910	0.00000000000000
3,394	0.00000000000000	2,934	0.00000000000000	3,355	0.00000000000000	2,910	0.00000000000000
3,393	0.00000000000000	2,933	0.00000000000000	3,354	0.00000000000000	2,909	0.00000000000000
3,392	0.00000000000000	2,933	0.00000000000000	3,353	0.00000000000000	2,909	0.00000000000000
3,392	0.00000000000000	2,933	0.00000000000000	3,347	0.00000000000000	2,908	0.00000000000000
3,391	0.00000000000000	2,931	0.00000000000000	3,346	0.00000000000000	2,908	0.00000000000000
3,389	0.00000000000000	2,930	0.00000000000000	3,346	0.00000000000000	2,908	0.00000000000000
3,388	0.00000000000000	2,930	0.00000000000000	3,345	0.00000000000000	2,905	0.00000000000000
3,387	0.00000000000000	2,929	0.00000000000000	3,344	0.00000000000000	2,905	0.00000000000000
3,386	0.00000000000000	2,928	0.00000000000000	3,342	0.00000000000000	2,904	0.00000000000000
3,385	0.00000000000000	2,924	0.00000000000000	3,342	0.00000000000000	2,903	0.00000000000000
3,385	0.00000000000000	2,924	0.00000000000000	3,341	0.00000000000000	2,901	0.00000000000000
3,383	0.00000000000000	2,923	0.00000000000000	3,338	0.00000000000000	2,898	0.00000000000000
3,382	0.00000000000000	2,923	0.00000000000000	3,338	0.00000000000000	2,897	0.00000000000000
3,382	0.00000000000000	2,921	0.00000000000000	3,338	0.00000000000000	2,897	0.00000000000000
3,380	0.00000000000000	2,920	0.00000000000000	3,337	0.00000000000000	2,897	0.00000000000000
3,378	0.00000000000000	2,919	0.00000000000000	3,330	0.00000000000000	2,895	0.00000000000000
3,376	0.00000000000000	2,918	0.00000000000000	3,328	0.00000000000000	2,894	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,375	0.00000000000000	2,917	0.00000000000000	3,327	0.00000000000000	2,894	0.00000000000000
3,374	0.00000000000000	2,916	0.00000000000000	3,326	0.00000000000000	2,893	0.00000000000000
3,373	0.00000000000000	2,916	0.00000000000000	3,326	0.00000000000000	2,893	0.00000000000000
3,373	0.00000000000000	2,915	0.00000000000000	3,324	0.00000000000000	2,892	0.00000000000000
3,373	0.00000000000000	2,914	0.00000000000000	3,324	0.00000000000000	2,891	0.00000000000000
3,373	0.00000000000000	2,913	0.00000000000000	3,322	0.00000000000000	2,890	0.00000000000000
3,372	0.00000000000000	2,912	0.00000000000000	3,321	0.00000000000000	2,890	0.00000000000000
3,370	0.00000000000000	2,912	0.00000000000000	3,318	0.00000000000000	2,890	0.00000000000000
3,369	0.00000000000000	2,911	0.00000000000000	3,318	0.00000000000000	2,889	0.00000000000000
3,368	0.00000000000000	2,911	0.00000000000000	3,316	0.00000000000000	2,888	0.00000000000000
3,367	0.00000000000000	2,909	0.00000000000000	3,315	0.00000000000000	2,888	0.00000000000000
3,366	0.00000000000000	2,908	0.00000000000000	3,314	0.00000000000000	2,887	0.00000000000000
3,366	0.00000000000000	2,908	0.00000000000000	3,313	0.00000000000000	2,887	0.00000000000000
3,366	0.00000000000000	2,907	0.00000000000000	3,312	0.00000000000000	2,885	0.00000000000000
3,365	0.00000000000000	2,907	0.00000000000000	3,312	0.00000000000000	2,884	0.00000000000000
3,365	0.00000000000000	2,906	0.00000000000000	3,311	0.00000000000000	2,884	0.00000000000000
3,365	0.00000000000000	2,901	0.00000000000000	3,308	0.00000000000000	2,882	0.00000000000000
3,364	0.00000000000000	2,900	0.00000000000000	3,308	0.00000000000000	2,882	0.00000000000000
3,363	0.00000000000000	2,899	0.00000000000000	3,307	0.00000000000000	2,882	0.00000000000000
3,362	0.00000000000000	2,897	0.00000000000000	3,307	0.00000000000000	2,881	0.00000000000000
3,362	0.00000000000000	2,897	0.00000000000000	3,304	0.00000000000000	2,875	0.00000000000000
3,361	0.00000000000000	2,897	0.00000000000000	3,303	0.00000000000000	2,874	0.00000000000000
3,361	0.00000000000000	2,896	0.00000000000000	3,302	0.00000000000000	2,872	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,361	0.00000000000000	2,896	0.00000000000000	3,301	0.00000000000000	2,869	0.00000000000000
3,360	0.00000000000000	2,896	0.00000000000000	3,301	0.00000000000000	2,868	0.00000000000000
3,358	0.00000000000000	2,896	0.00000000000000	3,301	0.00000000000000	2,867	0.00000000000000
3,358	0.00000000000000	2,895	0.00000000000000	3,300	0.00000000000000	2,867	0.00000000000000
3,357	0.00000000000000	2,893	0.00000000000000	3,300	0.00000000000000	2,864	0.00000000000000
3,357	0.00000000000000	2,893	0.00000000000000	3,300	0.00000000000000	2,863	0.00000000000000
3,356	0.00000000000000	2,892	0.00000000000000	3,299	0.00000000000000	2,863	0.00000000000000
3,356	0.00000000000000	2,891	0.00000000000000	3,298	0.00000000000000	2,863	0.00000000000000
3,355	0.00000000000000	2,891	0.00000000000000	3,298	0.00000000000000	2,863	0.00000000000000
3,354	0.00000000000000	2,891	0.00000000000000	3,298	0.00000000000000	2,862	0.00000000000000
3,352	0.00000000000000	2,889	0.00000000000000	3,297	0.00000000000000	2,862	0.00000000000000
3,351	0.00000000000000	2,889	0.00000000000000	3,296	0.00000000000000	2,860	0.00000000000000
3,350	0.00000000000000	2,888	0.00000000000000	3,296	0.00000000000000	2,860	0.00000000000000
3,349	0.00000000000000	2,888	0.00000000000000	3,295	0.00000000000000	2,858	0.00000000000000
3,349	0.00000000000000	2,887	0.00000000000000	3,292	0.00000000000000	2,858	0.00000000000000
3,348	0.00000000000000	2,886	0.00000000000000	3,291	0.00000000000000	2,858	0.00000000000000
3,347	0.00000000000000	2,885	0.00000000000000	3,291	0.00000000000000	2,858	0.00000000000000
3,345	0.00000000000000	2,885	0.00000000000000	3,289	0.00000000000000	2,857	0.00000000000000
3,345	0.00000000000000	2,885	0.00000000000000	3,287	0.00000000000000	2,857	0.00000000000000
3,343	0.00000000000000	2,883	0.00000000000000	3,287	0.00000000000000	2,857	0.00000000000000
3,341	0.00000000000000	2,883	0.00000000000000	3,285	0.00000000000000	2,856	0.00000000000000
3,341	0.00000000000000	2,883	0.00000000000000	3,283	0.00000000000000	2,854	0.00000000000000
3,340	0.00000000000000	2,883	0.00000000000000	3,283	0.00000000000000	2,852	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,340	0.00000000000000	2,882	0.00000000000000	3,281	0.00000000000000	2,852	0.00000000000000
3,339	0.00000000000000	2,881	0.00000000000000	3,280	0.00000000000000	2,849	0.00000000000000
3,339	0.00000000000000	2,880	0.00000000000000	3,279	0.00000000000000	2,849	0.00000000000000
3,338	0.00000000000000	2,880	0.00000000000000	3,277	0.00000000000000	2,848	0.00000000000000
3,338	0.00000000000000	2,879	0.00000000000000	3,277	0.00000000000000	2,847	0.00000000000000
3,337	0.00000000000000	2,878	0.00000000000000	3,276	0.00000000000000	2,846	0.00000000000000
3,337	0.00000000000000	2,877	0.00000000000000	3,274	0.00000000000000	2,843	0.00000000000000
3,336	0.00000000000000	2,876	0.00000000000000	3,274	0.00000000000000	2,843	0.00000000000000
3,335	0.00000000000000	2,875	0.00000000000000	3,268	0.00000000000000	2,841	0.00000000000000
3,335	0.00000000000000	2,869	0.00000000000000	3,267	0.00000000000000	2,840	0.00000000000000
3,335	0.00000000000000	2,868	0.00000000000000	3,267	0.00000000000000	2,838	0.00000000000000
3,333	0.00000000000000	2,868	0.00000000000000	3,266	0.00000000000000	2,838	0.00000000000000
3,333	0.00000000000000	2,867	0.00000000000000	3,266	0.00000000000000	2,838	0.00000000000000
3,331	0.00000000000000	2,866	0.00000000000000	3,266	0.00000000000000	2,837	0.00000000000000
3,327	0.00000000000000	2,865	0.00000000000000	3,265	0.00000000000000	2,836	0.00000000000000
3,326	0.00000000000000	2,864	0.00000000000000	3,264	0.00000000000000	2,835	0.00000000000000
3,326	0.00000000000000	2,864	0.00000000000000	3,264	0.00000000000000	2,835	0.00000000000000
3,324	0.00000000000000	2,862	0.00000000000000	3,263	0.00000000000000	2,835	0.00000000000000
3,322	0.00000000000000	2,862	0.00000000000000	3,262	0.00000000000000	2,834	0.00000000000000
3,322	0.00000000000000	2,861	0.00000000000000	3,261	0.00000000000000	2,834	0.00000000000000
3,320	0.00000000000000	2,859	0.00000000000000	3,260	0.00000000000000	2,833	0.00000000000000
3,320	0.00000000000000	2,859	0.00000000000000	3,255	0.00000000000000	2,833	0.00000000000000
3,320	0.00000000000000	2,858	0.00000000000000	3,255	0.00000000000000	2,833	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,319	0.00000000000000	2,856	0.00000000000000	3,254	0.00000000000000	2,830	0.00000000000000
3,319	0.00000000000000	2,855	0.00000000000000	3,253	0.00000000000000	2,830	0.00000000000000
3,313	0.00000000000000	2,853	0.00000000000000	3,252	0.00000000000000	2,829	0.00000000000000
3,308	0.00000000000000	2,852	0.00000000000000	3,251	0.00000000000000	2,828	0.00000000000000
3,308	0.00000000000000	2,851	0.00000000000000	3,249	0.00000000000000	2,828	0.00000000000000
3,308	0.00000000000000	2,851	0.00000000000000	3,249	0.00000000000000	2,827	0.00000000000000
3,308	0.00000000000000	2,850	0.00000000000000	3,249	0.00000000000000	2,827	0.00000000000000
3,307	0.00000000000000	2,850	0.00000000000000	3,246	0.00000000000000	2,826	0.00000000000000
3,306	0.00000000000000	2,848	0.00000000000000	3,245	0.00000000000000	2,826	0.00000000000000
3,306	0.00000000000000	2,848	0.00000000000000	3,244	0.00000000000000	2,824	0.00000000000000
3,304	0.00000000000000	2,848	0.00000000000000	3,244	0.00000000000000	2,823	0.00000000000000
3,303	0.00000000000000	2,848	0.00000000000000	3,242	0.00000000000000	2,822	0.00000000000000
3,302	0.00000000000000	2,847	0.00000000000000	3,242	0.00000000000000	2,821	0.00000000000000
3,302	0.00000000000000	2,847	0.00000000000000	3,242	0.00000000000000	2,821	0.00000000000000
3,300	0.00000000000000	2,846	0.00000000000000	3,242	0.00000000000000	2,819	0.00000000000000
3,300	0.00000000000000	2,846	0.00000000000000	3,240	0.00000000000000	2,818	0.00000000000000
3,299	0.00000000000000	2,846	0.00000000000000	3,239	0.00000000000000	2,817	0.00000000000000
3,299	0.00000000000000	2,845	0.00000000000000	3,236	0.00000000000000	2,815	0.00000000000000
3,298	0.00000000000000	2,845	0.00000000000000	3,235	0.00000000000000	2,814	0.00000000000000
3,298	0.00000000000000	2,844	0.00000000000000	3,233	0.00000000000000	2,813	0.00000000000000
3,295	0.00000000000000	2,843	0.00000000000000	3,230	0.00000000000000	2,812	0.00000000000000
3,295	0.00000000000000	2,843	0.00000000000000	3,229	0.00000000000000	2,811	0.00000000000000
3,294	0.00000000000000	2,840	0.00000000000000	3,229	0.00000000000000	2,811	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,292	0.00000000000000	2,840	0.00000000000000	3,228	0.00000000000000	2,811	0.00000000000000
3,290	0.00000000000000	2,839	0.00000000000000	3,226	0.00000000000000	2,809	0.00000000000000
3,289	0.00000000000000	2,838	0.00000000000000	3,223	0.00000000000000	2,809	0.00000000000000
3,287	0.00000000000000	2,838	0.00000000000000	3,222	0.00000000000000	2,808	0.00000000000000
3,287	0.00000000000000	2,838	0.00000000000000	3,221	0.00000000000000	2,808	0.00000000000000
3,286	0.00000000000000	2,837	0.00000000000000	3,220	0.00000000000000	2,808	0.00000000000000
3,286	0.00000000000000	2,837	0.00000000000000	3,213	0.00000000000000	2,806	0.00000000000000
3,284	0.00000000000000	2,837	0.00000000000000	3,211	0.00000000000000	2,804	0.00000000000000
3,284	0.00000000000000	2,836	0.00000000000000	3,210	0.00000000000000	2,803	0.00000000000000
3,281	0.00000000000000	2,835	0.00000000000000	3,209	0.00000000000000	2,802	0.00000000000000
3,281	0.00000000000000	2,833	0.00000000000000	3,207	0.00000000000000	2,802	0.00000000000000
3,279	0.00000000000000	2,833	0.00000000000000	3,203	0.00000000000000	2,801	0.00000000000000
3,279	0.00000000000000	2,833	0.00000000000000	3,203	0.00000000000000	2,800	0.00000000000000
3,279	0.00000000000000	2,833	0.00000000000000	3,201	0.00000000000000	2,799	0.00000000000000
3,278	0.00000000000000	2,832	0.00000000000000	3,201	0.00000000000000	2,799	0.00000000000000
3,278	0.00000000000000	2,831	0.00000000000000	3,200	0.00000000000000	2,799	0.00000000000000
3,278	0.00000000000000	2,830	0.00000000000000	3,200	0.00000000000000	2,799	0.00000000000000
3,277	0.00000000000000	2,829	0.00000000000000	3,198	0.00000000000000	2,799	0.00000000000000
3,276	0.00000000000000	2,828	0.00000000000000	3,197	0.00000000000000	2,799	0.00000000000000
3,275	0.00000000000000	2,828	0.00000000000000	3,197	0.00000000000000	2,798	0.00000000000000
3,275	0.00000000000000	2,828	0.00000000000000	3,194	0.00000000000000	2,798	0.00000000000000
3,274	0.00000000000000	2,826	0.00000000000000	3,193	0.00000000000000	2,796	0.00000000000000
3,274	0.00000000000000	2,826	0.00000000000000	3,193	0.00000000000000	2,796	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,272	0.00000000000000	2,826	0.00000000000000	3,193	0.00000000000000	2,795	0.00000000000000
3,271	0.00000000000000	2,823	0.00000000000000	3,191	0.00000000000000	2,794	0.00000000000000
3,267	0.00000000000000	2,822	0.00000000000000	3,190	0.00000000000000	2,792	0.00000000000000
3,265	0.00000000000000	2,820	0.00000000000000	3,189	0.00000000000000	2,792	0.00000000000000
3,265	0.00000000000000	2,818	0.00000000000000	3,188	0.00000000000000	2,790	0.00000000000000
3,264	0.00000000000000	2,818	0.00000000000000	3,182	0.00000000000000	2,789	0.00000000000000
3,263	0.00000000000000	2,818	0.00000000000000	3,180	0.00000000000000	2,786	0.00000000000000
3,263	0.00000000000000	2,817	0.00000000000000	3,178	0.00000000000000	2,783	0.00000000000000
3,263	0.00000000000000	2,817	0.00000000000000	3,176	0.00000000000000	2,781	0.00000000000000
3,262	0.00000000000000	2,816	0.00000000000000	3,173	0.00000000000000	2,781	0.00000000000000
3,262	0.00000000000000	2,816	0.00000000000000	3,173	0.00000000000000	2,781	0.00000000000000
3,260	0.00000000000000	2,816	0.00000000000000	3,170	0.00000000000000	2,781	0.00000000000000
3,257	0.00000000000000	2,816	0.00000000000000	3,169	0.00000000000000	2,780	0.00000000000000
3,256	0.00000000000000	2,815	0.00000000000000	3,168	0.00000000000000	2,779	0.00000000000000
3,255	0.00000000000000	2,814	0.00000000000000	3,167	0.00000000000000	2,778	0.00000000000000
3,255	0.00000000000000	2,812	0.00000000000000	3,165	0.00000000000000	2,777	0.00000000000000
3,255	0.00000000000000	2,811	0.00000000000000	3,163	0.00000000000000	2,777	0.00000000000000
3,255	0.00000000000000	2,811	0.00000000000000	3,162	0.00000000000000	2,776	0.00000000000000
3,250	0.00000000000000	2,809	0.00000000000000	3,161	0.00000000000000	2,774	0.00000000000000
3,247	0.00000000000000	2,809	0.00000000000000	3,160	0.00000000000000	2,774	0.00000000000000
3,247	0.00000000000000	2,807	0.00000000000000	3,160	0.00000000000000	2,774	0.00000000000000
3,246	0.00000000000000	2,807	0.00000000000000	3,160	0.00000000000000	2,772	0.00000000000000
3,246	0.00000000000000	2,807	0.00000000000000	3,156	0.00000000000000	2,771	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,245	0.00000000000000	2,806	0.00000000000000	3,155	0.00000000000000	2,771	0.00000000000000
3,243	0.00000000000000	2,806	0.00000000000000	3,154	0.00000000000000	2,770	0.00000000000000
3,243	0.00000000000000	2,805	0.00000000000000	3,154	0.00000000000000	2,768	0.00000000000000
3,242	0.00000000000000	2,805	0.00000000000000	3,153	0.00000000000000	2,767	0.00000000000000
3,242	0.00000000000000	2,805	0.00000000000000	3,151	0.00000000000000	2,766	0.00000000000000
3,242	0.00000000000000	2,804	0.00000000000000	3,148	0.00000000000000	2,764	0.00000000000000
3,241	0.00000000000000	2,804	0.00000000000000	3,146	0.00000000000000	2,764	0.00000000000000
3,238	0.00000000000000	2,804	0.00000000000000	3,145	0.00000000000000	2,763	0.00000000000000
3,235	0.00000000000000	2,803	0.00000000000000	3,145	0.00000000000000	2,763	0.00000000000000
3,234	0.00000000000000	2,802	0.00000000000000	3,142	0.00000000000000	2,762	0.00000000000000
3,232	0.00000000000000	2,800	0.00000000000000	3,142	0.00000000000000	2,762	0.00000000000000
3,232	0.00000000000000	2,799	0.00000000000000	3,139	0.00000000000000	2,762	0.00000000000000
3,232	0.00000000000000	2,799	0.00000000000000	3,139	0.00000000000000	2,761	0.00000000000000
3,231	0.00000000000000	2,798	0.00000000000000	3,137	0.00000000000000	2,761	0.00000000000000
3,231	0.00000000000000	2,797	0.00000000000000	3,137	0.00000000000000	2,758	0.00000000000000
3,227	0.00000000000000	2,797	0.00000000000000	3,136	0.00000000000000	2,757	0.00000000000000
3,227	0.00000000000000	2,796	0.00000000000000	3,135	0.00000000000000	2,750	0.00000000000000
3,226	0.00000000000000	2,796	0.00000000000000	3,131	0.00000000000000	2,749	0.00000000000000
3,224	0.00000000000000	2,796	0.00000000000000	3,131	0.00000000000000	2,746	0.00000000000000
3,223	0.00000000000000	2,795	0.00000000000000	3,130	0.00000000000000	2,745	0.00000000000000
3,223	0.00000000000000	2,793	0.00000000000000	3,128	0.00000000000000	2,744	0.00000000000000
3,222	0.00000000000000	2,793	0.00000000000000	3,128	0.00000000000000	2,743	0.00000000000000
3,219	0.00000000000000	2,792	0.00000000000000	3,127	0.00000000000000	2,742	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,218	0.00000000000000	2,792	0.00000000000000	3,126	0.00000000000000	2,742	0.00000000000000
3,217	0.00000000000000	2,790	0.00000000000000	3,124	0.00000000000000	2,741	0.00000000000000
3,216	0.00000000000000	2,787	0.00000000000000	3,122	0.00000000000000	2,741	0.00000000000000
3,215	0.00000000000000	2,786	0.00000000000000	3,122	0.00000000000000	2,738	0.00000000000000
3,214	0.00000000000000	2,786	0.00000000000000	3,122	0.00000000000000	2,735	0.00000000000000
3,213	0.00000000000000	2,785	0.00000000000000	3,121	0.00000000000000	2,734	0.00000000000000
3,209	0.00000000000000	2,785	0.00000000000000	3,121	0.00000000000000	2,733	0.00000000000000
3,206	0.00000000000000	2,785	0.00000000000000	3,117	0.00000000000000	2,733	0.00000000000000
3,205	0.00000000000000	2,784	0.00000000000000	3,116	0.00000000000000	2,733	0.00000000000000
3,205	0.00000000000000	2,783	0.00000000000000	3,115	0.00000000000000	2,732	0.00000000000000
3,204	0.00000000000000	2,782	0.00000000000000	3,114	0.00000000000000	2,730	0.00000000000000
3,203	0.00000000000000	2,780	0.00000000000000	3,114	0.00000000000000	2,730	0.00000000000000
3,203	0.00000000000000	2,779	0.00000000000000	3,111	0.00000000000000	2,726	0.00000000000000
3,202	0.00000000000000	2,779	0.00000000000000	3,108	0.00000000000000	2,725	0.00000000000000
3,200	0.00000000000000	2,779	0.00000000000000	3,107	0.00000000000000	2,723	0.00000000000000
3,199	0.00000000000000	2,779	0.00000000000000	3,106	0.00000000000000	2,723	0.00000000000000
3,196	0.00000000000000	2,778	0.00000000000000	3,106	0.00000000000000	2,722	0.00000000000000
3,195	0.00000000000000	2,778	0.00000000000000	3,104	0.00000000000000	2,720	0.00000000000000
3,195	0.00000000000000	2,778	0.00000000000000	3,104	0.00000000000000	2,720	0.00000000000000
3,194	0.00000000000000	2,776	0.00000000000000	3,103	0.00000000000000	2,719	0.00000000000000
3,193	0.00000000000000	2,775	0.00000000000000	3,102	0.00000000000000	2,719	0.00000000000000
3,193	0.00000000000000	2,774	0.00000000000000	3,101	0.00000000000000	2,718	0.00000000000000
3,193	0.00000000000000	2,774	0.00000000000000	3,098	0.00000000000000	2,715	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,193	0.00000000000000	2,773	0.00000000000000	3,098	0.00000000000000	2,713	0.00000000000000
3,188	0.00000000000000	2,772	0.00000000000000	3,096	0.00000000000000	2,711	0.00000000000000
3,186	0.00000000000000	2,772	0.00000000000000	3,095	0.00000000000000	2,710	0.00000000000000
3,184	0.00000000000000	2,765	0.00000000000000	3,095	0.00000000000000	2,708	0.00000000000000
3,183	0.00000000000000	2,765	0.00000000000000	3,094	0.00000000000000	2,708	0.00000000000000
3,181	0.00000000000000	2,764	0.00000000000000	3,093	0.00000000000000	2,707	0.00000000000000
3,181	0.00000000000000	2,764	0.00000000000000	3,088	0.00000000000000	2,707	0.00000000000000
3,181	0.00000000000000	2,763	0.00000000000000	3,084	0.00000000000000	2,706	0.00000000000000
3,179	0.00000000000000	2,761	0.00000000000000	3,084	0.00000000000000	2,704	0.00000000000000
3,177	0.00000000000000	2,761	0.00000000000000	3,083	0.00000000000000	2,704	0.00000000000000
3,177	0.00000000000000	2,761	0.00000000000000	3,083	0.00000000000000	2,704	0.00000000000000
3,176	0.00000000000000	2,760	0.00000000000000	3,078	0.00000000000000	2,702	0.00000000000000
3,174	0.00000000000000	2,757	0.00000000000000	3,077	0.00000000000000	2,700	0.00000000000000
3,173	0.00000000000000	2,756	0.00000000000000	3,076	0.00000000000000	2,699	0.00000000000000
3,171	0.00000000000000	2,756	0.00000000000000	3,075	0.00000000000000	2,699	0.00000000000000
3,169	0.00000000000000	2,754	0.00000000000000	3,075	0.00000000000000	2,699	0.00000000000000
3,169	0.00000000000000	2,752	0.00000000000000	3,075	0.00000000000000	2,697	0.00000000000000
3,169	0.00000000000000	2,751	0.00000000000000	3,074	0.00000000000000	2,695	0.00000000000000
3,166	0.00000000000000	2,751	0.00000000000000	3,074	0.00000000000000	2,694	0.00000000000000
3,165	0.00000000000000	2,749	0.00000000000000	3,074	0.00000000000000	2,693	0.00000000000000
3,164	0.00000000000000	2,748	0.00000000000000	3,072	0.00000000000000	2,693	0.00000000000000
3,163	0.00000000000000	2,748	0.00000000000000	3,069	0.00000000000000	2,692	0.00000000000000
3,163	0.00000000000000	2,748	0.00000000000000	3,068	0.00000000000000	2,689	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,160	0.00000000000000	2,746	0.00000000000000	3,068	0.00000000000000	2,688	0.00000000000000
3,158	0.00000000000000	2,745	0.00000000000000	3,068	0.00000000000000	2,688	0.00000000000000
3,156	0.00000000000000	2,745	0.00000000000000	3,067	0.00000000000000	2,687	0.00000000000000
3,155	0.00000000000000	2,743	0.00000000000000	3,066	0.00000000000000	2,685	0.00000000000000
3,154	0.00000000000000	2,743	0.00000000000000	3,065	0.00000000000000	2,685	0.00000000000000
3,152	0.00000000000000	2,742	0.00000000000000	3,064	0.00000000000000	2,684	0.00000000000000
3,151	0.00000000000000	2,741	0.00000000000000	3,063	0.00000000000000	2,682	0.00000000000000
3,151	0.00000000000000	2,741	0.00000000000000	3,062	0.00000000000000	2,682	0.00000000000000
3,149	0.00000000000000	2,740	0.00000000000000	3,061	0.00000000000000	2,681	0.00000000000000
3,148	0.00000000000000	2,737	0.00000000000000	3,058	0.00000000000000	2,680	0.00000000000000
3,148	0.00000000000000	2,737	0.00000000000000	3,058	0.00000000000000	2,679	0.00000000000000
3,148	0.00000000000000	2,733	0.00000000000000	3,058	0.00000000000000	2,678	0.00000000000000
3,147	0.00000000000000	2,732	0.00000000000000	3,057	0.00000000000000	2,678	0.00000000000000
3,144	0.00000000000000	2,732	0.00000000000000	3,053	0.00000000000000	2,676	0.00000000000000
3,144	0.00000000000000	2,730	0.00000000000000	3,053	0.00000000000000	2,675	0.00000000000000
3,143	0.00000000000000	2,729	0.00000000000000	3,053	0.00000000000000	2,675	0.00000000000000
3,143	0.00000000000000	2,729	0.00000000000000	3,050	0.00000000000000	2,674	0.00000000000000
3,138	0.00000000000000	2,728	0.00000000000000	3,047	0.00000000000000	2,674	0.00000000000000
3,138	0.00000000000000	2,727	0.00000000000000	3,047	0.00000000000000	2,672	0.00000000000000
3,138	0.00000000000000	2,727	0.00000000000000	3,046	0.00000000000000	2,671	0.00000000000000
3,137	0.00000000000000	2,727	0.00000000000000	3,045	0.00000000000000	2,669	0.00000000000000
3,136	0.00000000000000	2,727	0.00000000000000	3,041	0.00000000000000	2,669	0.00000000000000
3,129	0.00000000000000	2,726	0.00000000000000	3,041	0.00000000000000	2,668	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,127	0.00000000000000	2,726	0.00000000000000	3,039	0.00000000000000	2,666	0.00000000000000
3,124	0.00000000000000	2,724	0.00000000000000	3,039	0.00000000000000	2,665	0.00000000000000
3,124	0.00000000000000	2,723	0.00000000000000	3,039	0.00000000000000	2,665	0.00000000000000
3,122	0.00000000000000	2,720	0.00000000000000	3,039	0.00000000000000	2,663	0.00000000000000
3,122	0.00000000000000	2,720	0.00000000000000	3,036	0.00000000000000	2,662	0.00000000000000
3,121	0.00000000000000	2,718	0.00000000000000	3,034	0.00000000000000	2,662	0.00000000000000
3,119	0.00000000000000	2,717	0.00000000000000	3,031	0.00000000000000	2,661	0.00000000000000
3,118	0.00000000000000	2,716	0.00000000000000	3,026	0.00000000000000	2,658	0.00000000000000
3,116	0.00000000000000	2,716	0.00000000000000	3,026	0.00000000000000	2,657	0.00000000000000
3,104	0.00000000000000	2,715	0.00000000000000	3,025	0.00000000000000	2,657	0.00000000000000
3,102	0.00000000000000	2,715	0.00000000000000	3,022	0.00000000000000	2,656	0.00000000000000
3,098	0.00000000000000	2,714	0.00000000000000	3,018	0.00000000000000	2,654	0.00000000000000
3,097	0.00000000000000	2,714	0.00000000000000	3,018	0.00000000000000	2,651	0.00000000000000
3,096	0.00000000000000	2,713	0.00000000000000	3,016	0.00000000000000	2,651	0.00000000000000
3,096	0.00000000000000	2,712	0.00000000000000	3,016	0.00000000000000	2,651	0.00000000000000
3,095	0.00000000000000	2,712	0.00000000000000	3,015	0.00000000000000	2,651	0.00000000000000
3,093	0.00000000000000	2,710	0.00000000000000	3,010	0.00000000000000	2,650	0.00000000000000
3,089	0.00000000000000	2,710	0.00000000000000	3,010	0.00000000000000	2,648	0.00000000000000
3,088	0.00000000000000	2,710	0.00000000000000	3,009	0.00000000000000	2,647	0.00000000000000
3,087	0.00000000000000	2,710	0.00000000000000	3,008	0.00000000000000	2,646	0.00000000000000
3,086	0.00000000000000	2,709	0.00000000000000	3,008	0.00000000000000	2,646	0.00000000000000
3,086	0.00000000000000	2,706	0.00000000000000	3,008	0.00000000000000	2,646	0.00000000000000
3,086	0.00000000000000	2,706	0.00000000000000	3,005	0.00000000000000	2,646	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,084	0.00000000000000	2,700	0.00000000000000	3,005	0.00000000000000	2,645	0.00000000000000
3,082	0.00000000000000	2,700	0.00000000000000	3,001	0.00000000000000	2,644	0.00000000000000
3,081	0.00000000000000	2,699	0.00000000000000	3,001	0.00000000000000	2,638	0.00000000000000
3,080	0.00000000000000	2,699	0.00000000000000	3,000	0.00000000000000	2,638	0.00000000000000
3,080	0.00000000000000	2,699	0.00000000000000	3,000	0.00000000000000	2,636	0.00000000000000
3,077	0.00000000000000	2,698	0.00000000000000	2,999	0.00000000000000	2,636	0.00000000000000
3,076	0.00000000000000	2,697	0.00000000000000	2,999	0.00000000000000	2,636	0.00000000000000
3,075	0.00000000000000	2,696	0.00000000000000	2,998	0.00000000000000	2,634	0.00000000000000
3,074	0.00000000000000	2,696	0.00000000000000	2,996	0.00000000000000	2,634	0.00000000000000
3,074	0.00000000000000	2,695	0.00000000000000	2,993	0.00000000000000	2,633	0.00000000000000
3,073	0.00000000000000	2,695	0.00000000000000	2,993	0.00000000000000	2,633	0.00000000000000
3,070	0.00000000000000	2,694	0.00000000000000	2,993	0.00000000000000	2,632	0.00000000000000
3,069	0.00000000000000	2,693	0.00000000000000	2,992	0.00000000000000	2,631	0.00000000000000
3,066	0.00000000000000	2,693	0.00000000000000	2,991	0.00000000000000	2,629	0.00000000000000
3,066	0.00000000000000	2,693	0.00000000000000	2,990	0.00000000000000	2,628	0.00000000000000
3,065	0.00000000000000	2,693	0.00000000000000	2,987	0.00000000000000	2,625	0.00000000000000
3,064	0.00000000000000	2,691	0.00000000000000	2,986	0.00000000000000	2,623	0.00000000000000
3,061	0.00000000000000	2,690	0.00000000000000	2,986	0.00000000000000	2,622	0.00000000000000
3,060	0.00000000000000	2,690	0.00000000000000	2,984	0.00000000000000	2,621	0.00000000000000
3,059	0.00000000000000	2,688	0.00000000000000	2,982	0.00000000000000	2,620	0.00000000000000
3,058	0.00000000000000	2,687	0.00000000000000	2,982	0.00000000000000	2,618	0.00000000000000
3,057	0.00000000000000	2,687	0.00000000000000	2,979	0.00000000000000	2,617	0.00000000000000
3,050	0.00000000000000	2,686	0.00000000000000	2,977	0.00000000000000	2,616	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,049	0.00000000000000	2,684	0.00000000000000	2,977	0.00000000000000	2,614	0.00000000000000
3,048	0.00000000000000	2,684	0.00000000000000	2,976	0.00000000000000	2,612	0.00000000000000
3,046	0.00000000000000	2,679	0.00000000000000	2,975	0.00000000000000	2,612	0.00000000000000
3,046	0.00000000000000	2,678	0.00000000000000	2,974	0.00000000000000	2,612	0.00000000000000
3,045	0.00000000000000	2,677	0.00000000000000	2,973	0.00000000000000	2,612	0.00000000000000
3,045	0.00000000000000	2,676	0.00000000000000	2,968	0.00000000000000	2,609	0.00000000000000
3,042	0.00000000000000	2,676	0.00000000000000	2,968	0.00000000000000	2,608	0.00000000000000
3,041	0.00000000000000	2,676	0.00000000000000	2,965	0.00000000000000	2,607	0.00000000000000
3,040	0.00000000000000	2,675	0.00000000000000	2,964	0.00000000000000	2,607	0.00000000000000
3,039	0.00000000000000	2,674	0.00000000000000	2,962	0.00000000000000	2,606	0.00000000000000
3,038	0.00000000000000	2,674	0.00000000000000	2,962	0.00000000000000	2,606	0.00000000000000
3,037	0.00000000000000	2,672	0.00000000000000	2,958	0.00000000000000	2,605	0.00000000000000
3,035	0.00000000000000	2,669	0.00000000000000	2,957	0.00000000000000	2,605	0.00000000000000
3,035	0.00000000000000	2,668	0.00000000000000	2,955	0.00000000000000	2,604	0.00000000000000
3,034	0.00000000000000	2,667	0.00000000000000	2,954	0.00000000000000	2,603	0.00000000000000
3,033	0.00000000000000	2,665	0.00000000000000	2,953	0.00000000000000	2,601	0.00000000000000
3,033	0.00000000000000	2,665	0.00000000000000	2,946	0.00000000000000	2,598	0.00000000000000
3,030	0.00000000000000	2,662	0.00000000000000	2,946	0.00000000000000	2,598	0.00000000000000
3,025	0.00000000000000	2,662	0.00000000000000	2,945	0.00000000000000	2,597	0.00000000000000
3,025	0.00000000000000	2,662	0.00000000000000	2,944	0.00000000000000	2,597	0.00000000000000
3,024	0.00000000000000	2,662	0.00000000000000	2,944	0.00000000000000	2,595	0.00000000000000
3,019	0.00000000000000	2,662	0.00000000000000	2,944	0.00000000000000	2,595	0.00000000000000
3,018	0.00000000000000	2,662	0.00000000000000	2,944	0.00000000000000	2,594	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
3,016	0.00000000000000	2,660	0.00000000000000	2,943	0.00000000000000	2,594	0.00000000000000
3,015	0.00000000000000	2,660	0.00000000000000	2,943	0.00000000000000	2,593	0.00000000000000
3,013	0.00000000000000	2,658	0.00000000000000	2,937	0.00000000000000	2,593	0.00000000000000
3,012	0.00000000000000	2,656	0.00000000000000	2,936	0.00000000000000	2,592	0.00000000000000
3,011	0.00000000000000	2,655	0.00000000000000	2,936	0.00000000000000	2,591	0.00000000000000
3,010	0.00000000000000	2,652	0.00000000000000	2,935	0.00000000000000	2,591	0.00000000000000
3,009	0.00000000000000	2,652	0.00000000000000	2,934	0.00000000000000	2,590	0.00000000000000
3,007	0.00000000000000	2,652	0.00000000000000	2,932	0.00000000000000	2,589	0.00000000000000
3,006	0.00000000000000	2,651	0.00000000000000	2,931	0.00000000000000	2,582	0.00000000000000
3,006	0.00000000000000	2,650	0.00000000000000	2,931	0.00000000000000	2,580	0.00000000000000
3,005	0.00000000000000	2,650	0.00000000000000	2,930	0.00000000000000	2,578	0.00000000000000
3,002	0.00000000000000	2,649	0.00000000000000	2,929	0.00000000000000	2,578	0.00000000000000
3,001	0.00000000000000	2,648	0.00000000000000	2,927	0.00000000000000	2,576	0.00000000000000
2,999	0.00000000000000	2,646	0.00000000000000	2,926	0.00000000000000	2,576	0.00000000000000
2,999	0.00000000000000	2,645	0.00000000000000	2,922	0.00000000000000	2,576	0.00000000000000
2,997	0.00000000000000	2,638	0.00000000000000	2,922	0.00000000000000	2,576	0.00000000000000
2,997	0.00000000000000	2,636	0.00000000000000	2,917	0.00000000000000	2,571	0.00000000000000
2,995	0.00000000000000	2,635	0.00000000000000	2,913	0.00000000000000	2,570	0.00000000000000
2,994	0.00000000000000	2,634	0.00000000000000	2,912	0.00000000000000	2,568	0.00000000000000
2,993	0.00000000000000	2,631	0.00000000000000	2,911	0.00000000000000	2,564	0.00000000000000
2,991	0.00000000000000	2,630	0.00000000000000	2,910	0.00000000000000	2,563	0.00000000000000
2,989	0.00000000000000	2,629	0.00000000000000	2,909	0.00000000000000	2,563	0.00000000000000
2,986	0.00000000000000	2,629	0.00000000000000	2,908	0.00000000000000	2,563	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
2,985	0.00000000000000	2,629	0.00000000000000	2,906	0.00000000000000	2,562	0.00000000000000
2,985	0.00000000000000	2,627	0.00000000000000	2,906	0.00000000000000	2,556	0.00000000000000
2,983	0.00000000000000	2,626	0.00000000000000	2,906	0.00000000000000	2,554	0.00000000000000
2,977	0.00000000000000	2,626	0.00000000000000	2,905	0.00000000000000	2,552	0.00000000000000
2,974	0.00000000000000	2,625	0.00000000000000	2,905	0.00000000000000	2,550	0.00000000000000
2,973	0.00000000000000	2,623	0.00000000000000	2,896	0.00000000000000	2,549	0.00000000000000
2,969	0.00000000000000	2,623	0.00000000000000	2,896	0.00000000000000	2,549	0.00000000000000
2,965	0.00000000000000	2,619	0.00000000000000	2,895	0.00000000000000	2,549	0.00000000000000
2,964	0.00000000000000	2,618	0.00000000000000	2,894	0.00000000000000	2,548	0.00000000000000
2,964	0.00000000000000	2,618	0.00000000000000	2,893	0.00000000000000	2,547	0.00000000000000
2,963	0.00000000000000	2,618	0.00000000000000	2,891	0.00000000000000	2,545	0.00000000000000
2,962	0.00000000000000	2,615	0.00000000000000	2,889	0.00000000000000	2,539	0.00000000000000
2,957	0.00000000000000	2,614	0.00000000000000	2,887	0.00000000000000	2,539	0.00000000000000
2,954	0.00000000000000	2,612	0.00000000000000	2,883	0.00000000000000	2,538	0.00000000000000
2,952	0.00000000000000	2,611	0.00000000000000	2,878	0.00000000000000	2,537	0.00000000000000
2,948	0.00000000000000	2,609	0.00000000000000	2,877	0.00000000000000	2,536	0.00000000000000
2,947	0.00000000000000	2,609	0.00000000000000	2,877	0.00000000000000	2,536	0.00000000000000
2,944	0.00000000000000	2,609	0.00000000000000	2,874	0.00000000000000	2,536	0.00000000000000
2,943	0.00000000000000	2,608	0.00000000000000	2,872	0.00000000000000	2,534	0.00000000000000
2,943	0.00000000000000	2,608	0.00000000000000	2,869	0.00000000000000	2,533	0.00000000000000
2,940	0.00000000000000	2,608	0.00000000000000	2,867	0.00000000000000	2,533	0.00000000000000
2,940	0.00000000000000	2,606	0.00000000000000	2,865	0.00000000000000	2,533	0.00000000000000
2,936	0.00000000000000	2,605	0.00000000000000	2,862	0.00000000000000	2,532	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
2,935	0.00000000000000	2,604	0.00000000000000	2,859	0.00000000000000	2,531	0.00000000000000
2,934	0.00000000000000	2,602	0.00000000000000	2,858	0.00000000000000	2,528	0.00000000000000
2,934	0.00000000000000	2,601	0.00000000000000	2,857	0.00000000000000	2,526	0.00000000000000
2,931	0.00000000000000	2,601	0.00000000000000	2,854	0.00000000000000	2,525	0.00000000000000
2,931	0.00000000000000	2,600	0.00000000000000	2,854	0.00000000000000	2,522	0.00000000000000
2,926	0.00000000000000	2,598	0.00000000000000	2,851	0.00000000000000	2,520	0.00000000000000
2,923	0.00000000000000	2,597	0.00000000000000	2,849	0.00000000000000	2,517	0.00000000000000
2,923	0.00000000000000	2,596	0.00000000000000	2,849	0.00000000000000	2,516	0.00000000000000
2,922	0.00000000000000	2,592	0.00000000000000	2,848	0.00000000000000	2,516	0.00000000000000
2,917	0.00000000000000	2,590	0.00000000000000	2,848	0.00000000000000	2,515	0.00000000000000
2,917	0.00000000000000	2,588	0.00000000000000	2,847	0.00000000000000	2,511	0.00000000000000
2,916	0.00000000000000	2,586	0.00000000000000	2,846	0.00000000000000	2,511	0.00000000000000
2,915	0.00000000000000	2,586	0.00000000000000	2,845	0.00000000000000	2,509	0.00000000000000
2,914	0.00000000000000	2,585	0.00000000000000	2,843	0.00000000000000	2,508	0.00000000000000
2,913	0.00000000000000	2,582	0.00000000000000	2,843	0.00000000000000	2,508	0.00000000000000
2,911	0.00000000000000	2,581	0.00000000000000	2,842	0.00000000000000	2,507	0.00000000000000
2,911	0.00000000000000	2,580	0.00000000000000	2,840	0.00000000000000	2,506	0.00000000000000
2,909	0.00000000000000	2,580	0.00000000000000	2,840	0.00000000000000	2,506	0.00000000000000
2,901	0.00000000000000	2,579	0.00000000000000	2,838	0.00000000000000	2,505	0.00000000000000
2,901	0.00000000000000	2,579	0.00000000000000	2,837	0.00000000000000	2,505	0.00000000000000
2,900	0.00000000000000	2,579	0.00000000000000	2,831	0.00000000000000	2,501	0.00000000000000
2,900	0.00000000000000	2,578	0.00000000000000	2,827	0.00000000000000	2,498	0.00000000000000
2,896	0.00000000000000	2,578	0.00000000000000	2,825	0.00000000000000	2,497	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
2,895	0.00000000000000	2,575	0.00000000000000	2,824	0.00000000000000	2,496	0.00000000000000
2,894	0.00000000000000	2,575	0.00000000000000	2,824	0.00000000000000	2,496	0.00000000000000
2,891	0.00000000000000	2,571	0.00000000000000	2,820	0.00000000000000	2,495	0.00000000000000
2,890	0.00000000000000	2,564	0.00000000000000	2,817	0.00000000000000	2,495	0.00000000000000
2,890	0.00000000000000	2,561	0.00000000000000	2,816	0.00000000000000	2,492	0.00000000000000
2,886	0.00000000000000	2,559	0.00000000000000	2,816	0.00000000000000	2,491	0.00000000000000
2,882	0.00000000000000	2,557	0.00000000000000	2,815	0.00000000000000	2,486	0.00000000000000
2,881	0.00000000000000	2,556	0.00000000000000	2,814	0.00000000000000	2,482	0.00000000000000
2,880	0.00000000000000	2,555	0.00000000000000	2,812	0.00000000000000	2,482	0.00000000000000
2,876	0.00000000000000	2,554	0.00000000000000	2,809	0.00000000000000	2,481	0.00000000000000
2,869	0.00000000000000	2,551	0.00000000000000	2,805	0.00000000000000	2,480	0.00000000000000
2,868	0.00000000000000	2,550	0.00000000000000	2,800	0.00000000000000	2,479	0.00000000000000
2,862	0.00000000000000	2,550	0.00000000000000	2,800	0.00000000000000	2,475	0.00000000000000
2,857	0.00000000000000	2,549	0.00000000000000	2,800	0.00000000000000	2,472	0.00000000000000
2,854	0.00000000000000	2,548	0.00000000000000	2,800	0.00000000000000	2,470	0.00000000000000
2,853	0.00000000000000	2,547	0.00000000000000	2,800	0.00000000000000	2,469	0.00000000000000
2,853	0.00000000000000	2,545	0.00000000000000	2,791	0.00000000000000	2,467	0.00000000000000
2,850	0.00000000000000	2,542	0.00000000000000	2,790	0.00000000000000	2,465	0.00000000000000
2,843	0.00000000000000	2,540	0.00000000000000	2,790	0.00000000000000	2,463	0.00000000000000
2,843	0.00000000000000	2,540	0.00000000000000	2,781	0.00000000000000	2,462	0.00000000000000
2,838	0.00000000000000	2,539	0.00000000000000	2,780	0.00000000000000	2,461	0.00000000000000
2,836	0.00000000000000	2,539	0.00000000000000	2,778	0.00000000000000	2,460	0.00000000000000
2,834	0.00000000000000	2,537	0.00000000000000	2,778	0.00000000000000	2,459	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
2,834	0.00000000000000	2,537	0.00000000000000	2,776	0.00000000000000	2,458	0.00000000000000
2,831	0.00000000000000	2,537	0.00000000000000	2,773	0.00000000000000	2,456	0.00000000000000
2,831	0.00000000000000	2,535	0.00000000000000	2,772	0.00000000000000	2,454	0.00000000000000
2,826	0.00000000000000	2,533	0.00000000000000	2,767	0.00000000000000	2,454	0.00000000000000
2,820	0.00000000000000	2,532	0.00000000000000	2,766	0.00000000000000	2,453	0.00000000000000
2,819	0.00000000000000	2,529	0.00000000000000	2,763	0.00000000000000	2,451	0.00000000000000
2,817	0.00000000000000	2,525	0.00000000000000	2,760	0.00000000000000	2,451	0.00000000000000
2,813	0.00000000000000	2,524	0.00000000000000	2,758	0.00000000000000	2,450	0.00000000000000
2,809	0.00000000000000	2,522	0.00000000000000	2,756	0.00000000000000	2,438	0.00000000000000
2,809	0.00000000000000	2,521	0.00000000000000	2,756	0.00000000000000	2,437	0.00000000000000
2,805	0.00000000000000	2,520	0.00000000000000	2,754	0.00000000000000	2,435	0.00000000000000
2,799	0.00000000000000	2,517	0.00000000000000	2,753	0.00000000000000	2,434	0.00000000000000
2,796	0.00000000000000	2,516	0.00000000000000	2,753	0.00000000000000	2,432	0.00000000000000
2,796	0.00000000000000	2,514	0.00000000000000	2,749	0.00000000000000	2,429	0.00000000000000
2,777	0.00000000000000	2,513	0.00000000000000	2,749	0.00000000000000	2,427	0.00000000000000
2,774	0.00000000000000	2,513	0.00000000000000	2,745	0.00000000000000	2,426	0.00000000000000
2,772	0.00000000000000	2,512	0.00000000000000	2,742	0.00000000000000	2,424	0.00000000000000
2,771	0.00000000000000	2,510	0.00000000000000	2,742	0.00000000000000	2,423	0.00000000000000
2,756	0.00000000000000	2,509	0.00000000000000	2,739	0.00000000000000	2,423	0.00000000000000
2,755	0.00000000000000	2,505	0.00000000000000	2,737	0.00000000000000	2,418	0.00000000000000
2,755	0.00000000000000	2,503	0.00000000000000	2,733	0.00000000000000	2,415	0.00000000000000
2,748	0.00000000000000	2,502	0.00000000000000	2,731	0.00000000000000	2,414	0.00000000000000
2,748	0.00000000000000	2,500	0.00000000000000	2,725	0.00000000000000	2,414	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
2,747	0.00000000000000	2,498	0.00000000000000	2,723	0.00000000000000	2,413	0.00000000000000
2,739	0.00000000000000	2,495	0.00000000000000	2,722	0.00000000000000	2,411	0.00000000000000
2,730	0.00000000000000	2,493	0.00000000000000	2,721	0.00000000000000	2,410	0.00000000000000
2,723	0.00000000000000	2,487	0.00000000000000	2,721	0.00000000000000	2,409	0.00000000000000
2,717	0.00000000000000	2,484	0.00000000000000	2,717	0.00000000000000	2,398	0.00000000000000
2,713	0.00000000000000	2,478	0.00000000000000	2,717	0.00000000000000	2,396	0.00000000000000
2,711	0.00000000000000	2,478	0.00000000000000	2,711	0.00000000000000	2,396	0.00000000000000
2,705	0.00000000000000	2,471	0.00000000000000	2,707	0.00000000000000	2,396	0.00000000000000
2,701	0.00000000000000	2,470	0.00000000000000	2,707	0.00000000000000	2,390	0.00000000000000
2,698	0.00000000000000	2,470	0.00000000000000	2,706	0.00000000000000	2,390	0.00000000000000
2,685	0.00000000000000	2,468	0.00000000000000	2,695	0.00000000000000	2,388	0.00000000000000
2,676	0.00000000000000	2,467	0.00000000000000	2,693	0.00000000000000	2,387	0.00000000000000
2,676	0.00000000000000	2,467	0.00000000000000	2,691	0.00000000000000	2,385	0.00000000000000
2,670	0.00000000000000	2,463	0.00000000000000	2,691	0.00000000000000	2,375	0.00000000000000
2,667	0.00000000000000	2,462	0.00000000000000	2,684	0.00000000000000	2,369	0.00000000000000
2,659	0.00000000000000	2,462	0.00000000000000	2,683	0.00000000000000	2,365	0.00000000000000
2,656	0.00000000000000	2,461	0.00000000000000	2,675	0.00000000000000	2,364	0.00000000000000
2,648	0.00000000000000	2,460	0.00000000000000	2,674	0.00000000000000	2,363	0.00000000000000
2,645	0.00000000000000	2,455	0.00000000000000	2,673	0.00000000000000	2,361	0.00000000000000
2,640	0.00000000000000	2,453	0.00000000000000	2,671	0.00000000000000	2,357	0.00000000000000
2,637	0.00000000000000	2,453	0.00000000000000	2,671	0.00000000000000	2,354	0.00000000000000
2,621	0.00000000000000	2,452	0.00000000000000	2,669	0.00000000000000	2,350	0.00000000000000
2,613	0.00000000000000	2,452	0.00000000000000	2,667	0.00000000000000	2,348	0.00000000000000

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
2,610	0.00000000000000	2,451	0.00000000000000	2,666	0.00000000000000	2,345	0.00000000000000
2,607	0.00000000000000	2,449	0.00000000000000	2,649	0.00000000000000	2,343	0.00000000000000
2,606	0.00000000000000	2,445	0.00000000000000	2,646	0.00000000000000	2,331	0.00000000000000
2,601	0.00000000000000	2,445	0.00000000000000	2,644	0.00000000000000	2,327	0.00000000000000
2,589	0.00000000000000	2,445	0.00000000000000	2,643	0.00000000000000	2,326	0.00000000000000
2,582	0.00000000000000	2,438	0.00000000000000	2,642	0.00000000000000	2,323	0.00000000000000
2,579	0.00000000000000	2,437	0.00000000000000	2,642	0.00000000000000	2,307	0.00000000000000
2,563	0.00000000000000	2,437	0.00000000000000	2,642	0.00000000000000	2,300	0.00000000000000
2,557	0.00000000000000	2,434	0.00000000000000	2,636	0.00000000000000	2,299	0.00000000000000
2,541	0.00000000000000	2,431	0.00000000000000	2,636	0.00000000000000	2,298	0.00000000000000
2,539	0.00000000000000	2,429	0.00000000000000	2,635	0.00000000000000	2,296	0.00000000000000
2,538	0.00000000000000	2,429	0.00000000000000	2,635	0.00000000000000	2,290	0.00000000000000
2,528	0.00000000000000	2,428	0.00000000000000	2,634	0.00000000000000	2,286	0.00000000000000
2,523	0.00000000000000	2,427	0.00000000000000	2,634	0.00000000000000	2,279	0.00000000000000
2,512	0.00000000000000	2,424	0.00000000000000	2,629	0.00000000000000	2,271	0.00000000000000
2,500	0.00000000000000	2,422	0.00000000000000	2,625	0.00000000000000	2,271	0.00000000000000
2,465	0.00000000000000	2,420	0.00000000000000	2,624	0.00000000000000	2,271	0.00000000000000
2,463	0.00000000000000	2,418	0.00000000000000	2,621	0.00000000000000	2,264	0.00000000000000
2,456	0.00000000000000	2,417	0.00000000000000	2,612	0.00000000000000	2,256	0.00000000000000
2,455	0.00000000000000	2,417	0.00000000000000	2,610	0.00000000000000	2,255	0.00000000000000
2,452	0.00000000000000	2,416	0.00000000000000	2,607	0.00000000000000	2,249	0.00000000000000
2,415	0.00000000000000	2,414	0.00000000000000	2,603	0.00000000000000	2,227	0.00000000000000
		2,406	0.00000000000000	2,601	0.00000000000000		

Table 3 - System LOLP Table

Winter		Spring		Summer		Fall	
System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability	System Load Level (MW)	Loss of Load Probability
		2,405	0.00000000000000	2,590	0.00000000000000		
		2,403	0.00000000000000	2,585	0.00000000000000		
		2,394	0.00000000000000	2,585	0.00000000000000		
		2,393	0.00000000000000	2,578	0.00000000000000		
		2,386	0.00000000000000	2,578	0.00000000000000		
		2,385	0.00000000000000	2,573	0.00000000000000		
		2,383	0.00000000000000	2,561	0.00000000000000		
		2,379	0.00000000000000	2,552	0.00000000000000		
		2,374	0.00000000000000	2,549	0.00000000000000		
		2,373	0.00000000000000	2,539	0.00000000000000		
		2,371	0.00000000000000	2,530	0.00000000000000		
		2,367	0.00000000000000	2,529	0.00000000000000		
		2,364	0.00000000000000	2,527	0.00000000000000		
		2,327	0.00000000000000	2,521	0.00000000000000		
		2,322	0.00000000000000	2,517	0.00000000000000		
		2,319	0.00000000000000	2,509	0.00000000000000		
		2,300	0.00000000000000	2,509	0.00000000000000		
		2,297	0.00000000000000	2,477	0.00000000000000		
		2,295	0.00000000000000	2,444	0.00000000000000		
		2,293	0.00000000000000	2,425	0.00000000000000		
		2,290	0.00000000000000	2,409	0.00000000000000		
		2,288	0.00000000000000	2,391	0.00000000000000		
		2,283	0.00000000000000	2,388	0.00000000000000		

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 5

Responding Witness: David S. Sinclair

Q-5.   Reference the Company's confidential response to AG DR 1-139(a) as well as its
         overall LOLP analyses by hour. Provide a detailed explanation and all
         calculations supporting the assumed availability and outage rates for each
         generating unit.

A-5.   The Companies develop availability and outage rates as a two-step process. First,
         the Companies calculate an equivalent forced outage rate ("EFOR") and
         maintenance outage rate ("MOR") for each unit using annual historical
         Generating Availability Data Systems ("GADS") data over the previous ten
         years. The Companies look at trends in how these metrics are changing over
         time, and evaluate similar units as a group to reduce the impact of outliers in
         historical data. Trimble County 2 and Cane Run 7 are each modeled individually
         and have less historical data on which to create an availability forecast; therefore,
         the Companies focused on more recent data and removed outliers to develop
         those forecasts. The EFOR and MOR components are summed to create an
         equivalent unplanned outage rate ("EUOR") for each unit.

         Second, the EUOR is distributed across common availability states to account for
         unit derates based on further analysis of GADS data. For example, in the first
         step, Ghent 1 was assigned an EUOR of 7.4%. In the second step, historical
         analysis indicated that Ghent 1 is sometimes available at maximum capacity,
         sometimes not available at all, and sometimes partially available at levels
         between maximum capacity and zero. The Companies' process allocates the
         EUOR across these availability states to reflect varying levels of unit availability.
         In total, the prorated, or equivalent, unavailability of Ghent 1 is consistent with
         the EUOR of 7.4%. See attached for the calculations supporting the assumed
         availability and outage rates for each generating unit.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 6

Responding Witness: David S. Sinclair

Q-6.   Reference the Company's response to AG DR 1-140. Explain if the assumed level of 558 MW of Purchased Power is available each and every hour of the year and if it is treated as a supply resource identical to any other generation (power supply) resource.

A-6.   In the LOLP analysis, the 558 MW of potential purchased power was treated the same as other supply resources that can be called upon to avoid a loss of load and is assumed to be available every hour of the year. See also the response to PSC 3-23.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 7

Responding Witness: David S. Sinclair

Q-7.   Reference the Company's response to AG DR 1-140. Provide the forecasted
outage rates for each generating unit reflected in the Company's LOLP analysis.

A-7.   See the attachments in responses to Question No. 5 and AG 1-141(e).

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 8

Responding Witness: David S. Sinclair

Q-8.   Reference the Company's response to AG DR 1-141(e) Attachment 1. Provide:

a. an explanation of what columns C through I represent, note the narrative response indicates maximum capacity in the outage rate table varies by month but this table only includes seven columns; and,

b. an explanation and all calculations showing the availability for each unit during the forecasted test year.

A-8.
a. Columns C through I represent possible generation output levels and the corresponding probabilities for each generation unit's availability.   For example, Brown 1's generation output level will be 0 MW for 6.5% of the time, 74 MW for 3.3% of the time, and 107 MW for 84.8% of the time. Attachment 2 to AG 1-141(e) provides the varying maximum capacity levels that are applicable to the maximum generation output levels shown in Attachment 1.

b. See the response to Question No. 5.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 9

Responding Witness: William Steven Seelye

Q-9.   Explain if and how Mr. Seelye's class cost of service study ("CCOSS"), utilizing the LOLP methodology, grouped calculated hours into on-peak, off-peak, and shoulder periods.

A-9.   Weighted LOLP factors for fixed production costs were developed for each hour of the year. Fixed production costs were not grouped into on-peak, off-peak and shoulder periods. However, the information included in the Excel file used to develop the hourly LOLP factors could be used to perform such a grouping if desired.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 10

Responding Witness: William Steven Seelye

Q-10.   Explain if and how Mr. Seelye's CCOSS utilizing the LOLP methodology assigned specific generating unit costs to on-peak, off-peak, and shoulder periods based on individual generating unit operating costs.

A-10.   The LOLP methodology did not assign individual generating assets.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 11

Responding Witness: William Steven Seelye / David S. Sinclair

Q-11.   Reference the Company's response to AG DR 1-141(a) and its attachment. Explain what "Expected Unserved Energy (MWh)" represents and how (or if) it is specifically used within Mr. Seelye's development of production allocation factors within his LOLP CCOSS.

A-11.   Expected Unserved Energy (MWh) was provided for information only. It represents the amount of loss of load energy that is expected in each hour. It is not used for Mr. Seelye's development of production allocation factors.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 12

Responding Witness: David S. Sinclair

Q-12.   Reference the Company's response to AG DR 1-141(a) and its attachment. Explain and provide all calculations, tables, etc. showing the development of the following hour's "LOLP" and "Expected Unserved Energy (MWh)":

a. 8/28/19 at 1600 hours (annual system peak);

b. 1/7/20 at 800 hours (winter system peak);

c. 1/23/20 at 1100 hours; and,

d. 7/23/19 at 2100 hours.

A-12.
a. The Companies do not have access to PROSYM's calculation of LOLP and EUE, as it is a proprietary calculation that is performed internally in the software. PROSYM does not show the calculations and tables that lead to LOLP and EUE results.

b. See the response to part a.

c. See the response to part a.

d. See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 13

Responding Witness: William Steven Seelye / David S. Sinclair

Q-13.　Reference the Company's response to Staff 2-18 and responses to AG DR 1-139: the Company responded in Staff DR 2-18 that there are no differences between the LOLP methodology that was used to provide the LOLP CCOSS filed in 2016 compared to the methodology prepared in this proceeding; the Company responded in AG DR 1-139(b) that: hourly generation outputs are not produced by the LOLP analysis. However, in the 2016 case, the Company provided hourly generation outputs by unit in response to AG DR 1-292(b). In these regards, provide:

　　a.　an explanation and reconciliation of this apparent discrepancy; and,

　　b.　forecasted hourly generation output by unit for each hour of the forecasted test year, whether used or not used within the LOLP analysis.

A-13.

　　a.　There are no differences between the LOLP methodology that was used in 2016 and the methodology used in this proceeding. Hourly generation outputs are not produced as a result of the LOLP analysis. In the 2016 rate case, hourly generation outputs were provided from the Companies' business plan results, not from the LOLP analysis.

　　b.　See attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 14

Responding Witness: David S. Sinclair

Q-14.　　Reference the Companies' response to AG DR 1-16.

　　　　a.　Explain how the Companies calculate their target reserve margin.

A-14.

　　　　a.　See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

2018 IRP Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

September 2018

Table of Contents

1   Executive Summary

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. While the results of this analysis are generally communicated in the context of a summer peak reserve margin, the mathematics – like past reserve margin analyses – assess the Companies' ability to reliably serve customers in all hours.

Using the same methodology as the 2014 IRP, the 2018 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2021 over a wide range of summer peak reserve margins to identify the optimal generation mix for customers. With the Companies' existing resources, the forecasted summer peak reserve margin in 2021 is 23.5 percent in the base energy requirements forecast scenario. To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirement of their small-frame simple-cycle combustion turbines ("SCCTs"), the Demand Conservation Program ("DCP"), one or more Brown 11N2 SCCTs, and Brown 3.[1] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity to the generation portfolio.

The results of this analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2021. In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources. With the exception of the DCP, the reliability and generation production cost benefit for each of the Companies' marginal resources clearly exceeds the costs that would be saved by retiring these units. Consistent with the analysis supporting the Companies' December 2017 DSM filing, the DCP is only marginally favorable. However, given uncertainties moving forward related to load and environmental regulations, and considering physical reliability guidelines, the DCP should be continued at least in the near-term.

The target summer reserve margin range established in the 2014 IRP Reserve Margin analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. Based on the Companies' current load forecast and resources, the reserve margin required to meet this guideline is approximately 25 percent.[2] To determine the minimum of the target reserve margin range, the Companies estimated the increase in load that would result in the addition of generation resources. All

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[1] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11.

[2] The increase from 21 percent to 25 percent is driven primarily by an increase in the assumed variability of winter peak demands. The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015).

other things equal, if the Companies' load increases by 300 to 400 MW, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. With this load increase, the Companies' reserve margin would end up being 16 to 18 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

2   Introduction

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015).

Figure 1 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

Figure 1: Hourly Load Profiles, 2008-2017
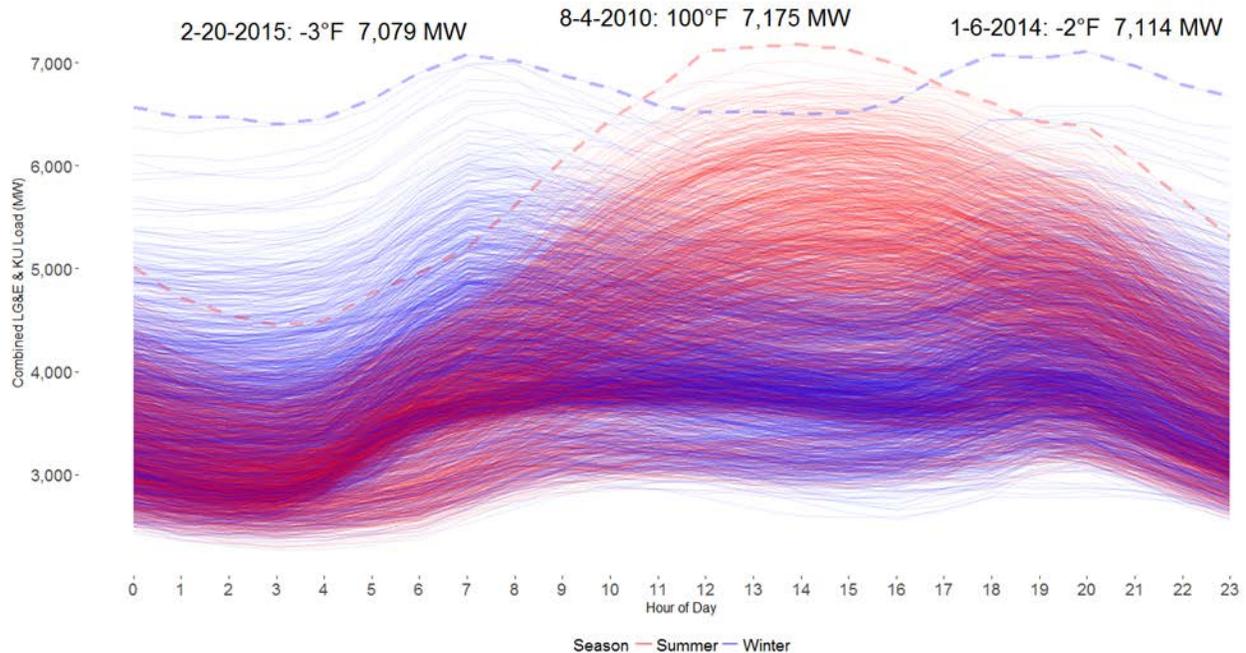
System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 2 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher. To serve customers in every moment, the Companies must have a portfolio of generation resources that can produce power when customers want it.

Figure 2: Four-Second Demands, 5:00-7:00 PM on January 6, 2014
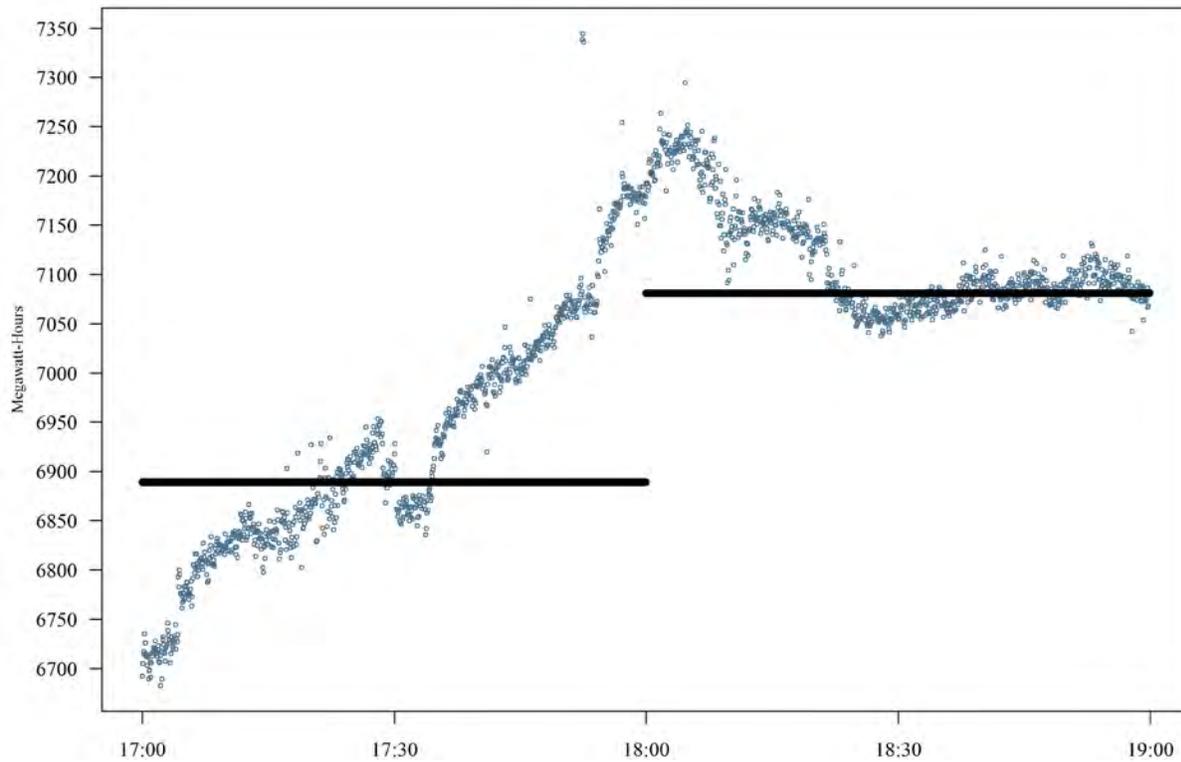
Table 1 contains the Companies' reserve margin forecast with planned retirements in the base energy requirements forecast scenario. Summer peak demand decreases from 2018 to 2019 primarily due to the departure of eight municipal customers. Load reductions associated with the Companies' DSM programs reflect changes to DSM programs approved in the Companies' recent DSM filing in Kentucky.[3] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. Beginning in 2021, the forecasted reserve margin for the base energy requirements scenario ranges from 23 percent to 24 percent.

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[3] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

Table 1: Peak Demand and Resource Summary (Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Summer Peak Demand	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Demand	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[4]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[5]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

Different types of generation resources play different roles in serving customers. The Companies' coal units have real-time load-following capabilities and can be brought on-line with less than a day's notice to serve load. With higher ramp rates and shorter start times, the Companies' natural gas combined-cycle ("NGCC") unit and large-frame SCCTs can respond to significant load swings and can be committed with little notice in response to forced outages. The Companies' small-frame SCCTs and demand-side resources have no load-following capabilities; while they can be committed in response to forced outages they require more notice than large-frame SCCTs or NGCC units and their small size and high cost limit their usefulness in dealing with forced outages. Finally, the Companies' renewable resources have little to no fuel or emissions costs, but they have no load-following capabilities and their availability during peak load conditions is uncertain due to their intermittent fuel source. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

[4] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.
[5] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

3   Analysis Framework

Figure 3 illustrates the costs and benefits of adding capacity to a generation portfolio.[6] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable) but fixed capacity costs increase. In their reserve margin analysis, the Companies' evaluate these costs and benefits over a range of reserve margins. The reserve margin at which the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

Figure 3: Costs and Benefits of Generation Capacity (Illustrative)
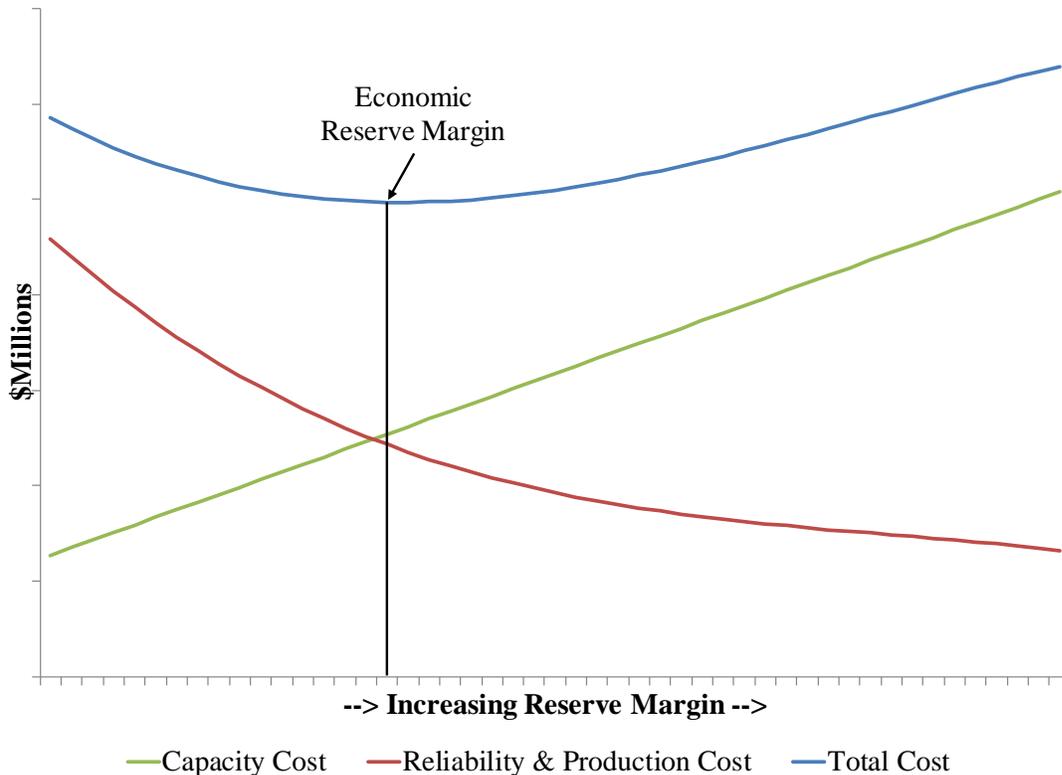
Figure 4 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity reduced to zero.[7]

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[6] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

[7] In Figure 4, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

Figure 4: Economic Reserve Margin and Capacity Cost (Illustrative)
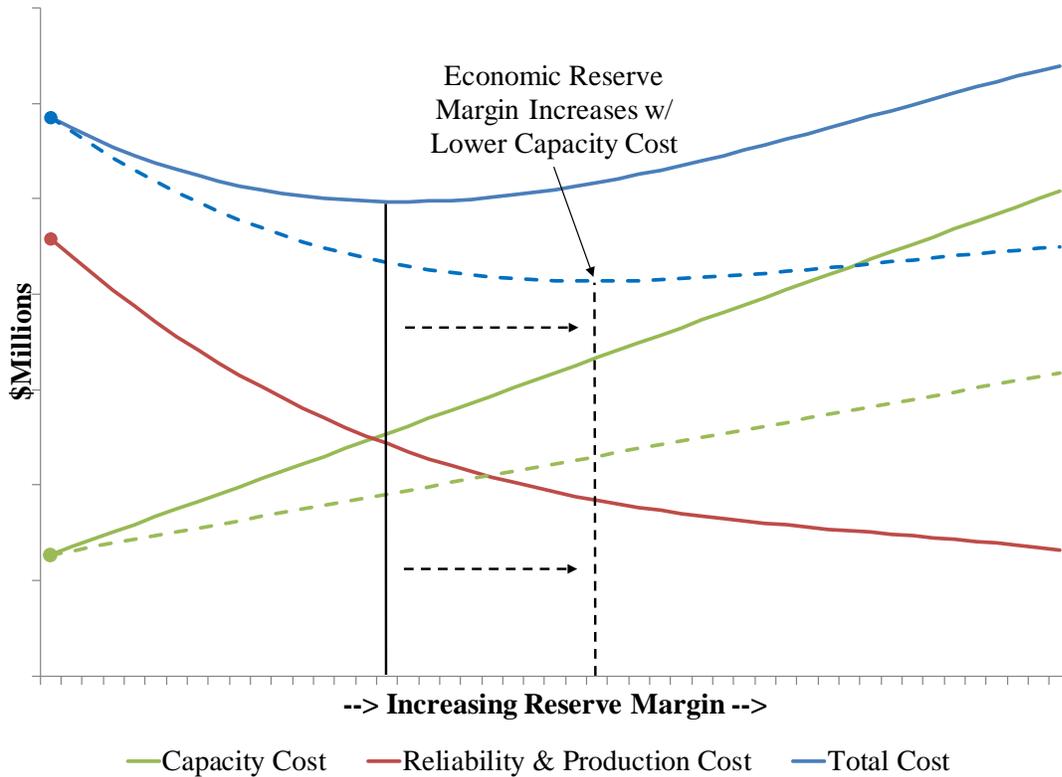
For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit as well as the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs.

The Companies evaluated reserve margins ranging from 12 to 24 percent in their 2014 IRP Reserve Margin Analysis. As this analysis was being developed, the Companies were evaluating the addition of Green River 5 (670 MW) at the Green River Generating Station. Without Green River 5, the Companies' reserve margin in 2018 was forecast to be 12 percent. Therefore, their reserve margin analysis evaluated only the costs and benefits of adding new capacity to their generation portfolio.

In the 2018 IRP base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. Therefore, to evaluate a similar range of reserve margins using the same methodology, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. The cost of continuing to operate each of the Companies' marginal resources is currently less than the cost of adding and operating new resources.

In North America, the most commonly used physical reliability guideline is the 1-in-10 LOLE guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, this analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to estimate reliability and generation production costs as well as the expected number of loss-of-load events in ten years ("LOLE") over a range of reserve margin levels. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve.[8] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011 and 2014 IRPs. SERVM models the availability of generating units in more detail than ELDCM but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4   Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1   Study Year

The study year for this analysis is 2021. The municipal departure, the end of the Bluegrass Agreement, and the retirements of Brown 1 and Brown 2 are planned to occur in 2019. Zorn 1 is assumed to retire on January 1, 2021. 2021 is the first full year after these events.

4.2   Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[9] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

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[8] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

[9] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.
- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of developing a target reserve margin range for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 17.1% (MISO[10]), 15.8% (PJM[11]), and 15% (TVA[10]).[12]

4.3   Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1   Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. Table 2 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

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[10] See NERC's "2018 Summer Reliability Assessment" at
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.
[11] See PJM's "2017 PJM Reserve Requirement Study" (October 12, 2017) at https://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx.
[12] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 2: 2021 LG&E/KU Generating Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW).[13]	EFOR
Brown 3	Coal	415	5.7%
Brown 5	SCCT	130	9.9%
Brown 6	SCCT	146	9.9%
Brown 7	SCCT	146	9.9%
Brown 8	SCCT	120	9.9%
Brown 9	SCCT	120	9.9%
Brown 10	SCCT	121	9.9%
Brown 11	SCCT	121	9.9%
Brown Solar	Solar	8	2.5%
Cane Run 7	NGCC	662	3.0%
Cane Run 11	Small-Frame SCCT	14	50.0%
Dix Dam 1-3	Hydro	32	N/A
Ghent 1	Coal	474	5.2%
Ghent 2	Coal	484	5.2%
Ghent 3	Coal	480	5.2%
Ghent 4	Coal	477	5.2%
Haefling 1-2	Small-Frame SCCT	24	50.0%
Mill Creek 1	Coal	299	5.2%
Mill Creek 2	Coal	296	5.2%
Mill Creek 3	Coal	390	5.2%
Mill Creek 4	Coal	476	5.2%
Ohio Falls 1-8	Hydro	64	N/A
OVEC-KU	Power Purchase	47	N/A
OVEC-LG&E	Power Purchase	105	N/A
Paddy's Run 11	Small-Frame SCCT	12	50.0%
Paddy's Run 12	Small-Frame SCCT	23	50.0%
Paddy's Run 13	SCCT	147	9.9%
Trimble County 1 (75%)	Coal	368	5.2%
Trimble County 2 (75%)	Coal	546	9.3%
Trimble County 5	SCCT	159	5.7%
Trimble County 6	SCCT	159	5.7%
Trimble County 7	SCCT	159	5.7%
Trimble County 8	SCCT	159	5.7%
Trimble County 9	SCCT	159	5.7%
Trimble County 10	SCCT	159	5.7%
CSR	Interruptible	141	N/A

4.3.2   Fuel Prices

The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 3 and Table 4. Fuel prices in neighboring regions were assumed to be consistent with the Companies'

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[13] Projected net ratings as of 2021. OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW. The ratings for Brown Solar, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 3: 2021 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	■
2	■
3	■
4	■
5	■
6	■
7	■
8	■
9	■
10	■
11	■
12	■

Table 4: 2021 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	■
Ghent	■
Mill Creek	■
Trimble County – High Sulfur	■
Trimble County – PRB	■

4.3.3   Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 5 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[14] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 141 MW.

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[14] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 5: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
▮▮	▮
▮	▮
▮▮▮	▮
▮	▮
▮	▮
▮	▮
▮▮▮	▮
▮	▮
▮▮▮	▮
▮▮▮	▮
▮▮▮▮	▮
▮	▮
▮▮	▮
▮▮	▮
▮▮	▮
▮	▮
▮▮▮	▮
▮▮	▮
Total	140.9

4.4   Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system as well as the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 6 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2016 and 2017 and the winter months of 2017 and 2018. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 45% of the time.

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[15] These customers have expressed interest in the CSR but have not yet begun service under this rider.

Table 6: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	95	45%
1 – 199	31	15%
200 - 399	5	2%
400 - 599	4	2%
600 - 799	10	5%
800 - 999	21	10%
>= 1,000	45	21%
Total	211	

During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis.

4.5   Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 7 summarizes the peak demand forecast for the Companies' service territories and neighboring regions in 2021. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 7: Peak Load Forecasts for 2021

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,350	19,302	36,121	29,811
Target Reserve Margin	N/A	17.1%	15.8%	15%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 45 hourly demand forecasts for 2021 based on actual weather in each of the last 45 years.

Table 8 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated.

Table 8: Summer and Winter Peak Demand Forecasts

LG&E/ KU Load	Summer					Winter				
	Weather Year	LG&E/KU	Coincident Peak Demand in Neighboring Regions			Weather Year	LG&E/KU	Coincident Peak Demand in Neighboring Regions		
			MISO-Indiana	PJM-West	TVA			MISO-Indiana	PJM-West	TVA
Max	1983	7,049	19,880	36,987	30,648	1985	7,336	16,322	38,359	33,450
75th %-ile	2017	6,490	18,933	33,786	30,024	1986	6,299	15,840	33,667	32,181
Median	2001	6,212	17,665	32,985	27,743	2010	5,901	16,049	32,913	31,003
25th %-ile	1996	6,070	17,610	33,631	27,472	1991	5,574	15,967	34,649	26,357
Min	1974	5,592	17,509	31,742	25,109	1990	5,085	14,886	34,004	25,936

Because the ability to purchase power from neighboring regions oftentimes depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions. Figure 5 plots the distributions of summer and winter peak demands in the Companies' service territories. The Companies' median peak demand is higher in the summer, but the variability in peak demands – as experienced over the past five years – is much higher in the winter.[16] This is largely due to the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

[16] The distributions in Table 8 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 141 MW in 2021. The maximum winter peak demand (7,336 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 5: LG&E and KU Peak Demands, 2021
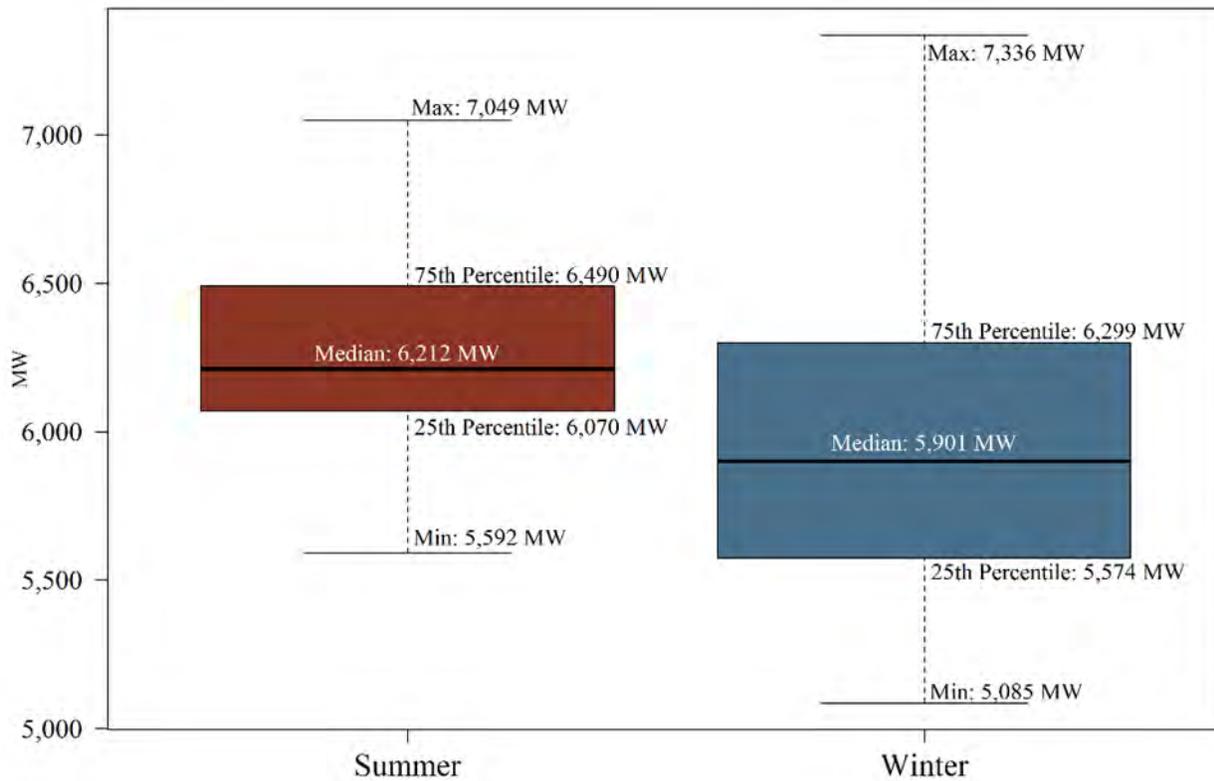
4.6 Marginal Resource Costs

In the base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. To evaluate reliability and cost at lower and higher reserve margins, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. Furthermore, because different types of resources have different operating capabilities, the Companies separately evaluated the retirement of marginal baseload and marginal peaking resources.

Table 9 contains stay-open costs (i.e., ongoing fixed operating and maintenance costs) and average energy costs for the Companies' baseload generation units that are 40 or more years old, the Companies' peaking units that are 15 or more years old, and the Companies' Demand Conservation Programs ("DCP").[17] The Companies' peaking units include large-frame and small-frame SCCTs; small-frame SCCTs include Haefling 1 and 2, Paddy's Run 11 and 12, and Cane Run 11. The stay-open costs in Table 9 are presented in 2021 dollars and are computed based on stay-open costs over an eight-year

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[17] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

maintenance cycle from 2020 to 2027.[18] Similar peaking units (e.g., Brown 5, 8, 9, 10, & 11) are grouped together. Average energy costs are computed based on the base fuel prices in Section 4.3.2.

Table 9: Marginal Resource Costs (2021 Dollars)

	Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Baseload	Brown 3	87.3	34	84
	Ghent 1	84.1	24	41
	Ghent 2	65.1	22	32
	Mill Creek 1	71.3	23	35
	Mill Creek 2	81.0	23	37
	Mill Creek 3	78.0	24	37
	OVEC	92.3	25	47
Peaking	Brown 5, 8, 9, 10, & 11	11.5	41	79
	Brown 6 & 7	20.5	31	66
	Paddy's Run 13	16.3	30	52
	Trimble County 5 & 6	29.7	30	64
	Small-Frame SCCTs	3.4	80	406
DSM	Demand Conservation Programs ("DCP")	25.6	145	460

To evaluate reserve margins less than 23.5 percent, the sum of stay-open and average energy costs in Table 9 was used to determine the order in which certain baseload and peaking resources would be considered for retirement. For example, based on these costs, the Companies assumed that the DCP would be retired first and the small-frame SCCTs would be retired second. The annual stay-open costs for these resources (expressed on a $/kW-year basis) are not as high as other resources, but the sums of stay-open and average energy costs (expressed on a $/MWh basis) are much higher due to their high dispatch cost which results in limited utilization. In addition, customer participation in the DCP is expected to decline moving forward and the small-frame SCCTs are far more likely to experience a catastrophic failure because of their age.[19] It would not be prudent to retire another unit with the assumption that these resources could be more heavily utilized.

Based on the sum of stay-open and average energy costs in Table 9, Brown 3 ("BR3") and OVEC are the Companies' marginal baseload units and, besides the small-frame SCCTs, Brown 5, 8, 9, 10, and 11 ("BR5, BR8, BR9, BR10, and BR11") are the Companies' marginal peaking units. The stay-open cost for Brown 3 is consistent with other baseload units but its average generation cost is higher primarily due to

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[18] An example of this calculation is included in Appendix A: Stay-Open Cost Example.

[19] The Companies do not plan for major maintenance on their small-frame SCCTs. These units range between 48 and 50 years old, have relatively inefficient heat rates compared to large-frame SCCTs, and are only operated on a limited basis.

the high cost of rail transportation for coal delivered to the Brown station. Despite this fact, the ability to shift generation to Brown 3 from other coal units is a valuable alternative for controlling fleet-wide emissions.[20]

To evaluate reserve margins greater than 23.5 percent, the analysis weighed the costs and benefits of adding new SCCT capacity. The cost of new SCCT capacity is taken from the 2018 IRP Resource Screening Analysis and is summarized in Table 10 in 2021 dollars. Not surprisingly, the carrying charge for new SCCT capacity ($123/kW-year) is higher than the stay-open costs for existing capacity ($3-92/kW-year) since their construction cost is considered sunk.

Table 10: SCCT Cost (2021 Dollars)[21]

Input Assumption	Value
Capital Cost ($/kW)	964.5
Fixed Charge Rate	9.0%
Fixed O&M ($/kW-yr)	13.3
Firm Gas Transport ($/kW-yr)	23.6
Carrying Charge ($/kW-yr)	123.3

4.7   Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[22] All studies split customers into residential, commercial, and industrial classes which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2021 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $18.30/kWh.

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[20] Brown 3 has been retrofitted with flue-gas desulfurization equipment designed to remove 98% of the unit's sulfur dioxide emissions, selective catalytic reduction designed to remove 90% of the unit's emissions of nitrogen oxides, a fabric filter baghouse designed to remove 99.5% of the unit's particulate matter, and an overall air quality control system designed to achieve 89% mercury removal.

[21] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[22] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;

"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;

"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;

"Value of Lost Load," University of Maryland, February 14, 2000.

Table 11 shows how the numbers were derived. The range for residential customers varied from $1.40/kWh to $3.50/kWh. The range for commercial customers varied from $24.70/kWh to $36.60/kWh while industrial customers varied from $12.80/kWh to $29.70/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $7.50/kWh.

Table 11: Cost of Unserved Energy (2021 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.60	1.40	3.50	3.00
Commercial	36%	36.60	33.30	24.70	25.70
Industrial	30%	21.10	29.70	12.80	25.70
System Cost of Unserved Energy		20.10	21.40	13.90	18.00
	Customer Class Mix	Min $/kWh	Mean $/kWh	Max $/kWh	Range $/kWh
Residential	34%	1.40	2.40	3.50	2.10
Commercial	36%	24.70	30.10	36.60	11.90
Industrial	30%	12.80	22.30	29.70	16.90
Average System Cost of Unserved Energy		18.30			

4.8   Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

4.9   Reserve Margin Accounting

The following formula is used to compute reserve margin:

Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast. While the Companies are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 6 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in

a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (251 MW) is approximately 3.5% of the forecasted summer peak demand in 2021 (6,350 MW). At reserve capacities less than 3.5% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($18,250/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 6: Scarcity Price Curve
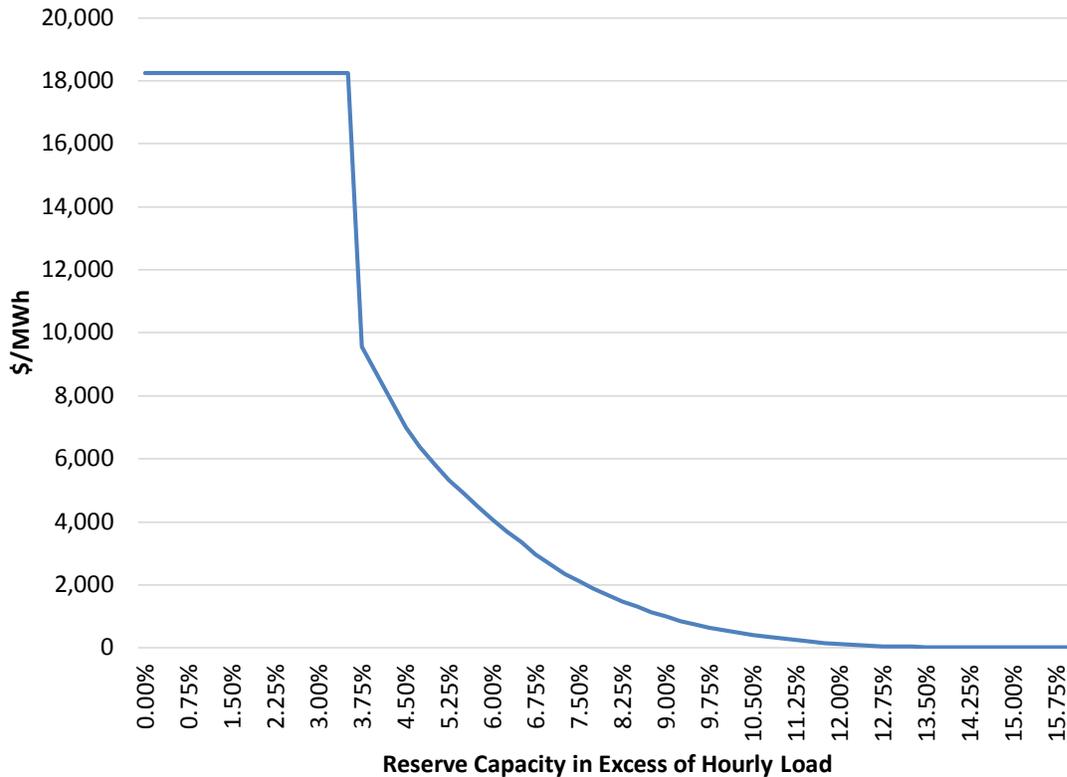
The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value and is approximately $55/MWh. Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities.

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of weather, load, and unit availability scenarios.

5   Analysis Results

5.1   Economic Reserve Margin and 1-in-10 LOLE Guideline

The Companies' forecasted reserve margin in 2021 is 23.5 percent in the base energy requirements forecast. Consistent with the methodology used in the 2014 IRP reserve margin analysis, the Companies estimated the sum of (a) annual capacity costs and (b) annual reliability and generation production costs

over reserve margins ranging from 13 percent to 26 percent to identify the optimal generation mix for customers. To evaluate operating at lower reserve margins with less reliability, the Companies evaluated the retirement of its existing baseload and peaking resources. To determine if adding resources would cost-effectively improve reliability, the Companies evaluated the addition of new SCCT capacity. The generation portfolios evaluated in this analysis are described in Table 12. As discussed previously, the DCP and small-frame SCCTs are always assumed to be retired before other resources.

Table 12: Generation Portfolios Considered in Reserve Margin Analysis

Generation Portfolio	Portfolio Abbreviation	Reserve Margin
Add 140 MW of SCCT capacity to Existing portfolio	Add SCCT2	25.7%
Add 70 MW of SCCT capacity to Existing portfolio	Add SCCT1	24.6%
Existing (includes retirements of Brown 1, Brown 2, and Zorn 1)	Existing	23.5%
Retire DCP	Ret DCP	21.7%
Retire DCP, small-frame SCCTs	Ret DCP_SF	20.6%
Retire DCP, small-frame SCCTs, Brown 8	Ret B8*	18.7%
Retire DCP, small-frame SCCTS, Brown 8-9	Ret B8-9*	16.9%
Retire DCP, small-frame SCCTS, Brown 8-10	Ret B8-10*	15.0%
Retire DCP, small-frame SCCTS, Brown 8-11	Ret B8-11*	13.1%
Retire DCP, small-frame SCCTS, Brown 3	Ret B3*	14.2%

*Portfolio also includes retirement of DCP and small-frame SCCTs.

LOLE as well as reliability and generation production costs were evaluated in SERVM and ELDCM for each generation portfolio in Table 12 over 45 weather year scenarios and hundreds of unit availability scenarios. Table 13 contains for each portfolio the average LOLE from ELDCM as well as the annual sum of (a) capacity costs and (b) reliability and generation production costs ("total cost"). The same results from SERVM are summarized in Table 14. Portfolios with LOLE greater than five (i.e., five times the 1-in-10 LOLE physical reliability guideline) are highlighted in gray. These portfolios are not considered viable based on their poor reliability. Capacity costs for each generation portfolio are presented as the difference between the portfolio's capacity cost and the capacity cost for the Ret B3* portfolio. Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85th and 90th percentiles ("%-ile") of the reliability and generation production cost distribution.

Table 13: Reserve Margin Analysis Results (ELDC Model, 2021 Dollars)

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
				[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	25.7%	0.9	55.7	765	781	790	821	837	846
Add SCCT1	24.6%	1.2	47.1	766	782	791	813	829	838
Existing	23.5%	1.6	38.5	767	783	793	805	821	831
Ret DCP	21.7%	1.7	36.1	767	783	793	803	819	829
Ret DCP_SF	20.6%	2.0	35.9	768	783	794	803	819	830
Ret B8*	18.7%	2.9	34.4	770	789	799	805	824	833
Ret B8-9*	16.9%	4.3	33.0	775	799	806	808	832	839
Ret B8-10*	15.0%	6.3	31.6	781	812	822	813	844	854
Ret B8-11*	13.1%	9.0	30.2	790	829	843	820	859	873
Ret B3*	14.2%	7.4	0.0	784	817	832	784	817	832

*Portfolio also include retirement of DCP and small-frame SCCTs.

Table 14: Reserve Margin Analysis Results (SERVM, 2021 Dollars)

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
				[B] Avg	[C] 85th %-ile	[D] 90th %-ile	[A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	25.7%	0.7	55.7	771	790	796	827	846	852
Add SCCT1	24.6%	1.0	47.1	771	793	797	818	840	844
Existing	23.5%	1.4	38.5	771	789	798	809	827	836
Ret DCP	21.7%	1.5	36.1	771	790	800	807	826	836
Ret DCP_SF	20.6%	1.8	35.9	772	792	801	808	828	837
Ret B8*	18.7%	2.6	34.4	773	796	805	807	831	839
Ret B8-9*	16.9%	3.8	33.0	775	808	814	808	841	847
Ret B8-10*	15.0%	5.8	31.6	780	815	819	812	847	850
Ret B8-11*	13.1%	8.5	30.2	788	833	844	819	863	874
Ret B3*	14.2%	8.3	0.0	791	837	843	791	837	843

*Portfolio also include retirement of DCP and small-frame SCCTs.

The results from ELDCM and SERVM are entirely consistent. The ranking of portfolios based on LOLE is the same in both models. Based on ELDCM, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is between 24.6 percent and 25.7 percent. Based on SERVM, this guideline is met with a 24.6 percent reserve margin. Considering the portfolios with LOLE less than five, when reliability and generation production costs are evaluated based on the average, 85th percentile, or 90th percentile of the distribution, the Existing and Ret DCP portfolios have the lowest total cost.

Beginning in 2019, the Companies will operate the Demand Conservation Programs in "maintenance" mode, allowing new participants to enroll in the program only to the extent existing devices are available to deploy. In addition, the Companies will reduce the annual incentive to $5 and pay participating customers only in years in which a Load Control Event is called. This analysis assumes customer participation will decline by almost 30 percent by 2021 as a result of these changes, but any actual change in customer participation is uncertain.

Additionally, the Companies face other uncertainties that impact resource planning decisions:

- Three of the Companies' coal units are not retrofitted with selective catalytic reduction ("SCR") so future changes to National Ambient Air Quality Standards may require one or more of the following actions in the next three to seven years: investment to further reduce emissions of nitrogen oxides ("NO_x"), changes in plant operations during ozone season, unit retirements, and acquisition of new generation.
- The U.S. Environmental Protection Agency ("EPA") recently proposed the Affordable Clean Energy Rule ("ACE Rule") which would establish guidelines for states to regulate carbon dioxide ("CO_2") emissions from existing fossil fuel-based electric generating units.[23] At a minimum, due to the regulatory timeline, fleet-specific and unit-specific planning for the ACE Rule is uncertain for the next two to four years.
- Lastly, as discussed in Section 5.(3) of Volume I, upside and downside uncertainty exists in the Companies' energy requirements forecast.

Given these uncertainties and the small differences in total costs between the Existing and Retire DCP portfolios, the Companies are not proposing to discontinue the DCP at this time. Instead, they will continue to the monitor participation in the DCP program and other regulatory and load developments to more holistically consider potentially broader changes to their generation mix in the future.

Consistent with the 2014 IRP reserve margin analysis, the Companies estimated total costs based on the 85th and 90th percentiles of the reliability and generation production cost distribution to consider the potential volatility in total costs for customers. For example, compared to the Existing portfolio and considering the results from both models, average annual reliability and generation production costs for the Ret B3* portfolio are $17 million to $20 million higher, but the Companies would expect these costs to be $39 million to $45 million higher once in ten years (90th percentile of distribution). With Brown 3 in the generation portfolio, the portfolio is far more reliable and reliability and generation production costs are significantly less volatile.

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[23] EPA is proposing to exempt SCCT and NGCC units from the ACE Rule, subject to public comments.

5.2   Target Reserve Margin Range

The target reserve margin range established in the 2014 IRP Reserve Margin Analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. Based on the Companies' current load forecast and resource mix, the reserve margin required to meet the 1-in-10 physical reliability guideline is approximately 25 percent (see Table 13 and Table 14). This increase is explained primarily by changes in the load forecast, which – consistent with recent history – assumes greater variability in winter peak demands (see Figure 5). The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015). The increased variability in winter peak demands is primarily the result of increasing penetrations of electric heating in the Companies' service territories.

For the minimum of the target reserve margin range, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause the Add SCCT1 portfolio to be less costly than the Existing portfolio. The reserve margin associated with this increase is the minimum of the reserve margin range. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads.[24] The results of this analysis from ELDCM and SERVM are summarized in Table 15 and Table 16, respectively. Consistent with the 2014 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. With no change in the load, total costs for the Existing and Add SCCT1 portfolios are the same as in Table 13 and Table 14. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

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[24] Not all industrial loads have high load factors. In practice, significant load changes would have to be evaluated on a case-by-case basis to ensure reliable supply.

Table 15: Minimum of Target Reserve Margin Range (ELDC Model)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	821	829	8	831	838	7
50	22.5%	833	841	8	844	851	7
100	21.6%	845	853	7	857	864	6
150	20.6%	859	865	6	871	876	6
200	19.7%	874	877	4	885	890	5
250	18.8%	890	892	2	899	903	4
300	17.9%	907	908	1	914	918	3
350	17.0%	925	925	(1)	931	933	2
400	16.2%	943	942	(1)	949	949	0

Table 16: Minimum of Target Reserve Margin Range (SERVM)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	827	840	13	836	844	8
50	22.5%	840	847	7	851	855	4
100	21.6%	852	863	11	864	869	4
150	20.6%	866	875	8	879	882	3
200	19.7%	883	886	4	896	897	1
250	18.8%	900	899	0	913	913	0
300	17.9%	914	918	4	925	930	6
350	17.0%	932	934	2	947	945	(3)
400	16.2%	955	950	(5)	964	963	(1)

5.3 Sensitivity Analysis

The inputs to the reserve margin analysis are detailed in Section 4. Because several of these inputs are uncertain, the Companies evaluated several sensitivities to the base case inputs. Table 17 lists the least-cost generation portfolios for each sensitivity, considering portfolios with LOLE less than five. As demonstrated in Section 5.1, the total cost of the Retire DCP portfolio is slightly lower than the total cost of the Existing portfolio in the base case scenario. The Companies used ELDCM to evaluate sensitivities to the cost of unserved energy, scarcity prices, EFOR, and ATC.

Table 17: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	85th Percentile	90th Percentile
Base Case	Ret DCP	Ret DCP
Cost of Unserved Energy		
25% Higher Cost of Unserved Energy ($22,800/MWh)	Ret DCP	Ret DCP
25% Lower Cost of Unserved Energy ($13,700/MWh)	Ret DCP	Ret DCP
Scarcity Prices		
25% Higher Scarcity Prices	Ret DCP	Ret DCP
25% Lower Scarcity Prices	Ret DCP	Ret DCP
Unit Availability		
Increase EFOR by 1.5 Points	Existing	Ret DCP
Decrease EFOR by 1.0 Points	Ret DCP	Ret DCP
Available Transmission Capacity		
No Access to Neighboring Markets	Ret DCP	Existing
High ATC (1,000 MW of ATC During Peak Hours)	Ret DCP	Ret DCP

5.4   Final Recommendation

All other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. Furthermore, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is approximately 25 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

6   Appendix A: Stay-Open Cost Example

Table 18 contains capital and fixed O&M expenses for Ghent 1 over a typical 8-year maintenance cycle. With the exception of 2021 when the unit is scheduled for a turbine overhaul, fixed O&M is fairly consistent; several components of fixed O&M are assumed to grow at constant escalation rates. Capital costs are also highest in 2021 and more consistent in other years.

Table 18: Ghent 1 Capital and Fixed O&M (Nominal $M)

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Capital	18.8	35.1	9.5	7.1	7.5	9.6	10.8	13.6
Fixed O&M	21.3	29.6	23.1	21.3	22.3	24.9	24.0	25.4

To compute a stay-open cost for each marginal unit in 2021 dollars, the Companies levelized each unit's capital and fixed O&M expenses over the unit's maintenance cycle and adjusted the levelized capital cost to reflect the cost's impact on annual revenue requirements. Then, they converted the levelized cost stream into an escalating stream over the same period such that the levelized and escalating streams have the same present value of revenue requirements. In the escalating stream, costs are assumed to escalate at two percent per year. Figure 8 plots the result of this process for Ghent 1. The levelized cost is $41.9 million. The escalating cost is $40.1 million in 2021 and increases from $39.3 million in 2020 to $45.2 million in 2027.

Figure 7: Ghent 1 Stay-Open Costs
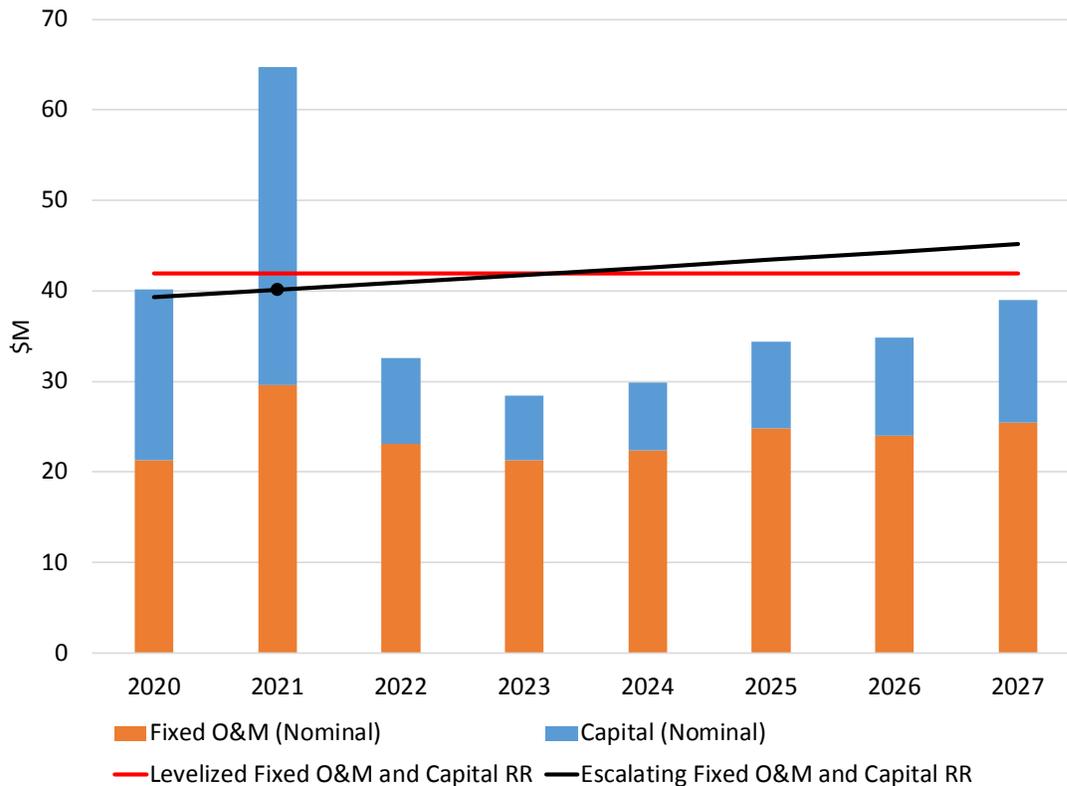
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 15

Responding Witness: David S. Sinclair

Q-15.   Reference the response to AG DR 1-147.

    a. In recent history, has the Cane Run unit 7 ordinarily had a lower dispatch order than Trimble County 2?

    b. Are there any particular reasons why through November of 2018, Cane Run unit 7 has a higher dispatch cost rate than Trimble 2?

    c. Provide the projected retirement dates for the Zorn 1 and Haefling CT units.

    d. Provide the expected retirement date for Brown units 1 and 2. Explain how the retirement of Brown units 1 and 2 will impact and affect the order of economic dispatch of the Companies' generating fleet.

    e. Explain whether the abundant rainfall in and around the Ohio Valley through 2018 has increased the dispatch rate for the Ohio Falls and Dix Dam hydro units.

    f. Has the dispatch rate for the Ohio Falls and Dix Dam units during 2018 YTD exceeded the average dispatch rate for these units over the past five (5) years?

A-15.

    a. Through November 2018, Cane Run 7 has had a lower dispatch order than TC2 in 7 of the 11 months in 2018.

    b. The primary determinant for the dispatch order of Cane Run 7 relative to Trimble 2 is the cost of natural gas. For November 2018, the expected average delivered price of natural gas was $3.00 per MMBtu, while earlier in the year the monthly expected average delivered price was as low as $2.66/MMBtu.

c. Zorn 1 is projected to retire by the end of 2021. The Haefling CT units do not have a projected retirement date. See the testimony of Mr. Sinclair at page 29, lines 4-8.

d. As indicated at page 11 of Mr. Bellar's Testimony, Brown units 1 and 2 are expected to retire at the end of February 2019. The retirement of these units is not expected to impact the relative economic dispatch order of the remaining units in the fleet.

e. The abundant rainfall in and around the Ohio Valley in 2018 has resulted in increased generation for Dix Dam, but reduced generation for Ohio Falls. The U.S. Army Corps of Engineers controls the Ohio River's flow to manage the navigable waterway. Operation of Ohio Falls generation requires water levels within a certain range, among other conditions.   The heavy rainfall experienced in the spring of 2018 resulted in conditions where the Ohio Falls units were often unable to be dispatched. Furthermore, high water levels often result in significant floating debris in the river, impeding opportunities to operate the hydro generation. The following chart shows the variability in 2018 of the generation produced by the Ohio Falls station.

2018 Ohio Falls Generation
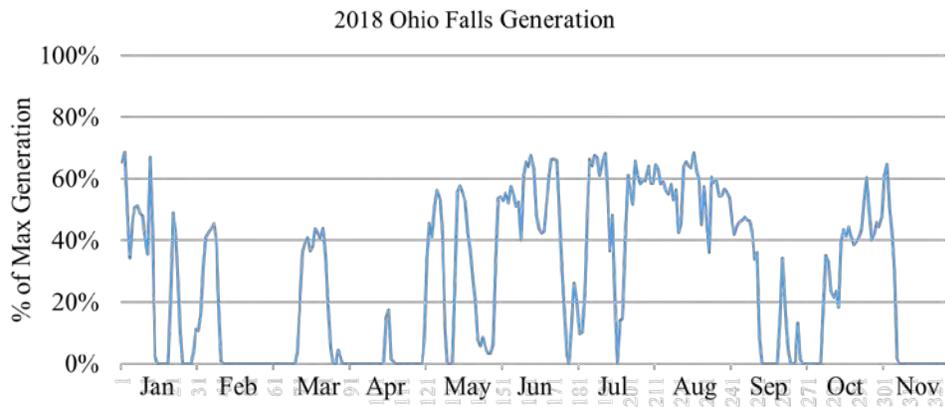
f. The 2018 YTD generation for Dix Dam is above the average for these units over the past 5 years, while the 2018 YTD generation for Ohio Falls is below the average for these units over the past 5 years.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 16

Responding Witness: Christopher M. Garrett

Q-16. Explain the purpose of an allowance for cash working capital in rate base.

A-16. The purpose of an allowance for cash working capital in rate base is to compensate investors for providing the funds necessary to meet the daily operational requirements of the utility. The cash working capital component of rate base represents the additional investor capital required to bridge the gap between when cash is paid for expenditures necessary to provide service and when cash is received from customers for that service.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 17

Responding Witness: Christopher M. Garrett

Q-17.   If the Companies are authorized to earn a return on their total capitalization, as opposed to rate base, explain why the addition of an allowance for cash working capital does not constitute double recovery.

A-17.   The allowance for cash working capital is a rate base component. Capitalization does not include the addition of an allowance for cash working capital component; therefore, there is no double recovery.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 18

Responding Witness: Christopher M. Garrett

Q-18.   Reference the Attachment in response to AG DR 1-58. Except for the ECR mechanism, explain why the Companies did not remove expenses recovered outside base rates (column D) from cash working capital.

A-18.   Cash working capital requirements associated with rate mechanisms other than the ECR mechanism are recovered through base rates consistent with previous base rate cases.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 19

Responding Witness: Daniel K. Arbough

Q-19.   Refer to the Companies' response to AG DR 1-63(a). Assuming no holidays and an ordinary work-week, if the Companies were to receive customer payments at the hours of 1:00, 12:00, 17:00, and 23:00 on a Monday, at what time would they have access to each of the customer payments on the following Tuesday?

A-19.   Per the conditions stated above, customer checks received by the Company on a Monday at 1:00 (Eastern Standard Time) approximately two-thirds would be available to the Company on Tuesday morning with the remaining 1/3 available Wednesday morning. Although the banks could not provide a specific time, the funds are typically available by 8:00. Customer checks received by the Company at 12:00, 17:00, and 23:00 would be available to the Company on Wednesday morning also around 8:00. Checks received that have an exception (e.g. illegible, inaccurate account number, missing account number etc.) would be delayed an additional day.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 20

Responding Witness: William Steven Seelye

Q-20.   Refer to Att_[Company]_PSC_1-65 [Company] Cash Working Capital 12ME Dec 2017 Final and the Companies' response to AG DR 1-63(b). Regarding the invoice sample used to develop the Other O&M expense lead, respond to the following items:

   a.   For each line item, indicate the method of cash disbursement (e.g., check, ACH, etc.).

   b.   For the top five invoices paid via check, provide the date of the check issuance and a copy of the check.

   c.   For the top five invoices paid via ACH, provide the date the ACH was initiated.

A-20.   It should be noted that the Company's population of Other O&M expenses was analyzed at a more granular level than invoice level in order to represent the various types of expenses (e.g., Safety Supplies, Third Party Labor, and Travel) incurred and their respective expense amount regardless of the total invoice amount, which could include various expense types, when billed to the Company by the vendor/supplier. Therefore, the responses to parts b and c below provide the top five Other O&M expense amounts (rather than invoice amounts) included in the Company's lead/lag day analysis.

   a.   See attachment being provided in Excel format.

   b.   See attached copies of checks for the following:

Rank	Item #	Vendor	Expense Amount	Date Issued	Check #	
1	195	GE INTERNATIONAL INC	$ 270,000.00	08/08/2017	432474	
2	161	GLOBAL GEAR AND MACHINE CO INC	$ 149,850.00	11/30/2017	437657	
3	119	ROSEN USA	$ 147,724.50	07/21/2017	431742	
4	127	S D MYERS INC	$ 136,254.00	01/30/2017	424444	
5	191	WHITEHEAD CONSTRUCTION INC	$ 109,583.14	04/25/2017	427890	(a)

(a)   Check amount includes payment for other expenses included on same invoice.

c.

Rank	Item #	Vendor	Expense Amount	Date Initiated
1	183	MECHANICAL DYNAMICS AND ANALYSIS LLC	$ 1,070,877.00	12/01/2017
2	185	MECHANICAL DYNAMICS AND ANALYSIS LLC	$ 848,708.75	12/20/2017
3	137	PRECISION SERVICES INC	$ 356,686.70	05/12/2017
4	168	RIVERSIDE GROUP LLC	$ 348,360.00	10/19/2017
5	68	NALCO COMPANY	$ 316,044.90	07/28/2017

The attachment is being provided in a separate file in Excel format.

Amount:	$270,000.00	Sequence Number:	7092311668
Account:	███████	Capture Date:	08/10/2017
Bank Number:	██████	Check Number:	432474

─ ▼ ─ **REMOVE DOCUMENT ALONG THIS PERFORATION** ─ ▼ ─

THIS DOCUMENT IS PRINTED IN TWO COLORS. DO NOT ACCEPT UNLESS BLUE AND GREEN ARE PRESENT.

LOUISVILLE GAS & ELECTRIC CO.

NO: 432474

P.O. Box 32030
Louisville, KY 40232

CHECK DATE
08-Aug-17

VOID 6 MONTHS
AFTER THIS DATE

BANK OF AMERICA, N.A.
Controlled Disbursement
Atlanta, Dekalb County, Georgia

64-1278
611 GA

PAY Two Hundred Seventy Thousand and 00/100 Dollars

CHECK AMOUNT
****$270,000.00

TO THE ORDER OF:

GE INTERNATIONAL INC
12505 COLLECTIONS CENTER
CHICAGO IL 60693-2505
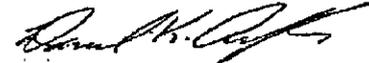
MANUAL COUNTER SIGNATURE REQUIRED OVER $300,000

Electronic Endorsements

Date	Sequence	Bank #	Endrs Type	TRN	RRC	Bank Name
08/10/2017	007092311668	111012822	Col Bank	N		BANK OF AMERICA NA
08/10/2017	000599001112419	111000025	Rtn Loc/BOFD	Y		BANK OF AMERICA NA

```
Amount:        $270,000.00        Sequence Number: 7092311668
Account:       ███████           Capture Date:    08/10/2017
Bank Number:   ████████          Check Number:    432474
```

>11000025<
CR PAYEE ACCT
LACK END GTD
BANK OF AMERICA

DO NOT WRITE STAMP OR ENDORSE BELOW THIS LINE

Electronic Endorsements

Date	Sequence	Bank #	Endrs Type	TRN	RRC	Bank Name
08/10/2017	007092311668	111012822	Col Bank	N		BANK OF AMERICA NA
08/10/2017	000599001112419	111000025	Rtn Loc/BOFD	Y		BANK OF AMERICA NA

Case No. 2018-00295
Attachment to Response to AG-2 Question No. 20b
Page 2 of 10
Seelye

```
Amount:      $149,850.00            Sequence Number: 4392771452
Account:     ▮▮▮▮▮▮▮▮▮              Capture Date:    12/05/2017
Bank Number: ▮▮▮▮▮▮▮               Check Number:    437657
```

LOUISVILLE GAS & ELECTRIC CO.

NO: 437657

P.O. Box 32030
Louisville, KY 40232

CHECK DATE	VOID 6 MONTHS
30-Nov-17	AFTER THIS DATE

BANK OF AMERICA, N.A.
Controlled Disbursement
Atlanta, Dekalb County , Georgia

64-1278
611 GA

PAY   One Hundred Forty-Nine Thousand Eight Hundred Fifty and
00/100 Dollars

CHECK AMOUNT
****$149,850.00

TO THE ORDER OF.

GLOBAL GEAR AND MACHINE CO INC
3725 CAROLINA ST
PADUCAH KY 42003

[signature]

MANUAL COUNTER SIGNATURE REQUIRED OVER $300,000

```
Electronic Endorsements
Date        Sequence          Bank #     Endrs Type    TRN   RRC   Bank Name
12/04/2017  654810001013430   83903328   Rtn Loc/BOFD  Y           COMMUNITY FINANCIAL
12/05/2017  594006182         61000146   Undetermined  N           FED RES BK OF ATLANT
12/05/2017  004392771452      11300016   Pay Bank      N
```

Case No. 2018-00295
Attachment to Response to AG-2 Question No. 20b
Page 3 of 10
Seelye

```
Amount:        $149,850.00          Sequence Number: 4392771452
Account:       ███████             Capture Date:    12/05/2017
Bank Number:   ███████             Check Number:    437657
```

Electronic Endorsements

Date	Sequence	Bank #	Endrs Type	TRN	RRC	Bank Name
12/04/2017	654810001013430	83903328	Rtn Loc/BOFD	Y		COMMUNITY FINANCIAL
12/05/2017	594006182	61000146	Undetermined	N		FED RES BK OF ATLANT
12/05/2017	004392771452	11300016	Pay Bank	N		

Amount:	$147,724.50	Sequence Number:	8152919142
Account:	▇▇▇▇▇	Capture Date:	08/02/2017
Bank Number:	▇▇▇▇▇	Check Number:	431742

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LOUISVILLE GAS & ELECTRIC CO.

NO: 431742

P.O. Box 32030
Louisville, KY 40232

CHECK DATE
21-Jul-17

VOID 6 MONTHS
AFTER THIS DATE

BANK OF AMERICA, N.A.
Controlled Disbursement
Atlanta, Dekalb County , Georgia

84-127B
611 GA

PAY One Hundred Forty-Seven Thousand Seven Hundred
Twenty-Four and 50/100 Dollars

CHECK AMOUNT
****$147,724.50

TO THE ORDER OF:
ROSEN USA
14120 INTERDRIVE EAST
HOUSTON TX 77032
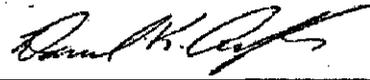
MANUAL COUNTER SIGNATURE REQUIRED OVER $300,000

Electronic Endorsements

Date	Sequence	Bank #	Endrs Type	TRN	RRC	Bank Name
08/02/2017	8152919142	111000025	Rtn Loc/BOFD	Y		BANK OF AMERICA NA

Amount: $147,724.50
Account: ▮▮▮▮▮▮▮
Bank Number: ▮▮▮▮▮▮

Sequence Number: 8152919142
Capture Date: 08/02/2017
Check Number: 431742

Seq: 18
Dep: 000340
Date: 08/02/17

For Deposit Only to
Honorable Inc
Oprona Inc Dba Rosen Usa Inc
Master,
Deposited by BofA

Electronic Endorsements
Date   Sequence   Bank #   Endrs Type   TRN   RRC   Bank Name
08/02/2017 8152919142   111000025   Rtn Loc/BOFD   Y   BANK OF AMERICA NA

THIS DOCUMENT IS PRINTED IN TWO COLORS. DO NOT ACCEPT UNLESS BLUE AND GREEN ARE PRESENT

LOUISVILLE GAS & ELECTRIC CO.

NO: 424444

P.O. Box 32030
Louisville, KY 40232

CHECK DATE	VOID 6 MONTHS
30-Jan-17	AFTER THIS DATE

BANK OF AMERICA, N.A.
Controlled Disbursement
Atlanta, Dekalb County , Georgia

84-1278
611 GA

PAY One Hundred Thirty-Six Thousand Two Hundred Fifty-Four
     and 00/100 Dollars

CHECK AMOUNT
****$136,254.00

TO THE ORDER OF

S D MYERS INC
180 SOUTH AVENUE
TALLMADGE OH 44278
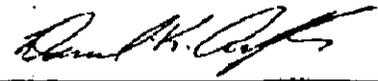
MANUAL COUNTER SIGNATURE REQUIRED OVER $300,000

Electronic Endorsements

Date	Sequence	Bank #	Endrs Type	TRN	RRC	Bank Name
02/06/2017	005092885729	11300016	Pay Bank	N		
02/03/2017	007400015685	31000053	Undetermined	N		PNC BK NA
02/03/2017	30019668	31000053	Rtn Loc/BOFD	Y		PNC BK NA

```
Amount:       $136,254.00          Sequence Number: 5092885729
Account:      3299027609           Capture Date:    02/06/2017
Bank Number:  06111278             Check Number:    424444
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Seq: 1

Dep: 000076

>031000053<

Date: 02/03/17

Location Code: 1

```
Electronic Endorsements
Date         Sequence         Bank #      Endrs Type    TRN    RRC    Bank Name
02/06/2017   005092885729     11300016    Pay Bank      N
02/03/2017   007400015685     31000053    Undetermined  N             PNC BK NA
02/03/2017   30019668         31000053    Rtn Loc/BOFD  Y             PNC BK NA
```

Case No. 2018-00295
Attachment to Response to AG-2 Question No. 20b
Page 8 of 10
Seelye

```
Amount:        $117,024.42          Sequence Number: 8792589724
Account:       ████████            Capture Date:    05/01/2017
Bank Number:   ████████            Check Number:    427890
```

LOUISVILLE GAS & ELECTRIC CO.

NO: 427890

P.O. Box 32030
Louisville, KY 40232

CHECK DATE	VOID 6 MONTHS
25-Apr-17	AFTER THIS DATE

BANK OF AMERICA, N.A.
Controlled Disbursement
Atlanta, Dekalb County, Georgia

64-1278
611 GA

PAY One Hundred Seventeen Thousand Twenty-Four and 42/100
     Dollars

CHECK AMOUNT
****$117,024.42

TO THE ORDER OF

WHITEHEAD CONSTRUCTION INC
PO BOX 92
ELIZABETHTON TN 37644-0092
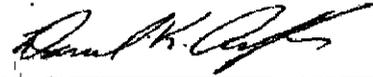
MANUAL COUNTER SIGNATURE REQUIRED OVER $300,000

```
Electronic Endorsements
Date        Sequence         Bank #      Endrs Type   TRN   RRC   Bank Name
05/01/2017  008792589724     11300016    Pay Bank     N
04/28/2017  000008904760229  84000026    Rtn Loc/BOFD  Y          FIRST TENNESSEE BK N
05/01/2017  000008154838932  91000019    Undetermined N           WELLS FARGO BK NA
```

```
Amount:        $117,024.42        Sequence Number: 8792589724
Account:       ▮▮▮▮▮▮▮▮           Capture Date:    05/01/2017
Bank Number:   ▮▮▮▮▮▮▮▮           Check Number:    427890
```

20170428900028340000100002

Electronic Endorsements

Date	Sequence	Bank #	Endrs Type	TRN	RRC	Bank Name
05/01/2017	008792589724	11300016	Pay Bank	N		
04/28/2017	000008904760229	84000026	Rtn Loc/BOFD	Y		FIRST TENNESSEE BK N
05/01/2017	000008154838932	91000019	Undetermined	N		WELLS FARGO BK NA

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Seelye

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 21

Responding Witness: Christopher M. Garrett / William Steven Seelye

Q-21.   Reference the Companies' response to AG DR 1-64(a). The response states, "The intention of including an expense lead of 0 for the referenced items as shown on Exhibit WSS-36 is to exclude these items from cash working capital."

   a.   Explain the theoretical basis for why the items with an expense lead of 0 (e.g., Pension, OPEB, Depreciation, and Amortization, etc.) are excluded from cash working capital.

   b.   Explain why the following component (provisions)/requirements should not be removed from the calculated allowance on Schedule B-5.2.

CASH WORKING CAPITAL COMPONENTS
FORECAST PERIOD FOR THE 12 MONTHS ENDED APRIL 30, 2020

	Expense (Lead)/Lag	Working Capital (Provided)/Required		
		KU	LG&E-E	LG&E-G
No-Notice Storage Injections and Withdrawals	-			(147,640)
Pension Expense	-	(214,820)	(95,286)	(37,570)
OPEB Expense	-	49,558	176,073	74,540
Depreciation and Amortization	-	41,549,335	26,415,000	4,805,169
Regulatory Debits	-	1,051,265	184,403	-
Amortization of Regulatory Assets	-	823,067	734,123	31,264
Amortization of Regulatory Liabilities	-	(393,968)	(36,934)	-
Deferred: Federal and State (Including ITC)	-	4,188,150	1,723,108	517,597
		47,052,586	29,100,488	5,243,359

Source: Schedules B-5.2

A-21.

   a.   The expense items referenced are intentionally excluded from the calculation of cash working capital from an expense standpoint because they do not have a current cash outlay when the expense is recorded.   The revenue requirements for these expense items included in revenue do however have a revenue lag due to the time it takes to recover the expenses from customers.

   b.   See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 22

Responding Witness: Christopher M. Garrett

Q-22.   Describe the items that comprise Materials & Supplies in Schedule B-5.1. As Materials & Supplies are deployed in operations, are they expensed or capitalized?

A-22.   The Materials and Supplies balance is comprised of physical inventory and undistributed stores expense accounts. Materials and supplies accounts contain inventory relevant to gas and electric transmission and distribution, substation and generation operations. Examples of the inventory covered in this account are wood poles, breakers, reclosers, wire and cable for transmission and distribution and motors, pumps, gearboxes, and valves to support generation. Stores expense undistributed accounts include the cost of supervision, labor and expenses incurred in the operation of general storerooms including purchasing, storage, handling and distribution of materials and supplies.

Items consumed from Material and Supplies inventory may be expensed or capitalized depending on the nature of the work being performed.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 23

Responding Witness: Christopher M. Garrett

Q-23.   Describe the items that comprise Prepayments in Schedule B-5.1. As Prepayments are spent in operations, are they expensed or capitalized?

A-23.   Prepayments are made up of agreements paid in advance of the Company receiving the related goods or services. Prepaid costs over $50,000 are recorded on the balance sheet at the time of payment and included as part of capitalization. With the exception of EPRI, the amortization of these prepaid costs over the life of the agreement are expensed to the appropriate FERC operating account. A small portion of the EPRI agreement related to engineering studies for Effluent Limitations Guidelines is capitalized.

Prepayments include maintenance contracts related to Information Technology systems, insurance contracts, industry membership dues such as EEI, EPRI and AGA, maintenance contracts for power plant control systems and other miscellaneous contracts meeting the policy thresholds.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 24

Responding Witness: Christopher M. Garrett

Q-24.   Reference the Companies' response to AG DR 1-50(a). The response states, "Yes, the Company recovers income taxes assessed on CIAC in base rates."

      a. What is the revenue requirement in connection with income taxes assessed on CIAC and Customer Advances?

      b. Where is the amount provided in response to subpart (a), above, reflected in the filing in this proceeding?

      c. Demonstrate and describe in detail how the revenue requirement for income taxes assessed on CIAC and Customer Advances is determined. For example, are the income taxes assessed simply flowed through operating income, or are they capitalized and reflected in rate base with corresponding depreciation in operating expense?

      d. If the income taxes assessed are capitalized and depreciated for ratemaking, provide the monthly balances reflected in rate base and monthly depreciation expense for the base period and the forecasted period.

A-24.

      a. The pro rata ADIT asset balance for CIAC and Customer Advances in the forecasted test year is estimated to be $21.9 million. $21.9 million times the grossed-up required rate of return of 9.45%, plus approximately $0.2 million of deficient (as opposed to excess) deferred tax expense results in a revenue requirement impact of $2.3 million.

      b. The pro rata ADIT asset balance is reflected in the ADIT balance per Section 16(8)(b) - Schedule B-6 in Tab 55 of the Filing Requirements. The deficient ADIT amounts are shown on Section 16(8)(b) - Schedule E-1 in Tab 58 of the Filing Requirements.

      c. See response to (a) on how the revenue requirement for income taxes assessed on CIAC and Customer Advances is determined. The accumulated deferred income tax (ADIT) resulting from CIAC and Customer Advances are

included with the other ADIT balances in the rate base calculation. Additionally, the KPSC issued a final order in Administration Case No. 313 - *The Effects of the Tax Reform Act of 1986 on Contributions in Aid of Construction and Customer Advances*, dated 8/1/1990, whereby the Commission disallows utilities from "grossing-up" CIAC and Customer Advances collected from customers.

d. Income taxes assessed on CIAC and Customer Advances are not capitalized and depreciated for ratemaking.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 25

Responding Witness: David S. Sinclair

Q-25.   Reference the Companies' response to AG DR 1-4.

a. Provide the Companies calculation for "Market Economy" prices for the Base and Test periods.

b. Given the Companies' response to subpart (c) to AG DR 1-4, explain under what circumstances purchasing energy from OVEC would be considered uneconomic, assuming the Inter-Company Power Agreement stays in place through 2040.

A-25.

a. In the response to AG 1-4(c), the Companies' calculation for market economy unit cost in the Base and Test periods included additional transmission and RTO cost components that did not allow for an appropriate comparison to historical costs for market economy energy only. The table below reflects the revised costs:

Market Economy	Purchase Cost ($)[1]	Purchase Volumes (MWh)	Unit Cost ($/MWh)
Base Period	24,089	782	30.82
Test Period	566,501	16,996	33.33

b. The Companies evaluate unit commitment, decommitment, and energy costs when determining whether any generator should be online. The decision to purchase energy from OVEC is no different. The Companies attempt to commit the most economic units at all times. Therefore, the Companies do not anticipate any circumstances in which it would purchase energy from OVEC that would be considered uneconomic when commitment and decommitment costs are properly considered.

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[1] These values differ from those provided in the KU's response to PSC 2-45(a) and LG&E's response to PSC 2-54(a) in that the values presented in AG 2-25(a) exclude automatic reserve sharing purchases, imbalance purchases, and SQF/LQF purchases, which are not considered to be market economy purchases.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 26

Responding Witness: David S. Sinclair

Q-26.   Reference the Companies' response to AG DR 1-4. Explain why Market Economy $/MWh has been significantly less than OVEC Energy Only for 2015–2017, but the Base Period and Test Period $/MWh for the Market Economy is significantly higher than OVEC Energy Only.

A-26.   In 2015-2017, the Companies were able to procure energy in certain hours at atypically low rates, in some instances at negative prices. Such low prices have occurred infrequently, and have skewed the weighted average prices due to a limited volume of higher cost purchases during those periods.

The Companies' market price forecast for the Base Period and Test Period is based on average historical hourly price volatility and therefore has a narrower distribution of hourly prices and does not include any negative prices. Also, forecasted purchases in the Base Period and Test Period contain a more balanced proportion of higher cost purchases relative to 2015-2017. The Companies participate in the hourly spot energy market every hour of the year and will continue to procure available hourly energy when it is economic relative to the Companies' generating resources.

The Market Economy $/MWh is not directly comparable to OVEC Energy Only, in that Market Economy reflects a limited subset of hours where market conditions warranted the Companies to make purchases on a non-firm basis. By definition, the Companies only make hourly market purchases when it is cheaper than their own marginal cost of generation. In contrast, the price of OVEC reflects an average price of all hours of the year, and the Companies maintain firm transmission rights to ensure the availability of its energy. A more appropriate comparison to OVEC Energy Only would be the average market prices. In the table below, these values have been appended to the table provided in the Companies' response to AG 1-4. The Market Economy Purchases for the Base and Test period have also been updated as noted in the Companies' response to Question No. 25(a).

$/MWh	OVEC Energy and Demand	OVEC Energy Only	Market Economy Purchases	Average Market Prices
2015	62.69	28.49	20.27	29.87
2016	55.77	26.91	12.62	27.11
2017	60.41	24.62	16.99	27.84
Base Period	62.59	23.78	30.82	32.02
Test Period	75.31	24.86	33.33	27.12

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 27

Responding Witness: Christopher M. Garrett / David S. Sinclair

Q-27.   Reference the response to AG DR 1-4. Confirm that in FERC docket ER18-459-004, OVEC filed proposed tariff revisions reflecting reduced federal corporate income tax in its stated transmission service rates.

   a.   Confirm that OVEC has requested an effective date of December 1, 2018 for these new rates.

   b.   State whether OVEC's new filing will reduce the rates OVEC charges to the Companies, and if so, provide the amount of the reduction, including any reduction in the revenue requirement. State also whether the reduction will be in energy charges, demand charges or both.

   c.   State whether OVEC is subject to state tax regulation in each of Indiana, Ohio and Kentucky. If so, state whether OVEC intends to pass on any state tax savings brought about as a result of the TCJA.

A-27.
   a.   The Companies can confirm from the publicly available filing that PJM and OVEC jointly requested that this filing be made effective as of December 1, 2018, coincident to OVEC's approved integration into the PJM markets.

   b.   Because OVEC deducts the revenues from the transmission charges from the OVEC demand charges for all OVEC facilities each month, the net effect to the Companies of any changes to OVEC's transmission rates is zero. See section 5.03(b) of the Inter-Company Power Agreement, which was provided as an attachment to the response to SC 1-1.

   c.   The Companies expect any tax savings to be minimal, if any, given OVEC's tax position. See the response to AG 1-5(h). As noted in OVEC's publicly available 2017 Annual Report, OVEC files income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. Note 7 to the financial statements describes OVEC's income taxes.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 28

Responding Witness: David S. Sinclair

Q-28.   Reference the Company's response to AG DR 1-5.

a.   Confirm that within the past few weeks, OVEC has officially been fully integrated into PJM. State whether this integration is expected to reduce any of OVEC's costs.

b.   With regard to the response to subpart (m), will the Companies agree to provide updates on OVEC's appeal to the U.S. Sixth Circuit Court of Appeals?

A-28.

a.   OVEC joined PJM on December 1, 2018. OVEC estimated a net initial financial benefit to OVEC of $1.9 million per year. This savings excludes approximately $0.4 million per year of PJM administrative charges that will be shared by OVEC sponsors and one-time charges in 2018 of $0.2 million.

b.   The Companies are not parties to those consolidated appeals that are pending before the U.S. Sixth Circuit Court of Appeals as case numbers 18-3787, 18-3788, 18-4095 and 18-4097 (collectively, the "Consolidated Appeals"). The pleadings filed in the Consolidated Appeals are publicly available and may be accessed by the Attorney General's Office through the Sixth Circuit's cm/ecf system with a valid PACER account. A link to the log in page for the Sixth Circuit's cm/ecf system follows: https://ecf.ca6.uscourts.gov/.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 29

Responding Witness: Robert M. Conroy

Q-29.   Reference the Companies' response to AG DR 1-9.

a. Confirm that the Commission's orders approving the settlement agreements
in Case Nos. 2008-00251 & 2008-00252 cited by the Companies only refer
to costs incurred and not ongoing costs related to the Companies' exit from
MISO.

b. Provide a specific citations to the portions of the Commission's orders
approving the settlement agreements in Case Nos. 2008-00251 & 2008-00252
cited by the Companies that discusses or evidences the Commission's consent
to ongoing transmission costs as a result of the Companies' exit from MISO.

c. The Company's response to subpart (e) to AG DR 1-9, that "the Companies
will address the effect on the revenue requirement" should FERC grant the
"request during the pendency of the proceeding" was not responsive. Explain
what effect on retail rates FERC's approval of the Companies' request will
have. The Company's response should include what adjustments to the test
period would be necessary and to what accounts those adjustments would be
made.

A-29.

a. Not confirmed. The Commission demonstrated its awareness of ongoing
transmission-related costs resulting from MISO exit in its May 31, 2006 final
order approving the Companies' withdrawal from MISO:

> The Dissenting Opinion also cites to the recent FERC decision
> imposing hold harmless conditions in conjunction with the
> LG&E and KU withdrawal from MISO. However, it is clear
> from that FERC opinion that the hold harmless conditions were
> imposed only in those circumstances where they had been
> expressly agreed to by LG&E and KU as part of their contractual
> agreement to join MISO. FERC actually rejected proposals that
> LG&E and KU should hold harmless future customers who are
> not currently served under an existing contract with a fixed rate,

stating that, "The TO [Transmission Owners] Agreement plainly states that the hold harmless provision applies only to *existing* service, not *future* service, and only for the remaining term of the contract for existing service." *Louisville Gas and Electric Company*, 114 FERC ¶ 61, 282, para. 49 (emphasis in original). In Kentucky, LG&E and KU have no contractual agreements to hold any retail customers harmless, and none of their customers are served under contracts with rates that are not subject to change by the Commission. In previously approving the request by Kentucky Power Company to join PJM, the Commission did not impose a hold harmless requirement in the event that the costs of membership in that RTO exceed the value of the benefits received.[2]

The dissent to which the majority was responding in that order was equally clear about understanding the nature of ongoing transmission-related costs resulting from MISO exit.[3]

The referenced orders in Case Nos. 2008-00251 and 2008-00252 addressed costs related to transmission service provided to East Kentucky Power Cooperative, Inc. ("EKPC") resulting from the same FERC hold-harmless (depancaking) requirement to which the Commission referred in its Case No. 2003-00266 final order.[4] The record of the 2008 proceedings was clear that the transmission-cost settlement agreement between the Companies and EKPC related to MISO exit and gave rise to the Companies' requested regulatory asset.[5] In short, it is clear the Commission understood in its February 2009 final orders in the Companies' 2008 rate cases that the Companies had incurred and were continuing to incur transmission-related costs resulting from MISO exit, which was fully consistent with the Commission's recognition of the issue when it approved MISO exit in 2006.

b. See the response to part a. above and the citations provided in response to AG 1-9.

c. The Company reiterates its response to AG 1-9(e), which is responsive to the question asked; the timing and substance of FERC's final order regarding the Companies' requested elimination of MMD charges will dictate whether the

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[2] Case No. 2003-00266, Order at 23-24 (May 31, 2006).

[3] *Id.* at 35-37.

[4] Case No. 2008-00251, Order at 8-9 and 11 (Feb. 5, 2009); Case No. 2008-00252, Order at 9 and 12 (Feb. 5, 2009).

[5] *See, e.g.*, Case No. 2008-00251, Application at 5-6 (July 29, 2008); Case No. 2008-00251, Testimony of Valerie L. Scott at 5-6 (July 29, 2008); Case No. 2008-00251, Testimony of Lonnie E. Bellar at 8-9 (July 29, 2008); Case No. 2008-00251, KU responses to PSC 2-109(c) and (f) (Sept. 11, 2008); Case No. 2008-00252, Application at 6 (July 29, 2008); Case No. 2008-00252, Testimony of Valerie L. Scott at 5-6 (July 29, 2008); Case No. 2008-00252, Testimony of Lonnie E. Bellar at 12 (July 29, 2008).

order will have any effect on the retail rates proposed in this proceeding. That aside, if FERC issued a final order granting all relief the Companies requested while the effect thereof could be accounted for in this proceeding, the effects would be an adjustment to decrease Account 566 Misc. Transmission Expenses by $8,977,509.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 30

Responding Witness: Daniel K. Arbough / Robert M. Conroy

Q-30.   Reference the direct testimony of Kent W. Blake, page 11, lines 1–2.

a. Provide the calculations that derived the projected revenue requirement increase of $8 million for KU and $5 million for LG&E due to the MMD.

b. What is the current status of the FERC proceeding?

A-30.
a. See attached.

b. LG&E and KU filed their application at FERC [under Sections 203 and 205 of the Federal Power Act to remove Merger Mitigation Depancaking] on August 3, 2018. Since then, numerous intervenors have filed protests of the FERC filing, to which the Companies filed answers. Subsequent replies and sur-replies have been and are continuing to be filed by the parties, which filings are allowed only if FERC grants leave. FERC is anticipated to issue an order on LG&E and KU's application on or before January 30, 2019. Such order could be a substantive determination of the issues, solely procedural (resulting in a deferral of a FERC decision or ordering settlement and hearing procedures), or some combination.

Depancaking cost per last rate case filing versus forecasted test period 4/30/20.

		TYE 6/30/18 **Total Company** **A**		**TYE 4/30/20** **Total Company** **B**	**Variance** **C = B - A**
LG&E Total Company					
KMPA - Depancaking		2,476,237		2,519,688	43,451
OMU - Depancaking		949,801		2,523,751	1,573,950
KYMEA - (departing Munis) Depancaking		396,561		3,934,070	3,537,509
Total Cost of Sales		3,822,599		8,977,509	5,154,910
KU Total Company		**Total Company**		**Total Company**	**Variance**
KMPA - Depancaking		4,806,818		4,679,426	(127,392)
OMU - Depancaking		1,843,729		4,686,963	2,843,234
KYMEA - Depancaking		769,793		7,306,134	6,536,341
Total Cost of Sales		7,420,340		16,672,523	9,252,183
KU KPSC	Juris %	KU KPSC	Juris %	KU KPSC	
KMPA - Depancaking	90.15%	4,333,579	90.58%	4,238,489	(95,091)
OMU - Depancaking		1,662,211		4,245,315	2,583,103
KYMEA - (departing Munis) Depancaking		694,006		6,617,683	5,923,678
Total Cost of Sales		6,689,796		15,101,486	8,411,690

Attachment to Response to AG-2 Question No. 30(a)
Page 1 of 1
Arbough

Depancaking cost per last rate case filing versus forecasted test period 4/30/20.

		TYE 6/30/18 **Total Company** **A**		**TYE 4/30/20** **Total Company** **B**	**Variance** **C = B - A**
LG&E Total Company					
KMPA - Depancaking		2,476,237		2,519,688	43,451
OMU - Depancaking		949,801		2,523,751	1,573,950
KYMEA - (departing Munis) Depancaking		396,561		3,934,070	3,537,509
Total Cost of Sales		3,822,599		8,977,509	5,154,910
KU Total Company		**Total Company**		**Total Company**	**Variance**
KMPA - Depancaking		4,806,818		4,679,426	(127,392)
OMU - Depancaking		1,843,729		4,686,963	2,843,234
KYMEA - Depancaking		769,793		7,306,134	6,536,341
Total Cost of Sales		7,420,340		16,672,523	9,252,183
KU KPSC	Juris %	KU KPSC	Juris %	KU KPSC	
KMPA - Depancaking	90.15%	4,333,579	90.58%	4,238,489	(95,091)
OMU - Depancaking		1,662,211		4,245,315	2,583,103
KYMEA - (departing Munis) Depancaking		694,006		6,617,683	5,923,678
Total Cost of Sales		6,689,796		15,101,486	8,411,690

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 31

Responding Witness: Robert M. Conroy / Christopher M. Garrett

Q-31.   Reference the Companies' response to AG DR 1-42.

    a. Are the Companies aware if the Kentucky Public Service Commission has ever approved outcomes resulting from the use of the Department of Energy's Interruption Cost Estimator as a basis for approving utility capital projects? If so, provide citation(s) to same.

    b. By using Capitalization as the basis for return instead of rate base, do the Companies earn a return on spare parts, as described in the previous request and response, that they otherwise would not if using rate base?

A-31.

    a. No.

    b. The Companies earn a return regardless of whether capitalization or rate base is used for valuation purposes for spare parts recorded to inventory or capital for accounting purposes. This is consistent with the methodology the Commission has relied upon in past cases to determine rate base.[6]

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[6] *See, e.g.*, *In the Matter of: Application of East Kentucky Power Cooperative, Inc. for Approval of an Environmental Compliance Plan and Authority to Implement an Environmental Surcharge*, Case No. 2004-00321, Order at 6 (Ky. PSC Mar. 17, 2005); *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend Its Environmental Surcharge Tariff*, Case No. 2000-00439, Order at Appendix B (Ky. PSC Apr. 18, 2001).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 32

Responding Witness: Lonnie E. Bellar

Q-32.   Reference the response to AG DR 1-197. For all capitalization projects identified in the response to AG DR 1-196, identify those projects in which the Companies elected to pursue options that were not the least-cost option, and the reason(s) supporting the Companies' election. Provide also a page number for each such project depicting where the project can be found in the 651-page response to AG DR 1-196.

A-32.   The companies evaluate projects thoroughly to determine the optimal solution from a safety, reliability, and an operational perspective. Projects are selected to mitigate the identified problem and risks at least reasonable cost. The following are projects in which the selected alternative had a higher cost than another but was selected as the lowest reasonable cost option that also acceptably mitigated the identified problem. The reason(s) supporting the Companies' election are described in the investment proposals submitted in response to AG DR 1-196. Projects for which the "do nothing" option is the only lower cost alternative to the one selected are not included as they do not solve the identified problem or have unacceptable risks or both.

Project	Page Number
Tyrone Controls	11
HARDIN CO SMITH 345KV P2	43
SR 2017 Earlington No-Nebo	146
Mill Creek 4533 Brk Rpl	231
PR Leitchfield 138kV Tap*	477

*There was an immaterial difference between the two least cost alternatives on this project. The recommended alternative involved replacing structures with steel instead of wood as steel is better over the long term for reliability and resilience to weather.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 33

Responding Witness: Daniel K. Arbough / Robert M. Conroy

Q-33.   Confirm that, based on a recent report in the publication Morningstar, from 2018-2022 PPL plans to invest in excess of $15 billion in infrastructure projects.

   a.   If so confirmed, how much of that investment will be made by LG&E-KU? Provide a description of the those projects, together with cost estimates.

   b.   Provide copies of any and all cost-benefit analyses not already of record pertaining to these projects.

   c.   State whether LG&E-KU intend to file applications for CPCNs regarding any such projects, and if so, provide an estimated date for the filing of all such applications.

A-33.

   a.   It is confirmed that in a recent PPL presentation noted that the capital plan for 2018-2022 reflected over $15 billion of spend which is based on the 2018 Business Plan. LG&E and KU expected to spend approximately $5 billion (LG&E $2.3 billion and KU $2.6 billion) which includes AMS and all mechanism spend. This projection is based on the 2018 Business Plan while this filing in this case is based on the 2019 Business Plan. See attached for a listing of projects with estimated costs.

   b.   See attached for the analysis completed for projects that 1) have spend in the future, 2) have been approved by the Investment Committee ("IC"), and 3) have not been provided previously in this proceeding. Projects with spend in excess of $2 million must be presented to the IC. The attachment does not include AMS or mechanism projects as these are not included in this proceeding. Many projects that are included in the $5 billion amount mentioned in a. above commence well into the future and are not far enough along to have been presented to the IC. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

   c.   See the response to PSC 2-58.

Project	Description	2018	2019	2020	2021	2022	Grand Total
123137	LG&E POLE INSPECTION	4,768,170	4,910,943	5,057,486	5,210,000	5,367,000	25,313,600
131681	NB Electric Dist LTP				32,444,000	32,444,000	64,888,000
131683	LGE Other Ele LTP				4,471,000	4,495,000	8,966,000
131721	N1DT LGE LTP CRESTWOOD SUB			2,499,599	1,500,000		3,999,599
138513	LGE LTP Maintain RR				19,304,000	19,872,000	39,176,000
138517	LGE Repair LTP				7,864,000	8,101,000	15,965,000
138521	LGE Misc LTP				485,000	494,000	979,000
141090	HW/SW - 004390 LGE 2015				306,000	312,000	618,000
141894	EDO BP AGING INFRA				3,104,000	2,977,000	6,081,000
146988	N1DT CW - 1225			335,370	1,164,000		1,499,370
148484	N-1 DIST XFMR PLAINVIEW CW	1,111,423	2,185,844				3,297,267
148490	N1DT PLAINVIEW SUB	2,987,529	1,940,532				4,928,061
148679	DSP GENE SUBSTATION 17-18		3,247,314	2,091,082			5,338,396
148680	DSP GENE SUB CKT WORK 17-18			716,420			716,420
148727	LGE SMAC 2017 PROJECT	1,198,337	1,408,250	1,697,236			4,303,823
148881	BACKYARD MACHINE-LEO	219,537		223,801			443,338
148882	DSP Tucker Station				5,488,000	2,880,000	8,368,000
148884	DIST XFMR LIME KILN CW		1,119,876	880,000			1,999,876
148885	DIST XFMR LIME KILN SUB		3,782,582	2,102,000			5,884,582
148886	N1DT MUD LN SMYRNA		450,000	1,000,000	550,000		2,000,000
148888	N1DT MUDLN/SMYRNA SUB		750,000	3,526,000	1,276,000		5,552,000
148896	LEO TRANSMISSION LINE CLR 2018	198,363					198,363
148897	DWNTWN NTWK VENT PRTCT REPL18	513,025					513,025
148898	LEO DWNTWN NTWK VAULT RPR 2018	1,230,536					1,230,536
148899	PILC 2018 LGE CABLE REPL	8,757,837					8,757,837
148909	SCM2018 LGE CAP&PIN INSLTR UPG	160,073					160,073
148910	SCM2018 LGE RPL SUB BATTERY	100,173					100,173
148911	SCM2018 LGE LEGACY RELAY REPL	84,201					84,201
148912	SCM2018 LGE RPL LGCYAIRMAG BRK	401,371					401,371
148913	SCM2018 LGE REPL LGCY OIL BRKR	301,074					301,074
148914	SCM2018 LGE REPL LEGACY RTU	155,983					155,983
148920	URD CABLE REPL/REJUV LGE 2018	2,162,002					2,162,002
148948	SCM2018 LGE LTC OIL FILT ADDS	57,817					57,817
148949	SCM2018 LGE MISC CAPITAL SUB	117,169					117,169
148950	SCM2018 LGE MISC NESC COMPL	54,137					54,137
148951	SCM2018 LGE OIL CONTAIN UPGRD	108,247					108,247
148952	SCM2018 LGE REPL XFMR FANS	210,346					210,346
148953	SCM2018 LGE REPL ABB VHK MECH	80,620					80,620
148954	SCM2018 LGE SUB BLDNG & GND	116,205					116,205
148955	SCM2018 LGE WILDLIFE PROTECT	80,855					80,855
148961	2018 LGE TRANSFORMER REWIND	1,109,087					1,109,087
148963	LEO TOOLS AND EQUIPMENT 2018	220,118					220,118
148968	SCM2018 LGE TOOLS & EQUIPMENT	32,404					32,404
148972	500 Gal Vactron	61,455					61,455
149063	LEO PADMOUNT SWITCHGEAR 2018	194,169					194,169
149682	N1DT Dixie Sub CW	333,401	1,067,969	98,380			1,499,750
151231	EDO Contingency	1,000	(1,000)	(3,000)			(3,000)
151481	DIST CAPACITORS LGE - 2019		149,742	154,350			304,092
151482	LEO TRANSMISSION LINE CLR 2019		203,420				203,420
151483	LEO PADMOUNT SWITCHGEAR 2019		198,689				198,689
151484	DWNTWN NTWK VENT PRTCT REPL19		925,997				925,997
151485	LEO DWNTWN NTWK VAULT RPR 2019		1,859,829				1,859,829
151486	PILC 2019 LGE CABLE REPL		12,950,806				12,950,806
151495	SCM2019 LGE CAP&PIN INSLTR UPG		163,925				163,925
151496	SCM2019 LGE RPL SUB BATTERY		103,037				103,037
151497	SCM2019 LGE LEGACY RELAY REPL		88,155				88,155
151498	SCM2019 LGE REPLLGCYAIRMAG BRK		408,979				408,979
151499	SCM2019 LGE REPL LGCY OIL BRKR		306,973				306,973
151500	SCM2019 LGE REPL LEGACY RTU		159,332				159,332
151529	SCM2019 LGE LTC OIL FILT ADDS		58,896				58,896
151530	SCM2019 LGE MISC CAPITAL SUB		121,872				121,872
151531	SCM2019 LGE MISC NESC COMPL		55,396				55,396
151532	SCM2019 LGE OIL CONTAIN UPGRD		110,617				110,617
151533	SCM2019 LGE REPL XFMR FANS		214,303				214,303
151534	SCM2019 LGE REPL ABB VHK MECH		81,454				81,454
151535	SCM2019 LGE SUB BLDNG & GND		118,775				118,775
151538	SCM2019 LGE WILDLIFE PROTECT		82,768				82,768
151544	2019 LGE TRANSFORMER REWIND		1,133,034				1,133,034
151546	LEO TOOLS AND EQUIPMENT 2019		223,803				223,803
151549	SCM2019 LGE TOOLS & EQUIPMENT		33,238				33,238
151553	URD CABLE REPL/REJUV LGE 2019		2,127,454				2,127,454
152331	DIST CAPACITORS LGE - 2018	148,262					148,262
152569	Repl Secondary Locators	35,197	39,885				75,082
152572	Manhole Structural Rep 2018	218,474					218,474
152573	Manhole Structural Rep 2019		422,880				422,880
152574	EZ Thump Fault Locators		128,519				128,519
152584	N1DT Dixie Substation	291,518	3,358,473	339,296			3,989,287
152585	N1DT STR Ashby Sub-CW		304,000	1,000,000	696,000		2,000,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
152586	N1DT Ashby Substation Project		750,000	2,750,000	500,000		4,000,000
152588	N1 Mud Ln/Smyrna Property		800,139				800,139
152957	N1DT P&G Clt 66 Bkr				360,000		360,000
153002	LGE CIFI RAP	2,000,130	1,750,000	1,250,000	1,250,000	1,281,000	7,531,130
153004	LGE CEMI	549,612	780,000	791,000	803,000	814,000	3,737,612
153006	REL System Hardening LGE	2,600,293	3,249,821	3,712,932	4,016,000	3,604,000	17,183,046
153015	Sub Exit Cable Repl LGE	1,077,573	1,102,366				2,179,939
153925	UPS CENTENNIAL HUB EXP	1,430,588					1,430,588
153926	UPS CENTENNIAL HUB EXP SUB	392,417					392,417
154095	IT Distrbution Automation LGE	1,227,240	294,000				1,521,240
155291	LEO TRANSMISSION LINE CLR 2020			208,393			208,393
155292	LEO PADMOUNT SWITCHGEAR 2020			203,356			203,356
155314	SCM2020 LGE TXFMR TOOLS	15,642	15,510	15,510			46,663
155315	LEO TOOLS AND EQUIPMENT 2020			238,756			238,756
155316	LGE HW/SW 2018	170,955	169,512	169,512			509,978
155320	DSP Ashbottom Sub		3,630,022	1,524,291			5,154,313
155338	PQ LOAD VOLT METERS		49,857				49,857
155340	Air Compressor-LEO		29,914				29,914
155344	2020 LGE TRANSFORMER REWIND			1,176,709			1,176,709
155352	Manhole Structural Rep 2020			428,877			428,877
155359	DWNTWN NTWK VAULT RPR 2020			1,885,316	1,924,000	857,000	4,666,316
155361	DWNTWN NTWK VENT PRTCT 2020			938,468	952,000	566,000	2,456,468
155363	PILC 2020 LGE CABLE REPL			12,653,636	12,865,000		25,518,636
155365	URD CABLE REPL/REJUV LGE 2020			2,157,463	2,189,000	719,000	5,065,463
155369	Sub Exit Cable LGE 2020			1,129,786	1,160,000	689,000	2,978,786
155375	N1 Hikes Lane Sub Property		1,200,766				1,200,766
155376	N1 Hikes Ln Sub - CW	193,572	1,350,721	452,522			1,996,815
155377	N1 Hikes Ln Sub	167,160	4,958,511	855,408			5,981,079
155381	DSP Ashbottom Distribution			499,487			499,487
155393	Purchase Garage Equip 2018BP	30,000	30,000	30,000			90,000
155685	Volt Var Optimization DMS LGE			430,000	430,000		860,000
156000	Distribution Auto LGE 2018	13,397,140					13,397,140
156002	Distribution Auto LGE 2019		14,280,005				14,280,005
156004	Distribution Auto LGE 2020			12,422,013	8,781,000	2,781,000	23,984,013
157000	SCM2020 LGE MISC NESC COMPL			56,504			56,504
157001	SCM2020 LGE REPL XFMR FANS			220,432			220,432
157002	SCM2020 LGE WILDLIFE PROTECT			84,884			84,884
157007	SCM2020 LGE TOOLS & EQUIPMENT			54,378			54,378
157026	SCM2020 LGE MISC CAPITAL SUB			124,088			124,088
157030	SCM2020 LGE RPL SUB BATTERY			104,490			104,490
157031	SCM2020 LGE LEGACY RELAY REPL			87,801			87,801
157032	SCM2020 LGE LEGACY AIR MAG BRK			419,190			419,190
157036	SCM2020 LGE REPL LGCY OIL BRKR			314,187			314,187
157037	SCM2020 LGE REPL LEGACY RTU			163,480			163,480
157038	SCM2020 LGE REPL ABB VHK MECH			83,854			83,854
157040	SCM2020 LGE OIL CONTAIN UPGRD			112,289			112,289
157041	SCM2020 LGE SUB BLDNG & GND			121,593			121,593
157051	SCM2020 LGE CAP&PIN INSUL UPGD			168,693			168,693
157060	SCM2020 LGE LTC OIL FILT ADDS			60,869			60,869
CCAPR340	Capital CAP/REG/RECL - 003400	326,042	335,845	345,451			1,007,337
CNBCD340O	NB Comm OH - 003400	3,194,536	3,350,860	3,518,905			10,064,301
CNBCD340U	NB Comm UG - 003400	5,389,271	5,648,063	5,929,129			16,966,463
CNBRD340O	NB Resid OH - 003400	1,873,441	1,964,430	2,063,733			5,901,603
CNBRD341U	NB Resid UG - 003410	5,498,243	5,759,810	6,051,865			17,309,918
CNBSV340O	NB Elect Serv OH - 003400	641,041	673,168	706,470			2,020,679
CNBSV340U	NB Elect Serv UG - 003400	1,926,787	2,023,406	2,122,749			6,072,942
CNBVLT343	NB Network Vaults - 003430	1,658,798	1,728,892	1,816,792			5,204,482
CPBWK340	El Public Works - 003400	1,651,866	1,696,969	1,748,921			5,097,755
CRCST340	Cust Requested - 003400	317,846	325,455	335,798			979,099
CRDCBL340	Repl Defective Cable - 003400	1,189,124	1,223,866	1,259,876			3,672,866
CRDD340O	Capital Rep Def OH - 003400	4,047,922	4,166,373	4,286,990			12,501,285
CRDD340U	Capital Rep Def UG - 003400	799,168	830,223	846,636			2,476,027
CRELD340	Capital Reliability - 003400	457,657	469,451	484,875			1,411,983
CRPOLE340	Pole Repair/Replace - 003400	4,603,316	4,731,718	4,871,667			14,206,700
CRSTLT332	Repair Street Lights - 003320	3,616,681	3,714,657	3,824,842			11,156,180
CSTLT332	NB Street Lights - 003320	2,189,738	2,294,160	2,405,672			6,889,570
CSTRMLGE	Cap LGE Major Storms	1,822,003	1,866,000	1,916,000	1,967,000	2,018,000	9,589,003
CSYSEN340	Sys Enh - 003400	1,000,654	1,027,902	1,058,950			3,087,506
CTBRD340O	Cap Trouble Orders OH - 003400	3,836,108	3,374,284	3,883,273			11,093,665
CTBRD340U	Cap Trouble Orders UG - 003400	1,455,587	1,978,119	1,527,332			4,961,039
CTPD340	Capital Thrd Party - 003400	899,577	925,741	953,252			2,778,570
CVLT343	Capital Network Vlts - 003430	1,295,565	1,331,200	1,372,022			3,998,786
CXFRM311	LGE Line Transformers	6,492,803	6,759,733	7,075,546			20,328,082
CXFRM340	NB Transformers - 003400	681,253	716,140	752,999			2,150,392
152583	STT Misc Project	50,000	50,000	50,000	75,000	75,000	300,000
138032	IMPROVE PIPELINES	500,268	500,268	500,268			1,500,804
139495	Gas Adjustments	2,000		(3,000)			(1,000)
141004	ST HELEN FACILITY	830,008					830,008
141880	GD BP NB				4,553,000	4,268,002	8,821,002

Project	Description	2018	2019	2020	2021	2022	Grand Total
141881	GDO BP ENHANCE				6,829,000	3,300,000	10,129,000
141883	GDO BP MAINTAIN				10,490,000	9,690,000	20,180,000
141884	GDO BP MISC				653,000	665,000	1,318,000
144857	MOIST REMOVAL UNIT	207,026	472,365				679,390
144869	PRESTON CITY GATE STAT	1,010,254	3,000,503				4,010,757
148081	WASTE MANAGEMENT GAS RELO	904,051					904,051
149155	UPGRADE ELEVATED PRESSURE	1,001,783					1,001,783
149157	SMALL TOOLS 2018 004060	53,509					53,509
149158	SMALL TOOLS 2018 004190	109,694					109,694
149160	REPL KUBOTAS TRAILERS 2018	292,710					292,710
149175	CONV DR DEEP TO UPPER 2018	258,150					258,150
149180	DRILL OBSV WELLS MULD 2018	488,382					488,382
149182	DRILL WELLS CENTER 2018	875,695					875,695
149183	DRILL WELLS MAG DEEP 2018	915,897					915,897
149185	DRILL WELLS MAG UPPER 2018	888,743					888,743
149192	MAG16 20" REPL ETOWN	208,790					208,790
149274	MULD INSULATION BLKTS 2018	20,224					20,224
149294	EXHAUST FANS SHALE COMP BLDG	74,508					74,508
149296	MULD STOR FLD VALVE REPL	50,724	49,562	49,756			150,042
149304	MAG STOR FLD BARRICADES	50,274					50,274
149305	MAG REPL PUR HEAT EXCHANGERS	458,183					458,183
149306	MAG REPL #1 REGENERATOR	289,090					289,090
149308	MAG STATION ESD UPGRADE	556,035					556,035
149311	MAG DEHY ABSORBER MANWAYS	52,156					52,156
149313	SECUR UPGRADES MAG & CANMER	50,073					50,073
149314	MAG VALVE ACTUATOR UPGR	602,741					602,741
149315	MAGNOLIA BACKUP DEHY	752,345					752,345
149318	STOR FLD TRUNKLINE MODIF	701,879					701,879
149335	MULD BLOW TRUCK F550 W TANK	91,538					91,538
149336	MULD TRACK SKID LOADER		89,942				89,942
149393	2018 H2S REMOVAL UNIT TOWER		2,184,736				2,184,736
149394	INST ADDTL FILTR IRON SULF REM	1,305,548					1,305,548
149397	MULD UPGR ESS SYSTEM	30,242	64,931				95,173
149400	VINE GROVE BACKUP FEED	83,023	544,772				627,795
149406	2018 RPL VLVS CG & DIST REG FC	99,597					99,597
149409	2018 PURCH ELEC RECORD GAUGES	170,751					170,751
149419	2018 UPG CT STA TRANSMITTERS	29,806					29,806
149422	SCADA HARDWARE RPLC	1,196,112					1,196,112
149434	SECURITY CG & LRG REG STA	50,139					50,139
152417	CONV DR DEEP TO UPPER 2019		311,867				311,867
152419	DRILL WELLS MAG DEEP 2019		973,331				973,331
152423	DRILL WELLS MAG UPPER 2019		949,557				949,557
152424	DRILL OBVS WELLS MULD 2019		514,739				514,739
152425	DRILL WELLS CENTER 2019		911,564				911,564
152433	IR DROP COUPON MON SYS 2019	32,996	475,717	475,717			984,431
152439	2019 RPL VLVS CG & DIST REG FC		99,034				99,034
152442	2019 PURCH ELEC RECORD GAUGES		169,230				169,230
152446	UPG CT STA TRANSMITTERS 2018		29,538				29,538
152449	SECURITY CG & LRG REG STA 2019		49,692				49,692
152454	MAG STOR FLD BARRICADES 2019		49,847				49,847
152455	COOLER HOUSING/SHROUDS 2019		95,598				95,598
152457	MULD INSULATION BLKTS 2019		20,224				20,224
152462	MULD REPL DEHY #1 REBOIL 2019		205,075	788,442			993,517
152464	MULD REDUN H2S FLAR STATN 2019		190,983	395,304			586,287
152466	LOU INTL AIRPORT	50,183					50,183
152475	SMALL TOOLS 2019 - 004190		111,989				111,989
152476	YARD COOLER AERIAL FAN REPL	824,216					824,216
152482	UPGRADE FT SYS DATA COMM 2017	120,665					120,665
152485	COELESCING FILTER SEP MAG	627,055					627,055
152495	MULD VALVE INDIC TRANSMITTER	47,866					47,866
152496	MUL STATN & FLD WASTE TANKS	54,579					54,579
152498	MULD HEAT TRACE IMPROVE 2018	20,224					20,224
152501	17 BP BOOSTER COMP PHASE 2	1,000,149	1,995,193	14,994,078			17,989,420
152503	ODORANT TANK LEVEL PROBES 2018	35,140					35,140
152505	MULD ENG & COMP UPGRADE		169,027				169,027
152506	RPL PRO IO MOD 2 ENG PNL 2019		30,123				30,123
152507	MUL STATN & FLD WASTE STORAGE		55,881				55,881
152508	COMPRESSOR ENGINE AUTO EQUIP		486,029				486,029
152511	SHALE BLDGS SECURITY UPGRADE	40,447					40,447
152513	CANNONS LN REGU STATN 2018	300,161	1,995,754	1,000,102			3,296,017
152514	ODORANT DETECTION SYSTEM	105,702					105,702
152517	PAVE LG&E ROAD	225,653	199,043				424,696
152522	CITY GATE STATION LAGRANGE		300,161	1,995,910			2,296,071
152524	ODORANT TANK LEVEL PROBES		34,853				34,853
152525	REPL HEAT EXCHANGER		258,922				258,922
152526	WATER STORAGE TANKS		902,079				902,079
152527	HOWARD LANE REDUNDANT FEED	81,988					81,988
152528	INGERSOLL EXHAUST HEADERS		69,274				69,274
152529	H2S GAS DETECTION		54,970				54,970

Project	Description	2018	2019	2020	2021	2022	Grand Total
152530	#2 BOILER REPLACEMENT		997,625				997,625
152531	ENGINE ROOM TRANSITE SIDING		519,063				519,063
152532	CONTROL RM W BASEMENT		492,278				492,278
152534	ONLINE AMINE ANALYZER		54,970				54,970
152535	ENGINE ROOM OVERHANG		160,436				160,436
152536	ENGINE VIBRATION EQUIP		199,908				199,908
152541	RIVER RD WIDENING - RELOCATION		1,249,902	1,249,764	500,000		2,999,665
152543	RIVER RD MEDIUM PRESSURE		500,040	501,007			1,001,047
152544	BALLARDSVILLE REINFORCEMENT	500,487					500,487
152546	EAST END REINFORCEMENT	5,147,579					5,147,579
152549	ETOWN GAS SYS REINFORCEMENT		439,980				439,980
152551	DUMP TRUCK 2019		84,879				84,879
152553	SMALL TOOLS 2019 004060		54,099				54,099
152561	REPLACE PAD METERS				2,696,000	1,750,000	4,446,000
153662	BULLITT CO SYSTEM REINFORCE	14,931,426	15,000,726				29,932,152
155389	Muld - H2S scavenging towers				5,227,000		5,227,000
406000001	Mt Washington MP Reinforcement	676,006					676,006
406000002	Small Tools 2020 004060			73,484			73,484
406000003	REPLACE PAD METERS 2018	1,995,709					1,995,709
406000004	REPLACE PAD METERS 2019		2,032,081				2,032,081
406000005	REPLACE PAD METERS 2020			2,140,383			2,140,383
406000007	REPLACE STEEL SVCS 2019		9,699,704				9,699,704
406000009	REPLACE STEEL SVC 2020			9,994,686			9,994,686
406000010	REG FAC RET ZHALE SMITH-HWY 53	129,660					129,660
406000011	REG FAC RET ELDER PARK	99,423					99,423
406000012	REG FAC RET COVERED BRIDGE	85,852					85,852
406000013	REG FAC RET HWY 42-HUNTERS RDG		116,155				116,155
406000014	REG FAC RET RIVER RD-JUNIPER B		84,155				84,155
406000015	REG FAC RET HWY 44-HARRIS DR		77,769				77,769
406000016	REG FAC RET HWY 44-BETHEL CH			130,525			130,525
406000017	REG FAC RET WATERGATE-HALLS			182,148			182,148
406000018	REG FAC RET 6TH-HILL			20,523			20,523
406000019	NB AIKEN RD GAS MAIN	266,145					266,145
406000021	UPGRADE ELEVATED PRESSURE 19		1,997,686				1,997,686
406000022	UPGRADE ELEVATED PRESSURE 20			1,999,080			1,999,080
406000023	UPGRADE ELEVATED PRESSURE 21				2,000,000		2,000,000
406000024	UPGRADE ELEVATED PRESSURE 22					1,250,000	1,250,000
419000001	Mueller Tapping Equipment	85,615					85,615
419000002	Small Tools 2020 004190			114,827			114,827
438500001	Lees to CR Piggability Mod	230,072					230,072
445000000	SMALL TOOLS 2018	14,983					14,983
445000001	SMALL TOOLS 2019		14,851				14,851
445000002	SMALL TOOLS 2020			14,851			14,851
447000001	Doe Run Storage Piggability	835,259	1,081,981				1,917,241
447000002	Muld Station Control Rm Repl	196,147	797,022				993,169
447000003	Shale Gas Recovery Injctn Pur	121,342	569,912				691,253
447000004	Muldraugh Station Piping Repl	1,731,550					1,731,550
447000005	Tank Level Wireless Transmit		30,016				30,016
447000006	Mul Station Pipe Repl 2019		1,573,737				1,573,737
447000007	Repl Processers & IO Mod 2020			74,884			74,884
447000008	Muld Station Eng & Comp Upg			172,378			172,378
447000009	Tanks Storage Field & St Waste			58,010			58,010
447000010	Compr Eng Auto Balance Equip			495,017			495,017
447000012	Muldraugh Piggability Project			978,882			978,882
447000013	Muld Compr Unit Surge Tank Rep			255,370			255,370
447000014	Muld Turbine Compr Unit 9 & 10			353,295			353,295
447000015	Muldraugh Piping Repl 2020			941,712			941,712
447000016	ADD/REPLACE ENGINE COOLERS	281,071					281,071
447000017	Muldraugh Backhoe 2020			139,969			139,969
447500001	Install Cntrl Vlvs Wells 2018	202,530					202,530
447500002	Install Cntrl Vlvs Wells 2019		188,707				188,707
447500003	Install Cntrl Vlvs Wells 2020			195,648			195,648
447500004	CONV DR DEEP TO UPPER 2020			406,919			406,919
447500005	DRILL WELLS MAG DEEP 2020			1,019,350			1,019,350
447500006	DRILL WELLS MAG UPPER 2020			994,477			994,477
447500007	DRILL WELLS CENTER 2020			943,503			943,503
447500008	DRILL OBSV WELLS MULD 2020			517,687			517,687
448000001	Station PLC Upgrade	95,623					95,623
448000004	Cooler Handrails/ Platforms	50,027					50,027
448000005	Mag Field Int Corrosion Mit	69,785	70,258	40,409			180,452
448000007	Purchase CNG trucks	25,143					25,143
448000008	Etown Hodgenville Distr Upg		574,439				574,439
448000011	Magnolia Paving		83,023				83,023
448000012	Mag Cathodic Protection Sys		109,095	489,275			598,370
448000014	Purchase CNG trucks 2019		49,867				49,867
448000015	Storage Field Barricades 2020			49,669			49,669
448000016	Security Upg at Mag & Center			49,997			49,997
448000018	Storage Field Trunkline Mod			698,783			698,783
448000019	Magnolia Distribution			296,937			296,937

Project	Description	2018	2019	2020	2021	2022	Grand Total
448000020	Disposal Well				1,199,792		1,199,792
448000021	Packing Vent Measurement			94,768			94,768
448000022	Magnolia Engine Room Floor			97,110			97,110
448000023	Portable Loading dock 2020			30,770			30,770
448000024	Small Tools 2020 004480			42,437			42,437
448000025	Purchase Dozer			199,462			199,462
448000026	Small Tools 2018 004480	40,656					40,656
448000027	Small Tools 2019 004480		41,378				41,378
450000001	Upg SCADA and FT Sys Data Comm	29,748					29,748
450000002	Ballardsville St Eq Ret & Rem	70,250					70,250
450000003	Cyber Sec Prot Eq Muld & Mag	151,738					151,738
450000005	Upgrade CG Transmitters			29,477			29,477
450000006	Doe Run City Gate Station			300,161			300,161
450000007	Enh Security CG & Lrg Reg Sta			49,631			49,631
450000008	Small Tools 2020 004500			29,701			29,701
450000009	Small Tools 2018 004500	29,965					29,965
450000010	Small Tools 2019 004500		29,701				29,701
451000001	Small Tools 2018 004510	29,966					29,966
451000002	Small Tools 2019 004510		29,702				29,702
451000003	Small Tools 2020 004510			29,702			29,702
451000004	Repl Vlv at CG & Dist Reg Fac			98,984			98,984
460000001	Small Tools 2020 004600			14,851			14,851
460000002	Small Tools 2018 004600	14,983					14,983
460000003	Small Tools 2019 004600		14,851				14,851
CACMIT445	AC_MITIGATION	339,596	337,775	1,174,004	1,175,000	1,175,000	4,201,375
CCAPAC451	GAS REG CAPACITY PRO	601,877	599,018	598,944			1,799,840
CCGUPG451	UPGR FACIL CG STATION 2017	49,621	49,534	50,038			149,193
CCOCNT451	RET/REPL CONTR CG STA 2017	60,549	60,000	59,973			180,521
CCPIMP445	CP IMPRESSED CUR SYS IMPROVE	30,891	31,914	31,914			94,719
CCSO419	REPL EXIST CUST SRV W RISER	1,977,728	2,026,786	2,081,683	2,139,000	2,193,000	10,418,198
CCSO421	REPL EXIST CS WITH RISER-MUL	140,872	144,247	147,948	152,000	156,000	741,067
CCSO4485	REPL EXIST CS & RISER-4485	99,382	98,995	98,855	102,000	104,002	503,235
CDEFEQ447	MULDR FAC IMP/EQ REPLACE	176,090	179,977	186,220			542,287
CDEFEQ448	MAG FAC IMP/EQ REPL	145,617	150,191	154,332			450,140
CFTCUS450	FT CUSTOMER CONVERSIONS	90,484	89,672	89,490			269,646
CGME406	NB Gas Main Ext - 004060	1,900,132	2,252,676	2,318,145			6,470,953
CHPSRV451	COMM HIGH PRES GAS SRV UPGR 17	525,970	524,562	524,434			1,574,967
CNBCS419	NB CUST SRV LINE & GAS RISER	4,295,986	4,402,070	4,525,378	4,691,000	4,808,004	22,722,439
CNBCS421	NB INST CUST SERV LINE & RSR	23,840	22,649	24,125	24,000	24,000	118,614
CNBCS4485	INST CUST SRV - MAGNOLIA	23,217	23,136	24,159	25,000	26,002	121,514
CNBGS419	NB Gas Services - 004190	1,844,589	1,890,880	1,942,909			5,678,379
CNBREG451	PURCH REGULATORS - 004510	115,581	114,562	114,562			344,704
CPBWK406G	Gas Public Works - 004060	1,347,958	1,384,162	1,424,926			4,157,046
CPLUG4475	PLUG GAS STOR WELLS COR CASE	807,980	835,979	876,999			2,520,958
CRCST406G	Cust Requested - 004060	1,255	-	-			1,255
CREGFC451	GAS REG FAC UPGRADE BLKT 2017	641,485	639,392	639,253			1,920,130
CREGST451	UPGR FACIL DIST REG STATIONS	49,824	49,780	49,766			149,371
CRELI4475	RELINE GAS STORAGE WELLS 2016	176,199	176,881	186,807			539,887
CROTAR451	UPRG OBSOL ROTARY METERS	99,551	99,061	99,013			297,625
CRSS414	REPLACE STEEL SERVICE LINES	9,422,519			4,832,000	5,019,000	19,273,519
CSTATN447	MULD STATION BLKT	494,162	507,261	522,549			1,523,972
CSTATN448	MAGNOLIA STATION BLKT	275,508	398,857				674,365
CSTOR447	MULD STOR FIELD/TRANS BLKT	1,101,800	1,149,376	1,147,342			3,398,518
CSTOR448	MAG STOR FIELD/TRANS BLKT	486,679	501,278	520,080			1,508,036
CSYSEN406	Sys Enh - 004060	734,588	744,138	766,874			2,245,600
CTBRD419	Cap Trbl Orders Gas - 004190	224,190	229,924	236,905	191,000	196,000	1,078,019
CTPD419	Capital Thrd Party - 004190	166,966	170,579	177,313	139,000	143,000	796,858
DLSMR414	DWNTWN LRG SCALE MAIN	6,868,626	3,572,391				10,441,017
LSMR414	Large Scale Main Replacements	4,753,730	2,476,958				7,230,688
RRCS419G	REP CO GAS SERV 419	2,658,390	2,725,659	2,801,582	2,897,000	2,970,000	14,052,631
RRCS421	Serv Line Repl-Muldraugh	169,305	174,000	177,678	182,000	186,000	888,982
TMP414	Transmission Modernization			29,987,089	35,000,000	25,000,000	89,987,089
TMPPENBLN	TMP PENILE-BLANTON LN	2,010,148	20,226,540				22,236,688
TMPPENPRS	TMP PENILE-PRESTON	20,686,032					20,686,032
TMPPRSPIC	TMP PRESTON-PICCADILLY	2,164,242	22,664,166				24,828,408
153931	AMS Meters - LGE	6,504,449	23,542,358	28,250,830	9,416,943		67,714,580
153932	AMS Meters - LGE GAS	2,787,621	10,089,582	12,107,498	4,035,833		29,020,534
154013	AMS MAM System 2017 LG&E	1,920,160					1,920,160
155484	AMS IT Systems - LG&E	8,098,728	24,215,400	12,509,200	1,540,000		46,363,328
155497	AMS Network-Communications LGE	427,680	1,558,658	1,870,389	623,463		4,480,190
123885	GS LGE Drw Mgmnt System		122,248				122,248
123906LGE	BRCT6 C Inspection LGE		8,609,648				8,609,648
124090	MC Limestone Unld Bucket		58,487				58,487
124499	TC CBU SURGE BIN ROOF REPL				222,183		222,183
124518	TC1 RECYC PUMP PIPING EBW	367,525	369,002	373,516	384,722	396,263	1,891,027
124526	TC COAL YARD BUILDING SIDING	57,983	58,217	58,929	60,696		235,825
126645	GS-LGE-TOGAS Analyzer			34,595			34,595
127578	MC4 Economizer	750,000					750,000
127590	MC4 Condenser	1,410,000					1,410,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
131363	ZN GT Control Upgrade 2015				832,000		832,000
131915	Scanning Equip-LGE			43,956	46,374		90,330
131972LGE	BRCT7 C Inspect-LGE				9,775,746		9,775,746
132002	TC CT HGP Insp Unit 7	1,532,399	503,632				2,036,031
132003	TC CT HGP Insp Unit 9			2,048,934			2,048,934
132004	TC CT HGP Insp Unit 8				2,546,929		2,546,929
132756	GS GE Lab Equip		56,773	56,980	58,201	59,422	231,376
132925	MC4 Circ Water Line				200,000	3,500,000	3,700,000
132931	GS CDM Lrg Format LGE			62,678	68,783		131,461
132960	MC1 DCS 2021	300,000	650,000				950,000
132967	MC4 Precipitator 2018	1,000,000					1,000,000
132976	MC Dozer #1 Refurbishment		1,000,000				1,000,000
132980	MC Dozer #2 Refurbishment		1,000,000				1,000,000
132986	MC1 Turbine Water Induction				1,587,962		1,587,962
132989	MC2 Relays			566,592			566,592
132996	MC3 Relays				558,185		558,185
133000	MC3 Circ Water Line			200,000	3,500,000		3,700,000
133076	GS GE Dam Impnd	41,170	39,228	37,675	36,121	34,568	188,762
133615LGE	TC PLT ENG/MTR RWNDS	276,672	277,784	281,181	289,617	298,306	1,423,561
133622LGE	TC LAB PURCH MONITORS	95,748	96,133	97,309	100,228	103,235	492,654
133627LGE	TC LAB EQUIP PURCHASES	59,826	60,066	60,801	62,625	64,504	307,821
133653LGE	TC SAFETY & ERT EQUIP	60,618	60,863	61,607	63,465	65,369	311,921
133710LGE	TC RPL FIRE SYS UNGRD PIPE					121,414	121,414
134109	TC1 MDCT Fill & DE Replac			299,093	308,065	319,032	926,190
134113LGE	TC2 SCR L3 REPLACEMENT	391,027					391,027
134176	TC1 SDRS REPL DEMISTER WASH			625,103	1,682,276		2,307,379
134404LGE	TC2 CONVERT DOORS			43,297			43,297
135120	MC4 PJFF Bags 2018			2,220,884			2,220,884
135122	MC1 PJFF Bags 2019	1,150,000	224,521				1,374,521
135123	MC2 PJFF Bags 2018		1,062,507	219,243			1,281,750
135124	MC3 PJFF Bags 2019				2,040,726		2,040,726
135126	MC1 PJFF BC 2023					1,700,001	1,700,001
135236	TC1_PJFFB&C		1,701,303				1,701,303
135245LGE	TC2 PJFF B&C	326,800					326,800
135252LGE	TC2_PJFF B&C					348,969	348,969
136480	GS GE Test Equip Pool LGE	72,976	69,404	85,800	85,800	87,158	401,138
136560	GS SL Mer Coal Anlzr LGE			55,000			55,000
136562	GS SL Coal Mstr Ash Anlzr LGE			104,500			104,500
136564	GS SL BTU Calrmtr LGE				82,500		82,500
136565	GS SL Oil Dlctrc Test LGE				27,500		27,500
136566	GS SL Oil Pwr Fact Test LGE				44,000		44,000
136567	GS SL Slfr Oil Anlzr LGE					60,500	60,500
136568	GS SL Veh 7628 Rpl LGE					38,500	38,500
136636	MC3 SCR Catalyst Layer 1		1,918,841				1,918,841
136642	MC2 FWTR HTRS Phase 1	1,068,000					1,068,000
136660	MC3 Expansion Joints 2017	100,000					100,000
137039	TC1 RPLCE AIR HEATER BASKETS		1,313,089				1,313,089
137585LGE	TC2 DCS UPGRADE		373,886				373,886
137587	TC1 DCS UPGRADE		1,103,370				1,103,370
137633LGE	TC2 SLMS UNIT	26,814					26,814
138395	TC1 SH FRONT PLATEN		161,910				161,910
138400	TC1 SH DMW REPLACE		217,388				217,388
139595	GS GE DME Phase II LGE	25,125					25,125
139682LGE	TC PREDICTIVE DEVICES MAINT	20,081	20,161	20,408	21,020	21,650	103,319
139709	MC4 Dearator Heater				287,389	1,287,389	1,574,777
139715	MC4 Vac Pump Chilled Wtr			241,592			241,592
139717	MC Limestone Barge	1,580,000					1,580,000
139718	MC4 Inter SH Pendants	1,500,000					1,500,000
139719	MC3 Dearator Heater			287,389	1,183,185		1,470,573
139721	MC 3C GSU Transformer		425,000				425,000
139725	TC1 REPLACE TURBINE ROOM ROOF		518,385				518,385
139767	MC CH Railroad Track 2018	175,000					175,000
139769LGE	TC REPL FIRE SYST CRUSH HOUSE				155,910		155,910
139786	TC1 SCR STRUCT STEEL BYPASS		207,533				207,533
139787	TC1 INST EOD'S TDBFP TURBINES				883,527		883,527
139800LGE	TC UPGRD RO SYSTEM			42,728			42,728
139814	MC Matl Handling Chutes 2018	250,000					250,000
139821	MC3 SCR Catalyst L2	560,000					560,000
139830	MC4 SCR CATALYST L3 2018	1,366,000					1,366,000
139836	MC2 Expansion Joints 2018	100,000					100,000
139841	MC4 Expansion Joints 2018	105,000					105,000
139851	MC Misc Equipment 2018	700,000					700,000
139861	MC3 BOILER TUBING					1,915,924	1,915,924
139867	MC4 BOILER TUBING				478,981	3,300,000	3,778,981
139873	MC1 TURB MISC		3,957,121				3,957,121
139876	MC2 TURBINE MISC	3,000,000					3,000,000
139878	MC3 TURB MISC		2,464,688				2,464,688
139879	MC4 TURB MISC					4,420,128	4,420,128
139880	MC1 FDWTR HTRS Phase 1	332,000	928,000				1,260,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
139884	MC2 AIR HTR BASKETS	1,350,000					1,350,000
139886	MC2 FDWTR HTRS Phase 2				766,370	989,491	1,755,860
139889	MC3 AIR HTR BASKETS		1,478,561				1,478,561
139892	MC3 FDWTR HTRS	22,000	1,041,000				1,063,000
139897	MC4 FDWTR HTRS	1,109,000					1,109,000
139900	MC Coal Bucket			201,172			201,172
139901	MC Conveyor Belts 2018	275,000					275,000
139902	MC Safety Equipment 2018	35,000					35,000
140014LGE	TC CT DCS UPGRADE		90,428				90,428
140032LGE	TC PURCHASE JLG LIFT				97,988		97,988
140048LGE	TC2 TURBINE CONTROLS UPGRADE	108,092					108,092
140157	CR GT11 Gas Reg Station				341,000		341,000
140342LGE	OG MISC TOOLS LGE	17,841	37,391	81,216	31,846	19,598	187,892
140344LGE	OG KEY SEATER LGE	29,735					29,735
140604LGE	TC2 ID FAN BLADE SETS				64,946		64,946
140606LGE	TC2 BATTERY REPLACEMENTS					39,874	39,874
140611LGE	TC CRUSHER BIN REDUNDANCY				1,577,850		1,577,850
140614LGE	TC2 EXPANSION JOINTS	84,745					84,745
140619LGE	TC CONVEYOR BELT REPLACE	137,733	138,374	287,129	296,244	305,359	1,164,839
140654LGE	TC CBU BKT & CHAIN	420,366			893,005		1,313,371
140659LGE	TC CT LCI UPGRADE #2		117,583				117,583
140660LGE	TC CT LC1 UPGRADE #3	127,095					127,095
142399	MC3 Gen Stator Bar Install		3,000,000				3,000,000
143591	MC CH Railroad Track 2019		171,847				171,847
143592	MC Material Hndlg Chutes 2019		244,955				244,955
143595	MC4 SCR Catalyst L1 2020			2,370,281			2,370,281
143596	MC4 SCR Catalyst L4 2022 1					2,516,876	2,516,876
143600	MC1 Expansion Joints 2019		99,243				99,243
143601	MC3 Expansion Joints 2019		99,243				99,243
143603	MC Misc Equipment 2019		700,000				700,000
143604	MC2 DCS 2020	900,000					900,000
143605	MC3 DCS (2019)		1,279,822				1,279,822
143606	MC4 DCS 2022				1,300,000		1,300,000
143609	MC Conveyor Belts 2019		269,955				269,955
143611	MC Safety Equipment 2019		34,117				34,117
143619	MC2 Boilr Upper Arch				1,436,943		1,436,943
143629	MC3 Waterwall Panels and TS	1,398,000					1,398,000
143633	MC Misc Lab Equipment 2018	65,000					65,000
143634	MC Misc Lab Equipment 2019		63,361				63,361
143635	MC2 Turb L-0/L-1 Buckets	1,950,000					1,950,000
143637	MC3 Turbine L-0 Buckets 2019	1,000,000	2,974,777				3,974,777
144494	GS GE PDM Equip Upgrade			35,409			35,409
144503	GS CDM GMD Protection		20,720	21,164	21,571	44,322	107,777
144510	GS CDM CIP Ver 7.0 LGE		70,034				70,034
144514	GS CDM CIP Ver 8.0 LGE			50,875	52,910		103,785
144516	GS CDM Communications Upgrade					40,700	40,700
144530	OF Trash Racks (multi-year)		90,767	90,985	92,805	94,661	369,219
144531	CR7 Misc Project (multi-year)	88,234	116,050	116,319	118,646	121,019	560,267
144542	CR7 NGCC HGP (2019)		4,983,750				4,983,750
147035	MC CH Railroad Track 2020			170,796			170,796
147036	MC Matl Handling Chutes 2020			241,592			241,592
147042	MC2 Exp Joints 2020			98,739			98,739
147043	MC4 Exp Joints 2020			98,739			98,739
147046	MC2 Cooling Tower Rebuild				718,471	3,186,497	3,904,969
147048	MC 3 and 4 Spare GSU Trans		1,462,166				1,462,166
147049	MC Misc Equipment 2020			700,000			700,000
147053	MC1 Boiler Lower Slope			862,166	1,915,000		2,777,166
147054	MC1 Reheat Outlet Header		996,217				996,217
147056	MC2 Boiler Lower Slope		877,299	1,915,000			2,792,299
147057	MC2 Reheat Outlet Header	800,000					800,000
147058	MC3 Econ Inlet Header		1,300,911				1,300,911
147060	MC3 Rear Slope & Lower WW			862,166	2,000,000		2,862,166
147061	MC4 IR Panels	1,660,000					1,660,000
147062	MC Misc Lab Equipment 2020			67,057			67,057
147068	MC Conveyor Belts 2020			241,592			241,592
147069	MC Stacker/Reclaimer	1,300,000	7,599,109				8,899,109
147070	MC Safety Equipment 2020			33,529			33,529
147078	MC 1&2 Reactant Supply Loop		2,217,210				2,217,210
147079	MC 3&4 Reactant Supply Loop			2,195,351			2,195,351
147080	MC3 SCR Catalyst L4 2021				2,348,343		2,348,343
147082	MC2 Voltage Regulator	70,000					70,000
147083	MC3 Voltage Regulator	75,000					75,000
147084	MC4 Voltage Regulator			72,268			72,268
147455	TC1 SCAFFOLD DOOR UPGRADE				238,865		238,865
147470LGE	TC C COAL CONVEYOR SPARE MTR			149,546			149,546
148083	OF Bridge Resurface	50,000					50,000
148084	OF Asphault Repl	35,000					35,000
148086	PR13 CEMS Installation		191,833				191,833
148096	CR7 NGCC STG (2019)		154,277				154,277

Project	Description	2018	2019	2020	2021	2022	Grand Total
148104	CR7 Annual Outage (2020)			53,153			53,153
148115	CR7 DCS Controls Plat	121,054					121,054
148132	GS GE CV Landfill Instrum	40,423	40,197	40,293	41,107	41,921	203,940
148135	GS GE CV GIS			40,700	40,700	40,700	122,100
148139	GS GE ME Turbine Monitoring				122,100		122,100
148155	GS CDM CIP Ver 9.0				61,050	63,085	124,135
148162	GS CDM Cascade Tablet				6,105		6,105
148167	GS CDM MOD 025				23,199		23,199
148175	GS CDM Industrial Defender	79,550	38,830				118,380
149019LGE	TC2 TDBFP RECIRC VALVE A	29,623					29,623
149021LGE	TC2 TDBFP RECIRC VALVE B			32,473			32,473
149023LGE	TC INSTALL MTR VALVE 8A&8B FWH			213,317			213,317
150000LGE	TC SITE PAVING			136,421			136,421
150011LGE	TC2 BOILER WATER LANCES				38,938		38,938
150013LGE	TC2 BURNERS REPL (A,D ROWS)	46,610					46,610
150015LGE	TC2 BURNER NOZZLE REPL		46,797				46,797
150016LGE	TC2 BURNERS REPL (B,E ROWS)	25,423					25,423
150017LGE	TC2 BURNERS (C,F ROWS)		25,525	25,838			51,364
150018LGE	TC2 COAL FLOW ANALYZERS	42,372	46,021	8,118	8,443		104,955
150031LGE	TC ASH POND MOWERS	55,664		56,970			112,634
150034LGE	TC2 COAL MILL AREA HOIST UPG	16,949					16,949
150035	TC1 UPPER ARCH REPLACEMENT	133,808	290,382				424,190
150037	TC1 UPPER ARCH REPLACEMENT					213,638	213,638
150039	TC1 FRONT RH ASSEMBLY REPL					640,913	640,913
150042LGE	TC WAREHOUSE D				207,880		207,880
150043LGE	TC WHSE FORKLIFT/PALLETT RACK			45,576			45,576
150044LGE	TC WHSE TRUCK				47,627		47,627
150045LGE	TC UPG TC WHSE SECURITY			36,379			36,379
150049LGE	TC REPL LST TANK FLOORS			78,316		94,786	173,102
150051LGE	TC2 WESP WASH WATER PIPING					41,531	41,531
150052LGE	TC2 LOWER SLOPE WW REPL		33,043	103,680			136,723
150053LGE	TC ELECTROMECH RELAY	169,490	165,215	162,365	162,365	170,910	830,343
150054LGE	TC2 SSC CHAIN	17,774					17,774
150055LGE	TC2 SH PENDANT REPL		51,795	139,301			191,096
150056LGE	TC2 RH PLATENT REPL				89,300	244,389	333,689
150057LGE	TC2 REMOVE MAIN STOP VALVES			45,434			45,434
150058LGE	TC COAL HAND BUILD ROOF REPL	23,193					23,193
150059LGE	TC UPG COAL HAND SAMPLER			128,183			128,183
150060LGE	TC COAL HAND BYPASS GATE	46,387					46,387
150064LGE	TC2 SSC TILE			75,957			75,957
150065LGE	TC WASTE PUMPS SLUDGE PIT		33,912				33,912
150067LGE	TC A LSTONE CONV FLOP GATE					152,680	152,680
150070LGE	TC COAL BLEND TUNNEL N SIDE			222,183	2,392,013		2,614,196
150073LGE	TC ADD HEAT TO BINS & CHUTE			23,230			23,230
150074LGE	TC E4 CONVEYOR			444,366	1,333,098		1,777,464
150077LGE	TC REPL SEWAGE TREAT PLANT			162,527	88,873		251,401
151000	TC1 & COMM 480V BREAK UPG		86,955				86,955
151003	TC1 FGD INLET FLOW MONITORS					267,901	267,901
151005	TC1 OXIDATION AIR BLOWERS			260,923	152,680		413,602
151006	TC2 NOX PROBE GRID			339,283			339,283
151010	TC1 COAL CONDUITS			130,433			130,433
151015	TC1 BURNERS (C,D ELEVAT)		460,862				460,862
151016	TC1 BURNERS (E,F ELEVAT)				479,687		479,687
151021	TC1 ELECTROMECH RELAYS		364,340		341,820		706,160
151027	TC1 EMERGENCY GENERATE UPG					427,275	427,275
151029	TC1 DEMISTER WASH PUMP UPG					43,297	43,297
151240	MC CH Railroad Track 2021				170,796		170,796
151242	MC Matl Handling Chutes 2021				291,592		291,592
151243	MC Limestone Lining Screw A			212,013			212,013
151244	MC Limestone Lining Screw B	210,000					210,000
151245	MC Limestone Lining Screw C		210,334				210,334
151246	MC1 Expansion Joints 2021				98,739		98,739
151247	MC3 Expansion Joints 2021				98,739		98,739
151249	MC Plant Fire Protection		400,000		400,000		800,000
151251	MC1 Turbine Room Roofing			250,000			250,000
151252	MC2 Clg Tower Serv Bldg Roof	50,000					50,000
151253	MC3 Sootblower Steam Source	60,000					60,000
151255	MC 3B GSU Transformer Install		425,000				425,000
151258	MC2 Field Instrumentation 2018	400,000					400,000
151259	MC3 Field Instrumentation 2019		394,955				394,955
151260	MC Misc Lab Equipment 2021				71,847		71,847
151262	MC Coal Handling Switchgear				1,000,000		1,000,000
151265	MC Misc Equipment 2021				700,000		700,000
151267	MC1 Switchgear/MCC				1,500,000		1,500,000
151269	MC3 Generator Brush Rigging	100,000					100,000
151272	MC4 Switchgear/MCC					1,500,000	1,500,000
151275	MC1 CCWHE Yuba Coolers			383,185	683,185		1,066,370
151283	MC3 Cooling Tower Structure				950,000		950,000
151284	MC Conveyor Belts 2021				266,592		266,592

Project	Description	2018	2019	2020	2021	2022	Grand Total
151285	MC Safety Equipment 2021				33,529		33,529
151286	MC 3B Coal Mill Gearbox	256,000					256,000
151287	MC Sump Pumps	60,000					60,000
151288	MC4 Thermal Spray			1,443,694			1,443,694
151291	MC Coal Barge Unloader MCC			293,694			293,694
151574	MC1 Boiler Air Tips				244,745		244,745
151577	MC1 Sootblower		246,217				246,217
151578	MC2 Boiler Air Tips			244,745			244,745
151579	MC2 Burners					664,491	664,491
151582	MC3 Coal Piping	250,000					250,000
151585	MC 3A Burner Nozzles				242,433		242,433
151586	MC 3B Burner Nozzles				242,433		242,433
151587	MC 3C Burner Nozzles				242,433		242,433
151588	MC 3D Burner Nozzles				242,433		242,433
151590	MC 4A Burner Nozzles			242,433			242,433
151591	MC 4B Burner Nozzles			242,433			242,433
151592	MC 4C Burner Nozzles			242,433			242,433
151593	MC 4D Burner Nozzles			242,433			242,433
151594	MC 4E Burner Nozzles			242,433			242,433
151782	MC3 DCS Hardware 2018	100,000					100,000
151783	MC2 DCS Hardware 2019		100,000				100,000
151784	MC1 DCS Hardware 2020			97,057			97,057
151857	MC Landfill Closure 2018	263,000	275,000	275,000	275,000	275,000	1,363,000
151949	CR7 Raw Water Intake	11,000					11,000
151980	OF DCS Conv/Upgrade				1,469,000		1,469,000
152001LGE	TC CT EX2000 DIGITAL FE CT10		61,709				61,709
152004LGE	TC CT EX2000 DIGITAL FE CT7	67,252					67,252
152005LGE	TC CT EX2000 DIGITAL FE CT8	67,252					67,252
152006LGE	TC CT EX2000 DIGITAL FE CT9		69,284				69,284
152007LGE	TC CT LUBE OIL PUMPS				52,276		52,276
152008LGE	TC CT WATER WASH SYST UPG				284,565		284,565
152009LGE	TC CT BULK CO STORAGE	253,342					253,342
152013LGE	TC CT MARK VI UPGD CT7	85,417					85,417
152014LGE	TC CT MARK VI UPGD CT8	100,676					100,676
152015LGE	TC CT MARK VI UPGD CT9		98,137				98,137
152016LGE	TC CT MARK VI UPGD CT10		93,751				93,751
152030LGE	TCCT UPG FIRE PROTECT				227,880	234,716	462,596
152032LGE	TC CT HMI UPGRD		149,985				149,985
152038LGE	TC CT SECURITY ST	41,576					41,576
152040LGE	TC2 SSC REPLACE CHAIN					88,906	88,906
152042LGE	TC2 SSC FLIGHT REPLACE			53,028			53,028
152049LGE	TC2 BOILER WATER WALL REPL	785,139					785,139
152050	CR7 Station Support Building	30,030					30,030
152052	CR7 Compressor Wash Sys			107,955			107,955
152055	CR7 T3K Hardware Refresh		141,689				141,689
152056	PR13 T3K Hardware Refresh		304,777				304,777
152057	CR7 Annual Outage (2018)	53,331					53,331
152058	CR7 Annual Outage (2019)		54,398				54,398
152059	CR7 Annual Outage (2021) L				56,596		56,596
152061LGE	TC2 REPL ZED PLATE & REFACTORY	33,895					33,895
152063	TC1 REAR WW HANGER TUBES		80,955				80,955
152064	TC1 WATER WALL PANELS					213,638	213,638
152065	TC1 REAR WW HANGER TUBE				97,546		97,546
152066	TC1 FRONT COUT SLOPE PANEL		161,910				161,910
152068LGE	TC2 BOILER WWALL 2018	76,195					76,195
152070LGE	TC SHUTTLE BARGE WINCH UPG		104,346				104,346
152079LGE	TC OVATION SECUTY CENTER			101,342			101,342
152081	TC1 EXP JOINTS		359,559				359,559
152092LGE	TC B BALL MILL LINER UPGD	131,389					131,389
152097LGE	TC RAT RELAYS LGE		66,885				66,885
152099LGE	TC2 HP TURBINE BLADES LGE	169,490					169,490
152126	GS GE TR ONLINE DGA	51,060	49,728	48,840			149,628
152128	GS SL GAS GC	25,530					25,530
152652LGE	TC2 BOILER WW		303,069				303,069
152654LGE	TC GYPSUM DEWATERING BELT LGE					88,873	88,873
152659LGE	TC2 A ID FAN OVERHAUL LGE			156,380			156,380
152661LGE	TC2 B ID FAN OVERHAUL LGE				161,594		161,594
152663LGE	TC2 A FD FAN OVERHAUL LGE					43,069	43,069
152665LGE	TC2 B FD FAN OVERHAUL LGE			62,310			62,310
152667	TC1 BCWP OVERHAUL		123,524		128,786		252,310
152670	TC1 TDBFP PUMP OVERHAULS		127,776				127,776
152683LGE	TC2 B BFP OVERHAUL LGE		31,427				31,427
152685LGE	TC2 B BFP OVERHAUL LG&E			33,341			33,341
152693LGE	TC OFFICE UPGRADES LGE	92,773	93,146	98,649	103,028		387,597
152695LGE	TC2 MS TURBINE BVO		41,271				41,271
152697LGE	TC2 HRH TURBINE BVO	59,321					59,321
152772	CR7 CT 1&2 Insulation		418,660				418,660
152776	CR7 DCS Hardware Refresh					105,278	105,278
152895	CR7 Annual Outage (2022)					57,727	57,727

Project	Description	2018	2019	2020	2021	2022	Grand Total
152920	CR11 DCS Conv (2022)				574,000		574,000
152921	PR11 DCS Conv (2022)				574,000		574,000
152922	PR12 DCS Conv (2022)				574,000		574,000
153002LGE	TC CCR DRY VAC EQUIPMENT			165,213			165,213
153003	TC1 CEM PM MONITOR CHANGE	77,955					77,955
153009	TC1 CEM FLOW MONITOR CHANGEOUT		74,113				74,113
153010	TC1 CEM ANALYZER CHANGEOUT			46,715			46,715
153017LGE	TC2 PCM Hg MONITOR UPGRADE		61,129				61,129
153018LGE	TC2 A CEM FLOW MONITOR CHANGE		13,217				13,217
153019LGE	TC2 B CEM FLOW MONITOR CHANGE		13,217				13,217
153020LGE	TC2 A CEM UMBILICAL CHANGOUT			2,814			2,814
153021LGE	TC2 B CEM UMBILICAL CHANGEOUT			2,814			2,814
153022LGE	TC2 A CEM ANALYZER CHANGEOUT			21,920			21,920
153023LGE	TC2 B CEM ANALYZER CHANGEOUT			21,920			21,920
153028LGE	TC FUEL BLEND FEEDER REPL				85,455	85,455	256,365
153031LGE	TC2 BOILER DRAIN RECOV FILTER			37,029			37,029
153034LGE	TC2 UPG SAMPLE LINES SWAS	25,423					25,423
153044LGE	TC2 UPPER ARCH REPL-				48,709	133,303	182,012
153047LGE	TC2 FINAL SH REPL*				36,533	104,978	141,510
153049LGE	TC2 PRI SH REPL-		16,521	63,528			80,050
153050LGE	TC2 PRI SH REPL				20,296	56,543	76,840
153053LGE	TC2 GEN EXCITATION REPL	171,573					171,573
153055LGE	TC2 MDBFP START UPG	29,623	74,057				103,680
153056LGE	TC IMPOUNDMENT IMPROVEMENTS	356,820	347,820	256,365			961,005
153060LGE	TC2 REPL AH CE BASKETS				162,365	148,115	310,479
153066	TC1 RE-INSULATE BOILER				116,933		116,933
153070LGE	TC CT PEEC BATTERIES			25,295	25,295	25,295	75,884
153072LGE	TC FUEL HANDLING DOZER				1,196,370		1,196,370
153077	TC1 SCR CATALYST L2 NEW	218,552	2,285,351				2,503,903
153078	TC1 SCR CATALYST L3 NEW			226,456	2,018,708		2,245,164
153079	TC1 SCR CATALYST L1-					240,129	240,129
153080LGE	TC2 SCR CATALYST L1 NEW-		148,978	437,224			586,202
153081LGE	TC2 SCR CATALYST L2 NEW				132,461	397,384	529,845
153095LGE	TC CT GFI UPGRADE			48,222			48,222
153098LGE	TC CT REBUILD EXHAUST EXP JNTS	124,652					124,652
153099LGE	TC CT REBUILD EXHAUST EXP JNTS			122,994			122,994
153101LGE	TC CT REBUILD EXHAUST EXP JTS+				140,024		140,024
153873	MC CH Railroad Track 2022				169,745		169,745
153874	MC Matl Handling Chutes 2022				291,592		291,592
153875	MC2 Expansion Joints 2022				98,949		98,949
153877	MC4 Expansion Joints 2022				98,949		98,949
153879	MC Misc Lab Equipment 2022				76,637		76,637
153880	MC Misc Equipment 2022				683,185		683,185
153881	MC Conveyor Belts 2022				290,541		290,541
153882	MC Safety Equipment 2022				33,529		33,529
153884	MC3 Cooling Tower Elect Cable		750,000				750,000
154201	MC3 Econ Inlet Check Valve	45,000					45,000
154202	MC4 Econ Inlet Check Valve	45,000					45,000
154322	CR7 Bypass Valve Upgrade	55,000					55,000
154324	MC Flyash Silo "A" Baghouse		600,000				600,000
154325	MC Flyash Silo "B" Baghouse				600,000		600,000
154326	MC GPP Secondary Surge Tank			500,000			500,000
154327	MC Basement Water Piping		200,000	200,000	200,000		600,000
154328	MC Perform Monitoring Software	100,000					100,000
154329	MC 1A Circ Wtr Pump OVERHAUL	200,000					200,000
154331	MC1 Hydrogen Coolers		244,703				244,703
154332	MC2 Hydrogen Coolers		244,703				244,703
154333	MC2 Turbine Water Induction					300,000	300,000
154334	MC3 Attemperator Spray Valve	250,000					250,000
154338	MC3 Hydrogen Coolers		244,703				244,703
154341	MC4 Hydrogen Coolers		244,703				244,703
154344	MC4 Mist Eliminators					1,253,758	1,253,758
154375	MC2 Service Water Valves	60,000					60,000
154376	MC3 Service Water Valves	100,000					100,000
154377	MC1 & MC2 Hg CEMS			281,641			281,641
154378	MC1 & MC2 Hg Trap System			107,292			107,292
154379	MC1 & MC2 PM Probe			154,232			154,232
154380	MC3 Hg CEMS				281,641		281,641
154381	MC3 Hg Trap System				107,292		107,292
154382	MC3 PM Probe				154,232		154,232
154383	MC4 Hg Trap System		109,175				109,175
154384	MC4 Hg CEMS		286,584				286,584
154385	MC4 PM Probe		156,939				156,939
154386	MC Coal Barge Unloading PLC	65,000					65,000
154387	MC Coal Hndlg Fire System	300,000					300,000
154388	MC Turbine Room LED Lighting			130,000			130,000
154389	MC1 Fire Protection				150,000		150,000
154390	MC1 LED Lighting				341,592		341,592
154391	MC2 Fire Protection		146,000				146,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
154392	MC2 LED Lighting				341,592		341,592
154393	MC3 Fire Protection				150,000		150,000
154394	MC3 LED Lighting				342,000		342,000
154395	MC3 O2 Probes		248,487				248,487
154396	MC4 Fire Protection				150,000		150,000
154397	MC4 LED Lighting				342,000		342,000
154398	MC4 O2 Probes	250,000					250,000
154399	MC Boiler Video Camera	40,000					40,000
154402	MC1 Primary Air Flow Xmtrs	250,000	100,000				350,000
154403	MC2 Primary Air Flow Xmtrs	350,000					350,000
154404	MC3 Hardware Refresh					100,000	100,000
154405	MC4 Hardware Refresh				100,000		100,000
154406	MC Air Dryer Controls	50,000					50,000
154407	MC Turb Oil Demuls Restoration		97,982				97,982
154408	MC3 Control Valve Steam Chest		1,493,694				1,493,694
154412	MC "B" Reactant Feed Bldg Roof		75,000				75,000
154413	MC Turbine Room Roof Exhaust	620,000					620,000
154414	MC Oil/Water Separator	300,000					300,000
154415	MC1 Service Water Piping		1,200,000				1,200,000
154416	MC Snow Plow Vehicle	50,000					50,000
154463	MC1 Turbine Room Roof Drains				185,000		185,000
154464	MC2 Turbine Room Roof Drains			185,000			185,000
154466	MC4 Turbine Room Roof Drains			230,000			230,000
154540	MC Gypsum Loading System	925,000					925,000
154542	MC4 Secondary Air Meters					966,370	966,370
154543	MC3 Boiler Flame Scanners	138,000					138,000
154544	MC4 Boiler Flame Scanners	166,000					166,000
154547	MC Bottom Ash Hndlg Cap Spares				1,436,943		1,436,943
154548	MC GPP Capital Spares				1,436,943		1,436,943
154552	MC1 Radiant RH - Partial					143,694	143,694
154554	MC1 Rear RH Weld Overlay			287,389	500,000		787,389
154555	MC1 SH Division Pnls - Partial	200,000	375,000				575,000
154556	MC1 WW Weld Overlay 2019	1,000,000	1,955,000				2,955,000
154558	MC2 Radiant RH - Partial				143,694	950,000	1,093,694
154559	MC2 Rear RH Weld Overlay				287,389	500,000	787,389
154560	MC2 SH Division Panels Partial				191,592	375,000	566,592
154561	MC2 WW Weld Overlay 2018	2,600,000					2,600,000
154564	MC3 Front Slope & Lower WW			862,166			862,166
154593	MC2/MC3 Boiler Room Roof Drain		650,000				650,000
154597	MC 1A Blr Circ Pump OVERHAUL			120,796			120,796
154598	MC 1A MDBFP OVERHAUL		147,478				147,478
154599	MC 1A Recycle Pump OVERHAUL	125,000					125,000
154600	MC 1B Blr Circ Pump OVERHAUL					127,082	127,082
154601	MC 1B Circ Wtr Pump Overhaul				197,854		197,854
154621	MC 4A CTP OVERHAUL 2017	100,000					100,000
154630	MC 1B MDBFP OVERHAUL 2021				150,376		150,376
154631	MC 1C BCP OVERHAUL 2021				120,796		120,796
154632	MC 1C Recycle Pump OVERHAUL		122,478				122,478
154633	MC 1E Recycle Pump OVERHAUL			125,796			125,796
154634	MC 2A BCP OVERHAUL 2020			120,796			120,796
154635	MC 2A CTP OVERHAUL 2019		146,973				146,973
154636	MC 2A MDBFP OVERHAUL 2022					155,376	155,376
154637	MC 2A MDBFP OVERHAUL 2018	150,000					150,000
154638	MC 2B BCP OVERHAUL 2018	120,000					120,000
154639	MC 2B CTP OVERHAUL 2020			150,376			150,376
154640	MC 2B MDBFP OVERHAUL 2020			150,586			150,586
154641	MC 2B Recycl Pmp OVERHAUL 2018	125,000					125,000
154642	MC 2C BCP OVERHAUL 2019		117,478				117,478
154643	MC 2D Recyc Pump OVERHAUL 2019		122,478				122,478
154644	MC 2F Recyc Pump OVERHAUL 2020			125,586			125,586
154645	MC 3A CTP OVERHAUL 2019		147,478				147,478
154646	MC 3A Recyc Pump OVERHAUL 2019		122,478				122,478
154647	MC 3B CTP OVERHAUL 2018	150,000					150,000
154648	MC 3B Recyc Pump OVERHAUL 2019		122,478				122,478
154649	MC 3C Recyc Pump OVERHAUL 2020			125,586			125,586
154650	MC 3D Recyc Pump OVERHAUL 2020			125,586			125,586
154651	MC 3E Recyc Pump OVERHAUL 2021				125,796		125,796
154652	MC 4A CTP OVERHAUL 2022					30,000	30,000
154653	MC 4A Recyc Pump OVERHAUL 2018	125,000					125,000
154654	MC 4B CTP OVERHAUL 2020			30,000	119,745		149,745
154655	MC 4B Recyc Pump OVERHAUL 2018	125,000					125,000
154656	MC 4C Recyc Pump OVERHAUL 2019		122,478				122,478
154657	MC 4D Recyc Pump OVERHAUL 2019		122,478				122,478
154658	MC 4E Recyc Pump OVERHAUL 2022			120,796			120,796
154659	MC3 TDBFP OVERHAUL 2019		220,586				220,586
154660	MC4 TDBFP OVERHAUL 2022					222,643	222,643
154678	MC1 Warm-up Gas Gun Valve	65,000	55,000				120,000
154679	MC2 Warm-up Gas Gun Valve	55,000					55,000
154701	TC1 SSC CHAIN REPL				222,376		222,376

Project	Description	2018	2019	2020	2021	2022	Grand Total
154702	TC1 SSC FLIGHT REPL				202,888		202,888
154703	TC1 SSC TILE REPL				222,376		222,376
154704	TC1 BACKPASS FRONT WALL		491,730				491,730
154705	TC1 RADIANT RH TUBE REPL				364,548		364,548
154706	TC1 RHO TERMINAL TUBE REPL				287,843		287,843
154707	TC1 LOWER FURNACE WW REPL			170,910	570,685		741,595
154708	TC1 LOWER FURNACE WW REPL-	178,410	572,685				751,095
154711LGE	TC2 ACOUSTIC MONITORS-	19,084					19,084
154713LGE	TC2 HYDROJET STRAINER-	10,444					10,444
154717LGE	TC2 CAGE RING HADER MAIN-	30,335					30,335
154719LGE	TC2 REPL SB CONTROL VLV-	31,048					31,048
154721LGE	TC2 ID FAN SEAL AIR UPG-	42,372					42,372
154729LGE	TC COAL CONVEYOR VFD UPGD-	46,387	46,573	47,103			140,063
154731LGE	TC COAL CRUSHER BIN TOP-	23,193					23,193
154733LGE	TC2 BATTERY UPGD-	42,372					42,372
154738	TC1 BATTERY REPLACEMENTS			170,910	170,910		341,820
154741LGE	TC SERVICE WATER PUMP OH-			30,402		32,254	62,657
154743	TC1 COOLING TOWER PUMP OH		97,444		103,379		200,822
154744LGE	TC2 COOLING TOWER PUMP OH-			97,444		103,379	200,822
154747LGE	TC2 WESP WATER DIVERT-					119,505	119,505
154749LGE	TC2 GAS SCANNER UPGD-	33,898					33,898
154751LGE	TC LIMESTONE PREP CHUTE REPL-	34,790					34,790
154753	TC VEHICLES	71,364	69,564	68,364	68,364	68,364	346,020
154757LGE	TC SWP RECIRC VLV-	50,984					50,984
154759LGE	TC LED LIGHTING-	133,808	134,345	135,989	284,340		688,481
154761	TC1 BOILER ROOF EXHAUSTERS	53,523	53,738	54,396	56,028		217,685
154762LGE	TC HVAC UPGD	26,762	26,869	27,197	28,014	28,854	137,697
154763LGE	TC2 COMMON WASTE SUMP UPG-	16,949	16,521				33,470
154765	TC1 SDRS SUMP UPG					85,455	85,455
154769LGE	TC TRANSFORMER RELAY UPG-		67,825				67,825
154773LGE	TC2 TURBINE OIL FILTER UPG-	27,118	8,261				35,379
154786LGE	TC2 COND POLISHER RESIN UPG-	41,525					41,525
154790LGE	TC CT CEMS REPL-	39,193	76,783				115,976
154792LGE	TC CT WAREHOUSE-		39,420	77,479			116,899
154796LGE	TC CT SPARE TURBINE ROTOR-				6,558,265		6,558,265
154805LGE	TC LBU CLAMSHELL REPL-	58,743					58,743
154810LGE	TC CITY WATER LOOP TIE-	23,193	22,608				45,802
154829	CR7 NGCC CI (2021)				9,372,375		9,372,375
154831	CR7 UV LIGHTING		100,000				100,000
154833	CR7 EQ OVERHAUL	204,500	556,500	562,500	134,000	300,000	1,757,500
154835	PR13 GAS HEATER	105,000					105,000
154838	PR12 H2 Cooler		48,739				48,739
154839	PR13 H2 COOLER		97,471				97,471
154841	OF MAIN SUMP PUMP			33,529			33,529
155075LGE	TC2 BIASING DAMPER UPG-	38,135					38,135
155077LGE	TC INSIGHT CM VIB MONITOR-	22,301	21,739	21,364	21,364	21,364	108,131
155113	GS Gen Eng Relay Standard					48,840	48,840
155115	GS Gen Eng Bushing Monitor	38,295					38,295
155117	GS Gen Eng Cont DGA	25,530					25,530
155119	GS GenEng Discharge Monitor	31,913					31,913
155120	GS GenEng GIC Monitor	21,275					21,275
155121	GS GenEng SP Relays	23,000					23,000
155122	GS GenEng LFGFI					81,400	81,400
155123	GS GenEng Thermal Monitor	19,148					19,148
155124	GS GenEng MHM Software		37,000				37,000
155125	GS GenEng MetLab Equip				4,884		4,884
155126	GS GenEng Vibration Monitor	17,020			122,100		139,120
155127	GS GenEng Tsfrmer Protection		82,880	81,400	81,400	81,400	327,080
155176	GS GenEng Insight CM-LGE	17,802					17,802
155372LGE	TC2 ABB BREAKER UPG-	124,596					124,596
155396	MC1 Air Heater Baskets 2019	630,000	861,172				1,491,172
155418	MC3 Boiler Extended Arch Inst		2,055,000				2,055,000
155419	MC4 Boiler Extended Arch Inst					1,500,000	1,500,000
155443LGE	TC F COAL CONV GALLERY REBLD-	92,773	424,086	420,966			937,825
155516LGE	TC CCRT SPARES-	556,639					556,639
155558LGE	TC2 BOILER WATER WALL 2020-			325,035			325,035
155560LGE	TC2 BOILER WATER WALL 2021-				319,453		319,453
155562LGE	TC2 BOILER WATER WALL 2022-					328,988	328,988
155600	TC1 EXP JOINTS 2021				353,356		353,356
155617	TC1 TDBFP OVERHAUL 2021				135,556		135,556
155618	TC1 STRUCTURAL BYPASS 2021				217,625		217,625
155621	TC1 COAL CONDUITS 2021				131,749		131,749
155625	TC1 DIVISION PANEL RPL 2023					256,365	256,365
155627LGE	TC2 MS TURBINE BYP VLV 2021-				43,785		43,785
155643LGE	TC2 CONVERT DOORS 2022-					21,649	21,649
155647LGE	TC2 HRH TURBINE BP VLV 2022-					58,162	58,162
155651LGE	TC2 EXPANSION JOINTS 2020-			81,182			81,182
155653LGE	TC2 EXPANSION JOINTS 2022-					81,182	81,182
155659LGE	TC2 BURNER B,E ROWS 2020-			47,370			47,370

Project	Description	2018	2019	2020	2021	2022	Grand Total
155667	TC1 SH DMW REPL 2021				226,456		226,456
155923LGE	BRCT5 Inlet Coils Repl LGE	116,600					116,600
161002LGE	TC2 TURBINE RESEAL HP-IP PATH	133,303					133,303
161003LGE	TC2 TURBINE REPL HP INLET SNS	48,138					48,138
161004LGE	TC2 TURBINE RESEAL LPA & LPB		133,303				133,303
165000	TC1 FRONT LOWER SLOPE				721,595		721,595
165001	TC1 DIVISION PANEL REPLAC			128,183	600,497		728,680
LTPGENLG	Other LTP Gen Projects LGE	112,500	112,500	112,500	112,500	112,500	562,500
127095	Ohio Falls Redev. #8	1,270,000					1,270,000
132875	Canal Demolition	1,810,000	1,340,000	1,710,000	5,005,169		9,865,169
133671	EFFLUENT WATER STUDY-MC	1,004,000					1,004,000
133679	EFFLUENT WATER STUDY-TC LGE	518,700					518,700
134898	PE Vehicle Purchases	200,000					200,000
137503	CR AP & LF Capping & Closure	1,110,000					1,110,000
148469	CR DEMO - PE ONLY	16,995,203	14,101,001				31,096,204
148833	MC ASH POND CCR	6,515,000	9,174,992	9,978,014	12,945,007		38,613,013
148834	MC CLEARWELL CCR	2,456,000					2,456,000
148836	MC CONSTRUCT CCR	2,881,000					2,881,000
148837	MC DSP CCR	100,000	3,809,000				3,909,000
148841	TC AP LGE CCR	2,380,560	4,648,800	3,439,800	3,907,800	3,024,450	17,401,410
148843	TC GYP LGE CCR	58,500	2,457,000	2,457,000	3,097,380		8,069,880
151115	TC CCRT - BOTTOM ASH LGE	2,867,000					2,867,000
151116	TC CCRT - FLY ASH LGE	8,755,227					8,755,227
151117	TC CCRT - GYPSUM LGE	10,655,073					10,655,073
151118	TC CCRT - TRANSPORT LGE	10,042,500	17,523,480				27,565,980
151119	TC CCRT - LANDFILL LGE	15,128,100	6,727,500	6,142,500			27,998,100
152330	MC Gypsum Dewatering Non-ECR	49,861,000	7,300,000				57,161,000
152381	MC Process Water	89,106,002	21,485,001	8,678,000			119,269,002
152384	TC LGE Process Water	21,960,580	7,824,772				29,785,353
152901	MC CCR New Construction	100,000	4,360,000	4,485,000			8,945,000
152966	ELG MC ECR					8,857,000	8,857,000
152967	ELG TC LGE ECR					2,619,240	2,619,240
155513	TC CCR New Const Proces Pd LGE	819,000	2,106,000				2,925,000
155705	OHIO FALLS U7 REWIND	6,200,000					6,200,000
131853	CIP-LGE-2018	334,082					334,082
131855	CIP-LGE-2019		328,709				328,709
131858	CIP-LGE-2020			366,300			366,300
131881	Control House Upgrds-LGE-2020			2,143,000			2,143,000
134195	DSP RUSSELL CRNR SUB					513,583	513,583
134198	CR CNL-DLPRK 69KV	200,333	2,663,014	637,086			3,500,432
134203	DSP FEGENBUSH TAP					435,000	435,000
134204	DSP MT WSHNGTN SUB		132,210	245,083			377,293
134238	DSP LIME KILN SUBSTATION			320,683	526,561		847,244
135403	TEP MUD LN-SMYRNA 69KV	13,012	487,000				500,013
137482	Control House Upgrds-LGE-2021				2,000,000		2,000,000
137483	Control House Upgrds-LGE-2022					2,000,000	2,000,000
137572	ROUTINE EMS-LGE 2018	6,250					6,250
137763	RIVER RD HWY RELO				1,319,265		1,319,265
139691	Test Lab Equipment-2018-LGE	68,316					68,316
140058	EMS DBASE EXPANSION-LGE-2018	96,000					96,000
140072	DIGITAL EMS COM CHNLS-LGE-2018	95,991					95,991
140074	DIGITAL EMS COM CHNLS-LGE-2019		38,589				38,589
140087	LITE UPGRDE EMS SWARE LGE-2019		28,319				28,319
140095	SIMP CC V_WALL RPLC-LGE-2020			680,000			680,000
140099	EMS OPERATOR MONITORS-LGE-2019		15,245				15,245
140112	ROUTINE EMS-LGE 2019		6,000				6,000
140224	FULL UPGRD EMS SWARE-LGE-2018	83,167					83,167
140440	TEP NORTH TAP-SO PARK 69kV	158,009	3,009,000				3,167,009
144368	CIP-LGE-2021				366,300		366,300
144370	CIP-LGE-2022					333,000	333,000
146709	OUTERLOOP LANDFILL RELO	-					-
147230	TEP-Watterson Term Eqp	25,000					25,000
147527	REL Locust Sub Switch MOS	465,499					465,499
147735	FULL UPGRD EMS SWARE-LGE-2020		31,000	134,948			165,948
147745	SIMP V_WALL C_RPLC-LGE 2019		149,000				149,000
147766	EMS DBASE EXPANSION-LGE-2019		33,044				33,044
147770	EMS DBASE EXPANSION-LGE-2020			33,790			33,790
147774	DIGITAL EMS COM CHNLS-LGE-2020			39,000			39,000
147791	EMS APP ENHANCEMENTS-LGE-2018	19,000					19,000
147795	EMS APP ENHANCEMENTS-LGE-2019		19,000				19,000
147798	EMS APP ENHANCEMENTS-LGE-2020			19,000			19,000
147800	RTU-IP TRAFFIC TO EMS-LGE-2018	59,211					59,211
147802	RTU-IP TRAFFIC TO EMS-LGE-2019		59,114				59,114
147804	RTU-IP TRAFFIC TO EMS-LGE-2020			64,770			64,770
147806	ROUTINE EMS-LGE 2020			6,000			6,000
147819	SPIR Project LGE 2016-2025	363,000	399,300	439,230	483,153	531,468	2,216,151
148059	LITE UPGRDE EMS SWARE-LGE-2021				34,000		34,000
148066	FULL UPGRD EMS SWARE-LGE-2022				38,000	101,000	139,000
148070	RTU-IP TRAFFIC TO EMS-LGE-2021				63,000		63,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
148072	RTU-IP TRAFFIC TO EMS-LGE-2022					63,000	63,000
148166	EMS D-BASE EXPANSION-LGE-2021				96,000		96,000
148174	EMS DBASE EXPANSION-LGE-2022					34,526	34,526
148186	DIGITAL EMS COM CHNLS-LGE-2021				96,000		96,000
148188	DIGITAL EMS COM CHNLS-LGE-2022					39,000	39,000
148200	BACKUP CC V_WALL RPLC-LGE-2021				19,200		19,200
148244	EMS OPERATOR MONITORS-LGE-2022					15,000	15,000
148252	EMS APP ENHANCEMENTS-LGE-2021				19,000		19,000
148255	EMS APP ENHANCEMENTS-LGE-2022					19,000	19,000
148296	ROUTINE EMS-LGE-2021				6,000		6,000
148299	ROUTINE EMS-LGE-2022					6,000	6,000
148821	SR Floyd-Seminole 69kV	200,044	1,300,228				1,500,272
148822	CR Olin-Tip Top 69kV		200,001	4,645,000	5,665,000		10,510,001
148850	CR Hrds Crk-Hrmny Ldg 69kV Rbd			297,991	2,381,000	2,976,000	5,654,991
149140	TEP-Blue Lick Xfrmr Rpl					-	-
149679	Middletown CIP Security Upgrds	1,518,000					1,518,000
151466	MT 345 Bus Redundancy	152,760	336,283				489,043
151750	Spare 345/138 Transformer	2,168,766					2,168,766
151752	DSP Plainview 138kV UPG	139,951	309,929				449,879
151755	LGE Arrester Replacements	75,000	89,525	188,001	217,999		570,525
151756	LGE Breaker Replacements		460,000	2,800,001	2,800,000	2,800,000	8,860,001
151757	LGE Fence Replacements	816,000	816,001	816,036	816,046	400,000	3,664,083
151758	DSP Mud Lane-Smyrna 69kV		563,301	869,663			1,432,964
151760	LGE Transformer Bushing Rpl		170,530				170,530
151768	DSP Crestwood 138kV Radial			175,136	325,073		500,209
151769	DSP Breckenridge-Ethel Radial			673,373			673,373
151770	DSP Tucker Station				264,912	374,608	639,520
152108	REL-MT-TC Sw-CF Brkr Add	756,565					756,565
152109	REL-Smyrna 604 Brkr Add	793,228					793,228
152123	REL-Harmony Landing Auto	210,969					210,969
152178	PBR-Shively 69kV Brkr Rpl	93,152					93,152
152224	Clifty Creek DL1/DL2 Brkr Rpl	100,000	1,099,999				1,199,999
152226	Middletown (5) 345kV Brkr Rpl	2,149,999					2,149,999
152614	LGE Station Grounding	74,998	50,000	232,899	258,061		615,958
152615	LGE Spare 345/138 XTR		75,000	2,290,000	835,000		3,200,000
152618	LGE Spare 138/69 XTR	693,251					693,251
152621	LGE Cap and Pin Rpl		100,000	232,900	258,060	250,000	840,960
152632	LGE Coupling Capacitor Rpl			200,000	200,000		400,000
152639	LGE Online Monitoring Equip	255,001	255,000	254,998	255,000	255,000	1,274,998
152642	LGE Resiliency Upgrades		255,000	235,000	273,000		763,000
152710	CR Penal Farm-Skylight		199,979	4,500,001	2,800,000		7,499,980
152711	CR Skylight-Harmony Landing		200,000	1,200,000	2,600,001		4,000,001
153373	Battery Replacements - LGE	153,092	153,092	153,092	153,000	153,000	765,276
153374	DFR Installations - LGE			315,789	315,789		631,578
153375	PLC Replacements - LGE			84,219	84,217	83,000	251,436
154591	TC 345kV 4511 Breaker	250,000					250,000
154843	Trimble Co TCT 7-10	2,442,604					2,442,604
L5-2018	Relocations T Lines LGE 2018	52,046					52,046
L8-2018	Storm Damage T-Line LGE 2018	176,513					176,513
L8-2019	Storm Damage T-Line LGE 2019		181,436				181,436
L8-2020	Storm Damage T-Line LGE 2020			185,655			185,655
L8-2021	Storm Damage T-Line LGE 2021				190,578		190,578
L8-2022	Storm Damage T-Line LGE 2022					195,551	195,551
L9-2018	Priority Repl T-Lines LGE 2018	576,000					576,000
L9-2019	Priority Repl T-Lines LGE 2019		2,112,002				2,112,002
L9-2020	Priority Repl T-Lines LGE 2020			2,111,774			2,111,774
L9-2021	Priority Repl T-Lines LGE 2021				2,112,256		2,112,256
L9-2022	Priority Repl T-Lines LGE 2022					2,112,041	2,112,041
LARM-2020	Priority Repl X-Arms LGE 2020			144,000			144,000
LARM-2021	Priority Repl X-Arms LGE 2021				144,000		144,000
LARM-2022	Priority Repl X-Arms LGE 2022					144,029	144,029
LBRFAIL18	LGE-Brkr Fail-2018	450,000					450,000
LBRFAIL19	LGE-Brkr Fail-2019		465,360				465,360
LBRFAIL20	LGE-Brkr Fail-2020			450,000			450,000
LBRFAIL21	LGE-Brkr Fail-2021				450,000		450,000
LBRFAIL22	LGE-Brkr Fail-2022					450,000	450,000
LI-000037	PR CR Switching-Shively		1,100,000				1,100,000
LI-000054	MOS Lebanon J 423-805-815-825	100,000					100,000
LI-000056	MOS Cedar Grove			100,000			100,000
LI-000057	REL Jeffersontown ALT 4	100,000	1,000,000				1,100,000
LI-000062	REL Mt. Washington RECC		150,000				150,000
LI-000087	TEP Ashbottom-Cane Rn Sw					62,500	62,500
LI-000088	TEP Ford-Freys Hill			50,000	1,950,000		2,000,000
LI-000090	TEP Skylight-Harmony Ldg	38,000	1,462,000				1,500,000
LI-000108	LaGrange Road Relo	243,719					243,719
LINS-2018	Priority Repl Insltrs LGE 2018	81,000					81,000
LINS-2019	Priority Repl Insltrs LGE 2019		163,000				163,000
LINS-2020	Priority Repl Insltrs LGE 2020			163,000			163,000
LINS-2021	Priority Repl Insltrs LGE 2021				163,000		163,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
LINS-2022	Priority Repl Insltrs LGE 2022					122,057	122,057
LOTFAIL18	LGE-OtherFail-2018	550,001					550,001
LOTFAIL19	LGE-OtherFail-2019		550,000				550,000
LOTFAIL20	LGE-OtherFail-2020			549,999			549,999
LOTFAIL21	LGE-OtherFail-2021				549,999		549,999
LOTFAIL22	LGE-OtherFail-2022					550,000	550,000
LOTH-2018	Priority Repl Other LGE 2018	150,000					150,000
LOTH-2019	Priority Repl Other LGE 2019		1,001,000				1,001,000
LOTH-2020	Priority Repl Other LGE 2020			1,128,674			1,128,674
LOTH-2021	Priority Repl Other LGE 2021				1,156,949		1,156,949
LOTH-2022	Priority Repl Other LGE 2022					1,078,223	1,078,223
LOTPR18	LG&E Other Prot Blanket 2018	14,392					14,392
LOTPR19	LG&E Other Prot Blanket 2019		38,945				38,945
LOTPR20	LG&E Other Prot Blanket 2020			39,939			39,939
LOTPR21	LG&E Other Prot Blanket 2021				178,619		178,619
LOTPR22	LG&E Other Prot Blanket 2022					670,000	670,000
LRELAY-18	Relay Replacements-LG&E-2018	(2)					(2)
LRELAY-20	Relay Replacements-LG&E-2020			2,180,000			2,180,000
LRELAY-21	Relay Replacements-LG&E-2021				2,180,000		2,180,000
LRELAY-22	Relay Replacements-LG&E-2022					2,180,000	2,180,000
LRTU-20	LGE RTU Replacements-20			1,080,000			1,080,000
LRTU-21	LGE RTU Replacements-21				1,075,000		1,075,000
LRTU-22	LGE RTU Replacements-22					1,075,000	1,075,000
LTFFAIL18	LGE-Xfrmr Fail-2018	1,500,000					1,500,000
LTFFAIL19	LGE-Xfrmr Fail-2019		1,500,000				1,500,000
LTFFAIL20	LGE-Xfrmr Fail-2020			1,500,000			1,500,000
LTFFAIL21	LGE-Xfrmr Fail-2021				1,500,000		1,500,000
LTFFAIL22	LGE-Xfrmr Fail-2022					1,500,000	1,500,000
SU-000005	PBR-Hurstbrn 1 138kV BKR Rpl	300,000					300,000
SU-000007	PBR-Watterson (3) 138kV BKRRpl	1,089,593					1,089,593
SU-000008	PBR-Aiken(1) 69kV BKR Rpl	370,000					370,000
SU-000017	PAR-Collins Arrsters 6684,6685	75,000					75,000
SU-000029	PGG-Clifton GG Audit/Rmdiation	200,000					200,000
SU-000032	PGG-Madison GG Audit/Rmdiation		200,000				200,000
SU-000034	PGG-Shively GG Audit/Rmdiation	250,000					250,000
SU-000041	PBR-Algonquin (1) 138kV BKR	50,000	200,000				250,000
SU-000045	PBR-Jeffersontown(1) 138kV BKR	50,000	200,000				250,000
SU-000046	PBR-Tip Top (2) 138kV BKR		500,000				500,000
SU-000049	PBR-Kenwood(3) 69kV BKR		650,000				650,000
SU-000051	PBR-Magazine (2) 69kV BKR	75,000	225,000				300,000
SU-000054	PBR-PaddysRun (3) 69kV BKR	100,000	375,000				475,000
SU-000057	PRLY-Cmpgrnd - PaddysRun(3803)	240,000					240,000
SU-000059	PRLY-Clay LGE -Madison (6627)	240,000					240,000
SU-000060	PRLY-Ashbottom - S Park (6639)	240,000					240,000
SU-000061	PRLY-Aiken-Middletown (6657)	240,000					240,000
SU-000062	PRLY-Nachand-Wattrson (6667)	240,000					240,000
SU-000063	PRLY-Grady-Paddys Run (6633)	240,000	240,000				480,000
SU-000072	PRLY-Canal - Del Park (6616)		240,000				240,000
SU-000073	PRLY-Canal -FallsStation(6608)		240,000				240,000
SU-000074	PRLY-Canal -FallsStation(6611)		240,000				240,000
SU-000075	PRLY-Canal - Magazine (6612)		240,000				240,000
SU-000076	PRLY-Algonquin-PadRun (6632)		240,000				240,000
SU-000077	PRLY-Aiken-Oxmoor (6650)		240,000				240,000
SU-000078	PRLY-Algonquin-Magzn (6646)		240,000				240,000
SU-000095	PIN Trimble Co TCT SW (4515)	120,000					120,000
SU-000102	PBR Ashbttm-Cane Rn Swtch 3833		240,000				240,000
SU-000103	PBR Bcknr-Trmble Co Swtch 4544	240,000					240,000
SU-000125	PDFR Waterside West	150,000					150,000
SU-000126	PDFR Mill Creek Switching	150,000					150,000
SU-000127	PDFR Beargrass	150,000					150,000
SU-000131	PR Flyd - Lcst - Simnole 6647		240,000				240,000
SU-000132	PR Ashbottom - Kenwood (6649)		240,000				240,000
SU-000133	PR Applnc Prk-Ash Bottom 3836		240,000				240,000
SU-000134	PR Beargrass-Lyndon South 3871		240,000				240,000
SU-000135	PR Lyndon So-Middletown 6652		240,000				240,000
SU-000136	PR Fern Vlly-Grade Ln 3835		240,000				240,000
SU-000137	PR Breckenridge-Ethel (3872)		240,000				240,000
SU-000138	PR Buckner-Mddltwn 345 4543	240,000					240,000
SU-000141	PR Clifton-Hillcrest (6628)		240,000				240,000
SU-000142	PR Ford-Freys Hill (6659)		240,000				240,000
SU-000157	PRTU BLUE LICK	150,000					150,000
SU-000158	PRTU MUD LANE	150,000					150,000
SU-000159	PRTU OXMOOR	150,000					150,000
SU-000160	PRTU ALGONQUIN	150,000					150,000
SU-000161	PRTU CENTERFIELD	150,000					150,000
SU-000162	PRTU PADDYS WEST	150,000					150,000
SU-000171	PRTU FARNSLEY		150,000				150,000
SU-000172	PRTU SEMINOLE		150,000				150,000
SU-000173	PRTU FERN VALLEY		150,000				150,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
SU-000174	PRTU ETHEL		150,000				150,000
SU-000175	PRTU LYNDON SOUTH		150,000				150,000
SU-000261	REL Jeffersontown ALT 4 SU		1,449,960				1,449,960
SU-000262	PBR-Ashbottom (4) 138kV BKR	572,682					572,682
SU-000263	PIN-Breckenridge 69KV+	240,000					240,000
SU-000264	PIN-Ethel 69kV+	289,867					289,867
SU-000265	PIN-Seminole 69 kV+	240,000					240,000
SU-000266	PIN-Algonquin 69KV	75,000	174,960				249,960
SU-000267	TEP-Skylight 69kV Capacitor	537,500					537,500
SU-000268	TEP-Wttrsn-Jffrsn 138kV Trm Eq	75,000					75,000
SU-000269	PBR-Taylor (2) 69kV BKR+		300,000				300,000
SU-000270	PGG-Clay LG&E GG		249,960				249,960
SU-000271	PGG-Seminole GG		249,960				249,960
SU-000272	PIN-Fern Valley 138-69 +		500,040				500,040
SU-000273	RSC-Kenzig Road Security Upgrd		200,040	1,179,960			1,380,000
SU-000274	PDFR Tip Top		150,000				150,000
SU-000275	PDFR CRS		150,000				150,000
SU-000276	RSC-Millcreek Security Upgrds			350,040	2,649,960		3,000,000
SU-000278	PIN-Lyndon South 138-69+	125,040	500,040				625,080
SU-000279	PDFR Middletown		150,000				150,000
SU-000280	PDFR Ethel		150,000				150,000
SU-000292	REL-Centerfield DFR		222,000				222,000
00002SECL	LG&E SECURITY EQUIPMENT 2022					165,051	165,051
00004FACL	LGE ELECTRICAL & LIGHTING 2021				153,000		153,000
00006FACL	LGE ELECTRICAL & LIGHTING 2022					156,996	156,996
00009FACL	FAC & SITE IMPROVE LGE 2021				4,175,004		4,175,004
00011FACL	FAC & SITE IMPROVE LGE 2022					1,716,996	1,716,996
00015FACL	AOC PARKING LOT IMPROVEMENTS			350,000			350,000
00026FACL	AOC MAIN HALLWAY & BREAKROOM		175,000				175,000
00027FACL	AOC MEN/WOMENS LOCKER ROOM		300,354				300,354
00028FACL	AOC ASSEMBLY ROOM RENOVATION		125,000				125,000
00029FACL	AOC SPACE EXPANSION	650,000					650,000
00030FACL	AOC FAÇADE RESTORATION	83,000					83,000
00031FACL	EOC SPACE EXPANSION	310,000					310,000
00032FACL	LGE CTR FITNESS CTR FLOOR LGE	13,800					13,800
00034FACL	BOC 1ST FLOOR RENOVATION LGE		885,000				885,000
00035FACL	SSC ENGINEERING CTR OF EXCEL		2,706,000	8,316,000	3,577,940		14,599,940
00036FACL	SSC ROOF REPLACEMENT		100,000				100,000
00039FACL	LGE CTR 12TH FLOOR KITCHEN LGE	23,000					23,000
00040FACL	BOC GUARDSHACK	70,000					70,000
00041FACL	RIVERPORT ROOF REPLACEMENT				4,600,000		4,600,000
00042FACL	REPL FAILED EQUIP LGE 2021				110,004		110,004
00044FACL	REPL FAILED EQUIP LGE 2022					113,004	113,004
00046FACL	FURN & EQUIP LGE 2021				470,004		470,004
00048FACL	FURN & EQUIP LGE 2022					482,004	482,004
00052FACL	BOC AHU-4 BOC-2 AHU RM	125,000					125,000
00053FACL	BOC AHU-7 BOC-LL MAINT AHU RM		129,000				129,000
00054FACL	BOC AHU-8 BOC-LL PSRT AHU RM		129,035				129,035
00056FACL	LGE CTR 2 CARPET REPL LGE		23,460				23,460
00065FACL	GAS & EL SAFETY-TRAIN BLDG EOC	1,685,000	815,000				2,500,000
00066FACL	BOC DCC TO SWING SPACE LGE		885,041				885,041
00067FACL	BOC ANNEX LGE	888,238					888,238
00073FACL	BOC MAIN BLDG RENOVATION LGE		1,206,556				1,206,556
0050FACIL	SIMPSON UPS BATTERY STR I L			90,000			90,000
0050FACTL	SIMPSON UPS BATTERY STRING			56,000			56,000
0064FACIL	SIMP SWITCHGEAR UPG IT L		24,960				24,960
0064FACTL	SIMP SWITCHGEAR UPG TR L		15,600				15,600
138439	DLC - LG&E Electric	900,551					900,551
139065	LGE CTR REMODEL REMOVAL	50,000	25,000				75,000
141392	LGE FURNITURE PROJ	255,000	128,000				383,000
141583	Meter Shop 2018 LG&E Electric	82,080					82,080
141618	Meter Shop 2019 LG&E Electric		108,440				108,440
141620	Meter Shop 2020 LG&E Electric			108,440			108,440
142367	Retail Hardware LG&E 2018	110,000					110,000
145021	LGE SECURITY EQUIPMENT 2018	165,000					165,000
145027	LGE SECURITY EQUIPMENT 2019		165,000				165,000
145087	Retail Hardware LG&E 2019		112,000				112,000
145404	Adv Meter Sys LG&E 2015	218,373	29,835	30,720	31,642	32,601	343,170
148022	RESTROOM RENOVATIONS-BOC	999,003					999,003
149165	LGE SECURITY EQUIPMENT 2020			165,000			165,000
149474	LGE REPL FAILED EQP 2018	104,000					104,000
149476	LGE FAC IMPROVEMENTS 2018	104,000					104,000
149481	Misc Retail Hardware 2020 LG&E			114,000			114,000
149484	LGE FURN & CHAIR 2018	124,000					124,000
149491	CARPET/FLOORING - LGE 2018	47,000					47,000
149493	AV EQUIPMENT - LGE 2018	152,000					152,000
149889	El Veh Chg Station LG&E 2015	84,807	29,336				114,143
152282	LGE SECURITY EQUIPMENT 2021				165,009		165,009
152372	REPL UPS CAPACITOR - LGE		75,000				75,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
152393	LGE ELECTRICAL & LIGHTING LTP			150,000			150,000
152769	LGE REPLACE FAILED EQ - 2019		106,000				106,000
152775	A/V EQUIPMENT - 2019		156,000				156,000
152778	LGE FACILITY IMPROVEMENTS-2019		106,000				106,000
152799	LG&E FURNITURE AND CHAIRS-2019		126,000				126,000
152805	LG&E CARPET/FLOORING-2019		48,000				48,000
153018	FAC & SITE IMPROVE LTP-LGE			642,000			642,000
153021	REPL FAILED EQUIP LTP-LGE			108,000			108,000
153024	FURN & EQUIP LTP-LGE			455,000			455,000
153047	Misc Retail Hardware 2021 LG&E				117,000	120,000	237,000
153065	Solar Projects - Community LGE	910,637	456,000	456,000	456,000	1,102,944	3,381,581
153071	Solar Projects - Business LGE	1,034,225	1,029,344	1,029,344	1,029,344	1,029,344	5,151,599
153098	Meter Shop 2021 LG&E Electric				108,440	108,440	216,880
153223	DLC LG&E Electric (Proposed)		1,048,271	873,061	873,061	873,061	3,667,454
153561	DCC ENHANCEMENT LGE	1,729,566	1,754,183				3,483,749
154108	REPLACE AIR HANDLERS BOC	125,000					125,000
155529	MV-90 Daily Read LG&E	426,830	373,000				799,830
CEMTR134	LGE Electric Meters - 001340	646,596	185,193	191,340	195,836	200,436	1,419,401
CGMTR134	LGE Gas Meters - 001340	4,016,556	4,311,598	2,897,203	2,969,017	3,044,930	17,239,303
159LGE16	Cascade Impl Gen Relays-LGE16	27,544					27,544
IT0001L	ABB Upgrade-LGE17	17,600					17,600
IT0003L	AIS Deciscion Trans-LGE17	132,000					132,000
IT0011L	Cascade Biennial Tech-LGE17	220,000					220,000
IT0017L	Commun Solar Implem-LGE17-18	22,000					22,000
IT0026L	Data Protection-LGE17-18	6,360					6,360
IT0041L	Gen Ldgr Acct Recon-LGE17-18			41,600	130,000		171,600
IT0045L	Intrusion Prevention-LGE17-18	365,601					365,601
IT0066L	NEC MW Rad Encrypt Card-LGE17	78,000					78,000
IT0075L	OpenText Transmission-LGE17-18	132,000					132,000
IT0076L	Oracle Financial Upgr-LGE17-18			1,612,001	2,028,001		3,640,001
IT0101L	Smallworld GIS Upgr-LGE17-19	1,320,000	440,000				1,760,000
IT0110L	Trans Cascade-Oracle-LGE17	33,000					33,000
IT0111L	Trans Vegetation Mgt-LGE17-18	88,000					88,000
IT0113CG	TC Plant Alt Transport-LGE17		200,000	100,000			300,000
IT0125L	NE KY Build Des&Yr 1/3-LG16-21	5,200	5,200	70,851	938,600		1,019,851
IT0135L	Strategic Sourcing-LGE17	16,960					16,960
IT0202L	Access Switch Rotation-LGE18	259,999					259,999
IT0203L	Aligne Upgrade-LGE18	44,000					44,000
IT0204L	Analog Sunset-LGE18	182,000					182,000
IT0205L	Avaya Release Upgr-LGE18	88,000					88,000
IT0206L	Bulk Power & Env Syst-LGE18	104,000					104,000
IT0207L	Cabling Server Connect-LGE18	23,400					23,400
IT0208L	Centrify Licensing-LGE18	10,400					10,400
IT0209L	CERUS IV-LGE18	208,000					208,000
IT0211L	CIP Compliance Tools Yr8-LGE18	130,000					130,000
IT0212L	Citrix XenDsktp Mjr Upg-LGE18	82,115					82,115
IT0213L	Citrix XenMobile Upgr-LGE18	36,918					36,918
IT0214L	Comp-Retire Topic 715-LGE18-19	260,000					260,000
IT0215L	CIP Compl Infrastrct Yr8-LGE18	260,000					260,000
IT0216L	Computer HW for LOB's-LGE18	192,400					192,400
IT0217L	Core Network Infrastr-LGE18	78,000					78,000
IT0219L	EE DSM Filing-LGE18-19	132,000	110,000				242,000
IT0220L	Elec Facility Enhance-LGE18-19	154,000					154,000
IT0221L	EMS CIP-LGE18	44,854					44,854
IT0222L	Endpoint Protection-LGE18	2,600					2,600
IT0223L	Enterp Data Domain Expan-LGE18	72,401					72,401
IT0224L	Exchange 20xx Upgrade-LGE18	124,800					124,800
IT0225L	FERC Form 1 Tool Repl-LGE18-19	260,000	264,104				524,104
IT0229L	Install Cooling-Simps-LGE18					52,000	52,000
IT0231L	IP Management-LGE18	182,000					182,000
IT0232CG	IRAS Enhancements-LGE18	475,000					475,000
IT0233CG	IRAS Intern Corrosion-LGE18-19	500,000	208,391				708,391
IT0234L	IT Security Infras-LGE18	39,012					39,012
IT0235L	ITSM CIP/AIM-LGE18	156,000	156,000				312,000
IT0236L	IVR - Major Upgrade-LGE18-19				264,000	440,000	704,000
IT0238L	Louisv Electrical Upgr-LGE18	26,000					26,000
IT0239L	Louis Racks and Furn-LGE18	13,000					13,000
IT0240L	Low Income Assist Portal-LGE18	22,000					22,000
IT0241L	Maximo Upgrade-LGE18-19	220,000	220,000				440,000
IT0242L	Megastar & DVM MW Repl-LGE18	288,900					288,900
IT0243L	Microsoft EA-LGE18	194,232					194,232
IT0244L	Microsoft Lic True-up-LGE18	78,000					78,000
IT0245L	Mbl & Wrkst Lic True-up-LGE18	39,520					39,520
IT0246L	Mobile Dispatch Enhance-LGE18		418,000				418,000
IT0247L	Mobile Infrastructure-LGE18	66,000					66,000
IT0248L	Mobile Radio-LGE18	104,000					104,000
IT0249L	Monitor Replacement-LGE18	55,120					55,120
IT0250L	MR Hardware-LGE18	22,000					22,000
IT0251L	Multi-Func Dev Ref-LGE18	20,800					20,800

Project	Description	2018	2019	2020	2021	2022	Grand Total
IT0252L	NAS Capacity Expan-LGE18	104,000					104,000
IT0253L	Network Access Infrast-LGE18	78,000					78,000
IT0254L	Network Access Gateways-LGE18	26,000					26,000
IT0255L	Network Management-LGE18	19,500					19,500
IT0256L	Network Test Equip-LGE18	65,000					65,000
IT0257L	Trans OATT Tool Upgr-LGE18		33,000				33,000
IT0258L	Open Text Data Automate-LGE18	55,000					55,000
IT0259L	OTN Ext Lex-Dix Ring-LGE18	452,400					452,400
IT0260L	Outside Cable Plant-LGE18	104,000					104,000
IT0261L	PeopleSoft Tools Enhance-LGE18	75,000					75,000
IT0262L	Personal Prod Refresh-LGE18	39,000					39,000
IT0263L	Purch/Rebuild Radio Site-LGE18	156,000					156,000
IT0264L	Rate Case 2018-LGE18-19	44,000	165,000				209,000
IT0265L	Replace Video Units-LGE18	52,000					52,000
IT0266L	Reporting/Business Intel-LGE18	88,000					88,000
IT0267L	Rev Collections Experian-LGE18	22,000					22,000
IT0268L	Rev Collect (Paymentus)-LGE18			22,000			22,000
IT0269L	Rev Collec (Transcentra)-LGE18	22,000					22,000
IT0270L	Rplce EMS Workstations-LGE18					66,000	66,000
IT0271L	SAN Capacity Expansion-LGE18	156,000					156,000
IT0272L	SAN Switch Refresh-LGE18	780,001					780,001
IT0273L	SAP CCS/CSS Releases-LGE18	330,001					330,001
IT0274L	SAP Roadmap Strategy -LGE18	220,000					220,000
IT0275L	Security Infrast Enhance-LGE18	52,000					52,000
IT0276L	Server Cap Expn & Reliab-LGE18	44,202					44,202
IT0277L	Server Hardware Refresh-LGE18	239,200					239,200
IT0278L	LogRhythm (CIP)-LGE18	33,800					33,800
IT0279L	LogRhythm (Corp)-LGE18	33,800					33,800
IT0280L	Simpsonville Elect Upgr-LGE18	26,000					26,000
IT0281L	Simpsonville Furn & Rack-LGE18	13,000					13,000
IT0282L	Site Security Improvemts-LGE18	26,000					26,000
IT0285CG	SynerGEE Gas Area Module-LGE18	150,000					150,000
IT0287L	Tech Refesh desk/lap-LGE18	1,355,617					1,355,617
IT0288L	Telecom Site Reno-LGE18	52,000					52,000
IT0289L	TOA-LGE18	44,000					44,000
IT0290L	Transmission Map-LGE18	44,000					44,000
IT0292L	UC4 Upgrade to V11-LGE18	26,000					26,000
IT0294L	Upgrade Quest Server-LGE18		78,000				78,000
IT0295L	Upgrade Vmware Infrast-LGE18	83,200					83,200
IT0296L	Video Streaming Appl Upg-LGE18	52,000					52,000
IT0297L	Phone Expan/Break Fix-LGE18	78,000					78,000
IT0298L	Wireless Buildout-LGE18	78,000					78,000
IT0299L	WMS Work Mgmt Sys Enh-LGE18	44,000					44,000
IT0300L	WMS Upgrade-LGE18-19	990,000					990,000
IT0301L	Rep ASTRO Spectra Yr 1/3-LGE18		494,000				494,000
IT0302L	Rep ASTRO Spectra Yr 2/3-LGE19			370,500			370,500
IT0303L	Rep ASTRO Spectra Yr 3/3-LGE20				370,500		370,500
IT0305L	Repl Quant Repeat Yr 1/2-LGE18		247,000				247,000
IT0306L	Repl Quantar Repeat 2/2-LGE19			494,000			494,000
IT0308L	Expense Reimb Replace-LGE18	260,000					260,000
IT0309L	Invoice Routing Automate-LGE18	260,000					260,000
IT0310L	PS Test Script Automate-LGE18	175,000					175,000
IT0311L	Mx Scheduler Program-LGE18	82,742					82,742
IT0312L	CyberArk Password Vault-LGE18	78,000					78,000
IT0313L	nMarket PJM Module Upgr-LGE18	52,000					52,000
IT0314L	HR Dashboard Enhance-LGE18	150,000					150,000
IT0315L	Mobile App/API Monitor-LGE18	130,000					130,000
IT0316L	PI Upgrade-LGE18	70,200					70,200
IT0317L	Safety Dashboard Enhance-LGE18	33,000					33,000
IT0318L	Mobile Safety App-LGE18	66,000					66,000
IT0319L	EMS Hardware Labor-LGE18	15,600					15,600
IT0320L	DB Refresh-LGE18	78,000					78,000
IT0321L	SCCM Upgrades-LGE18	41,600					41,600
IT0322L	Nxt Gen Radio System Des-LGE18	221,000					221,000
IT0324L	PowerPlan Lease Mod Fin-LGE18	26,000					26,000
IT0325L	Windows 10 Upgrade-LGE18	189,802					189,802
IT0326L	Office 2016 Upgrade-LGE18	93,600					93,600
IT0327L	Work Safety Audit App-LGE18	33,000					33,000
IT0328L	BI Report Aligne Fuels-LGE18	44,000					44,000
IT0329L	Lockout/Tagout Replace-LGE18	880,000					880,000
IT0330L	ITSM Tools-LGE18	208,000					208,000
IT0331L	Rate Case Filing 2017-LGE18	44,000					44,000
IT0332L	OpenText Bill Integrity-LGE18	48,400					48,400
IT0333L	Cust Rel Mgmt Maj Accts-LGE18	66,000					66,000
IT0334L	My Account Enhancement-LGE18	110,000					110,000
IT0335L	iPad Refresh Project-LGE18	173,190					173,190
IT0336CG	GITT Plastic Services-LGE17/18	150,000					150,000
IT0337CG	Barcode Gas Mat Steel-LGE18	400,000					400,000
IT0338L	IVR Enhancements-LGE18	264,000					264,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
IT0339L	Upgrade PowerBase 8.x-LGE18	44,000					44,000
IT0340L	Repl Opentext AP (OTAP)-LGE18	208,000					208,000
IT0341L	FieldSmart View Replace-LGE18	220,000					220,000
IT0342L	Mob Dis Replace Elec OMS-LGE18	308,000					308,000
IT0343L	Sfty/Tec Trn Rec OpenTxt-LGE18	88,000					88,000
IT0344L	Budg Enh Mass All/IntCom-LGE18	117,000	62,400				179,400
IT0345L	Hyperion Upgrade-LKS18-LGE18	62,400					62,400
IT0346L	Cherwell Implementation-LGE18	156,000					156,000
IT0347L	OpenText for Tax Returns-LGE18	52,000					52,000
IT0348L	OpenText Cred/Cont Adm-LGE18	65,000					65,000
IT0349L	KY Containerized E-mail-LGE18	28,600					28,600
IT0350L	Busines Offices Kiosks-LGE18	55,000					55,000
IT0351L	Landlord Portal -LGE18	88,000					88,000
IT0352L	Exp/Repl Cust Comm Chan-LGE18	132,000					132,000
IT0403L	Access Switch Rotation-LGE19		260,000				260,000
IT0404L	Analog Sunset-LGE19		182,000				182,000
IT0407L	Bill Design Tool Upg-LGE19			88,000			88,000
IT0408L	Bulk Power & Env Systems-LGE19		104,000				104,000
IT0409L	Cabling Server Connect-LGE19		23,400				23,400
IT0410L	Centrify Licensing-LGE19		10,400				10,400
IT0412L	CIP Compl Tools - Year 9-LGE19		130,000				130,000
IT0413L	Compliance Infra Year 9-LGE19		260,000				260,000
IT0414L	Computer HW for LOB's-LGE19		192,400				192,400
IT0417L	Core Network Infra-LGE19		78,000				78,000
IT0418L	Corp Firewall Replace-LGE19-20		208,000	208,000			416,000
IT0419L	Corporate Web Redesign-LGE19			52,000			52,000
IT0421L	Damage Assess Enhance-LGE19		22,000				22,000
IT0422L	Data Domain Entrprs Ref-LGE19		312,000				312,000
IT0423L	DB Backup Storage Ref-LGE19	260,000					260,000
IT0424L	Design Tool Upgr-LGE19-20		439,999	110,000			550,000
IT0425L	EMS CIP-LGE19		44,880				44,880
IT0427L	Endpoint Protection-LGE19		2,600				2,600
IT0429L	FleetFocus/AVL Interface-LGE19		88,000				88,000
IT0430CG	Gas Facility Inspections-LGE19		200,000				200,000
IT0431CG	IRAS Enhancements-LGE19		200,000				200,000
IT0432L	IT Sec & IP Labs Enhance-LGE19		25,996				25,996
IT0433L	IT Security Infras Ref-LGE19		83,198				83,198
IT0434L	LOAD -vendor upgrade-LGE19		66,000				66,000
IT0435L	LOTO Tech Refresh-LGE19			110,000			110,000
IT0436L	Louisville Elec Upgrades-LGE19		26,000				26,000
IT0437L	Louisville Racks and Fur-LGE19		13,000				13,000
IT0438L	Maximo Licenses-LGE19		57,200				57,200
IT0439L	Microsoft EA-LGE19		200,052				200,052
IT0440L	Microsoft Lic True-up-LGE19		78,000				78,000
IT0441L	Mbl & Wrkst Lic True-up-LGE19		36,920				36,920
IT0442L	Mobile Intrastructure-LGE19		44,000				44,000
IT0443L	Mobile Radio-LGE19		104,000				104,000
IT0444L	Monitor Replacement-LGE19		55,120				55,120
IT0445L	MR Hardware-LGE19		22,000				22,000
IT0446L	Multi-Functional Devices-LGE19		20,800				20,800
IT0448L	Network Access Devices-LGE19		78,000				78,000
IT0449L	Network Access Gateways-LGE19		26,000				26,000
IT0450L	Network Management -LGE19		19,500				19,500
IT0451L	Network Test Equipment-LGE19		65,000				65,000
IT0452L	Oracle NMS Enhance-LGE19			220,000			220,000
IT0453L	OTN Extension EKY Ring-LGE19		728,000	457,600			1,185,600
IT0454L	Outside Cable Plant -LGE19		104,000				104,000
IT0456L	PeopleSoft Tools Enhance-LGE19		75,000				75,000
IT0457L	Personal Prod Growth-LGE19		104,000				104,000
IT0458L	PowerPlant Upgrade-LGE19-20		624,000	676,000			1,300,000
IT0459L	Purch/Rebuild Radio Site-LGE19		130,000				130,000
IT0460L	Rate Case 2019-LGE19		33,000				33,000
IT0461L	Report/Bus Intelligence-LGE19		88,000				88,000
IT0462L	SAN Capacity Expansion-LGE19		156,000				156,000
IT0464L	SAP Data Archiving-LGE16			110,000			110,000
IT0465L	SAP Roadmap Strategy -LGE19		44,000				44,000
IT0466L	Sec Infra Enhancement-LGE19		52,000				52,000
IT0467L	Server Capacity Expan-LGE19		44,202				44,202
IT0468L	Server Hardware Refresh-LGE19		218,400				218,400
IT0469L	LogRhythm (CIP)-LGE19		36,400				36,400
IT0470L	LogRhythm (Corp)-LGE19		36,400				36,400
IT0471L	Simpsonville Elec Upgr-LGE19		26,000				26,000
IT0472L	Simpsonville Furn & Rack-LGE19		13,000				13,000
IT0473L	Site Security Improve-LGE19		26,000				26,000
IT0475L	StackVision Upgrade-LGE19		88,000				88,000
IT0476L	Sys Mgmt SCCM Upgrade-LGE19-20		32,760	32,760			65,520
IT0477L	Tech Refesh desk/lap-LGE19		1,364,354				1,364,354
IT0479L	Telecom Site Renov-LGE19		62,400				62,400
IT0480L	Time and Labor Upgr-LGE19-20	754,000	806,000				1,560,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
IT0481L	TOA-LGE19		44,000				44,000
IT0482L	Treasury Mgmt Sys Repl-LGE19		312,000	312,000			624,000
IT0484L	UC&C/CUCM Major Upgrade-LGE19					156,000	156,000
IT0485L	Upgrade Vmware Infra-LGE19		88,400				88,400
IT0486L	Voice Infra Expansion-LGE19		78,000				78,000
IT0487L	VPN Appliance Upgrade-LGE19		104,000				104,000
IT0488L	Vulnerability Scanning-LGE19		104,000				104,000
IT0489L	Wireless Buildout-LGE19		117,000				117,000
IT0490L	Repl Simulca Infr Yr 1/2-LGE19		520,000				520,000
IT0491L	Repl Simulca Infr Yr 2/2-LGE20			520,000			520,000
IT0492L	Rate Making Application-LGE19		520,000				520,000
IT0493L	Tripwire Repl for LID-LGE19		416,000				416,000
IT0494L	VERBA Repl or Maj Upgrd-LGE19		104,000				104,000
IT0495L	Contractor Mgmt Upgrades-LGE19		88,000				88,000
IT0496L	ESP Virt Win Servers-LGE19		104,000				104,000
IT0497L	EACM Infrastructure Refr-LGE19		130,000				130,000
IT0498L	DB Refresh-LGE19		78,000				78,000
IT0499L	Windows 10 CBB upgrade-LGE19		208,001				208,001
IT0500L	SCCM Upgrades-LGE19		41,600				41,600
IT0501L	Ivanti AppSense Env Mgr -LGE19		54,597				54,597
IT0502L	XenDesktop Maj Upgr-LGE19		104,127				104,127
IT0503L	Int/DMZ Firewall Upgr -LGE19		260,000				260,000
IT0504L	Trans GIS Enhancements-LGE19		176,000				176,000
IT0505L	ITSM Tools-LGE19		156,000				156,000
IT0506L	Low Inc Asst Agency Prtl-LGE19		22,000				22,000
IT0507L	iPad Refresh Project-LGE19		58,659				58,659
IT0508L	SOA Middleware Upgrade-LGE19		78,000				78,000
IT0509L	Upgr OpenText Capt Cntr-LGE19		104,000				104,000
IT0510L	Smlwrld UpgRep EDO Telco-LGE19		440,000	1,672,000	880,000		2,992,001
IT0511L	Trans Lines Wrk Mgmt Upg-LGE19		220,000	286,000			506,000
IT0512L	DACS Repl Prov/Mon Sys-LGE19		65,000				65,000
IT0513L	DACS Equip Repl (Yr1of3)-LGE19		208,000				208,000
IT0514L	DACS Equip Repl (Yr2of3)-LGE20			208,000			208,000
IT0515L	DACS Equip Repl (Yr3of3)-LGE21				208,000		208,000
IT0516L	Exp/Repl Cust Comm Chan-LGE19		176,000				176,000
IT0517L	OpenText for Acct Recons-LGE19		78,000				78,000
IT0601L	Ventyx Upgrade-LGE20				264,000		264,000
IT0602L	Access Switch Rotation-LGE20			260,000			260,000
IT0603L	Aspct EWrkfc Scd App Upg-LGE20				66,000		66,000
IT0604L	Avaya-Route&Rpt Upg-LGE20-21		307,999	308,000			615,999
IT0606L	Bulk Power & Env Systems-LGE20			78,000			78,000
IT0607L	Cabling Server Connect-LGE20			23,400			23,400
IT0609L	Call Recording Upgr-LGE20-21			363,000	209,000		572,000
IT0610L	Centrify Licensing-LGE20			10,400			10,400
IT0612L	CIP Compl Tools - Yr 10-LGE20			130,001			130,001
IT0613L	Citrix XenDesk Maj Upgr-LGE20			82,115			82,115
IT0614L	Citrix XenMobile Upgrade-LGE20			36,918			36,918
IT0615L	CIP Compl Infra - Yr 10-LGE20			260,000			260,000
IT0616L	Computer HW for LOB's-LGE20			192,400			192,400
IT0618L	Constellation MW Rplmnt-LGE20			234,000			234,000
IT0619L	Core Network Infra-LGE20			78,000			78,000
IT0620L	DACS/SONET Repl Eng/Des-LGE18	208,000					208,000
IT0621L	EMS SEC Enhancements-LGE20			44,880			44,880
IT0622L	Endpoint Protect License-LGE20			2,600			2,600
IT0624CG	Gas Facility Inspections-LGE20			200,000			200,000
IT0625L	GIS Enhancements-LGE20-21			176,000			176,000
IT0626CG	IRAS Enhancements-LGE20			200,000			200,000
IT0627L	IT Sec Infrast Enhance-LGE20			39,006			39,006
IT0628L	ITSM Upgrade-LGE20			156,000			156,000
IT0630L	Lville Electrical Upgr-LGE20			26,000			26,000
IT0631L	Lville Racks and Furn-LGE20			13,000			13,000
IT0632L	Microsoft EA-LGE20			200,200			200,200
IT0633L	Microsoft Lic True-up-LGE20			78,000			78,000
IT0634L	Mbl & Wrkst Lic True-up-LGE20			39,000			39,000
IT0635L	Mobile Infrastructure-LGE20			44,000			44,000
IT0636L	Mobile Radio-LGE20			104,000			104,000
IT0637L	Monitor Replacement-LGE20			55,120			55,120
IT0638L	MR Hardware-LGE20			22,000			22,000
IT0639L	Multi-Fun Dev Grow&Ref - LGE20			156,000			156,000
IT0640L	MV90 replacement-LGE20			330,000			330,000
IT0642L	NAS Refresh-LGE20			624,000			624,000
IT0643L	NetScout Refresh-LGE20					468,000	468,000
IT0644L	Ntwrk Acc Dev&Site Infra-LGE20			78,000			78,000
IT0645L	Ntwrk Acc Dev & Gateways-LGE20			26,000			26,000
IT0646L	Network Management-LGE20			19,500			19,500
IT0647L	Network Test Equipment-LGE20			65,000			65,000
IT0648L	OTN Extension West KY-LGE20				392,600	392,600	785,200
IT0649L	Outside Cable Plant -LGE20			104,000			104,000
IT0650L	PeopleSoft Tools Enhance-LGE20			75,000			75,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
IT0651L	Pers Product Grow & Ref-LGE20			52,000			52,000
IT0652L	Purch/Rebld Radio Site-LGE20			130,000			130,000
IT0653L	Rate Case 2020-LGE20			11,000			11,000
IT0655L	Reporting / BI-LGE20			88,000			88,000
IT0656L	Router Upgrade Project-LGE20			416,000			416,000
IT0657L	SAN Capacity Expansion-LGE20			312,000			312,000
IT0658L	SAP CRM/ECC Enhancement-LGE20			220,001			220,001
IT0659L	SAP Roadmap Strategy -LGE20			440,001			440,001
IT0660L	Sec Infra Enhancements-LGE20			52,000			52,000
IT0661L	Ser Cap Expan and Rel-LGE20			44,202			44,202
IT0662L	Server Hardware Refresh-LGE20			467,480			467,480
IT0663L	SharePoint Upgrade-LGE20			156,000			156,000
IT0664L	LogRhythm (CIP)-LGE20			36,400			36,400
IT0665L	LogRhythm (Corp)-LGE20			36,400			36,400
IT0666L	Simpsonville Elect Upg-LGE20			26,000			26,000
IT0667L	Simpson Furn&Racks-LGE20			13,000			13,000
IT0668L	Site Security Improve-LGE20			26,000			26,000
IT0670L	Sys Lab software refresh-LGE20			110,000			110,000
IT0671L	Tech Refresh desk/lap-LGE20			1,362,912			1,362,912
IT0672L	Telecom Site Ren-LGE20			52,000			52,000
IT0673L	TOA Upgrade-LGE20			88,000			88,000
IT0675L	Truepoint MW Replacement-LGE20			182,000			182,000
IT0676L	UC4 Upgrade to V12-LGE20			26,000			26,000
IT0677L	Upgrade EMS Hardware-LGE20				22,000		22,000
IT0678L	Upgr Quest Content Srv-LGE20					78,000	78,000
IT0679L	Upgrade Vmware Infra-LGE20			93,600			93,600
IT0680L	Voice Infra Expansion-LGE20			78,000			78,000
IT0681L	Wireless Buildout-LGE20			26,000			26,000
IT0682L	SCADA Radio Refrsh Yr1/2-LGE20			74,100			74,100
IT0683L	SCADA Radio Refr Yr 2/2-LGE21				104,000		104,000
IT0685L	SCADA Radio Refr Yr 3of3-LGE22					78,000	78,000
IT0686L	Phone HW Refresh Yr 1/3-LGE20					273,000	273,000
IT0687L	EMC TLA Renewal-LGE20			2,340,000			2,340,000
IT0688L	BI Upgrade-LGE20			156,000			156,000
IT0689L	Safety Dashboard Enhance-LGE20			33,000			33,000
IT0690L	Aligne Upgrade-LGE20			88,000			88,000
IT0691L	Repl Modules OTN router-LGE20			130,000			130,000
IT0692L	CyberArk Hardware Refr-LGE20			26,000			26,000
IT0693L	DB Refresh-LGE20			78,000			78,000
IT0694L	Windows 10 CBB Upgrade-LGE20			208,001			208,001
IT0695L	SCCM Upgrades-LGE20			81,796			81,796
IT0696L	RSA Appliance Upgrade-LGE20			130,000			130,000
IT0697L	Replace ACS Servers-LGE20			26,000			26,000
IT0698L	Cane Run Replacement-LGE20			23,400			23,400
IT0699L	ESP Virt Mon App Svrs-LGE20			312,000			312,000
IT0700L	Trans GIS Enhancements-LGE20			132,000			132,000
IT0701L	Trans Lines Mobile Insp-LGE20			110,000			110,000
IT0702L	Rate Case Filing 2019-LGE20			55,000			55,000
IT0703L	Community Solar Enhance-LGE20			88,000			88,000
IT0704L	Low Inc Asst Agency Prtl-LGE20			22,000			22,000
IT0705L	iPad Refresh Project-LGE20			65,351			65,351
IT0706L	CyberArk Corp SW Upgr-LGE20			26,000			26,000
IT0707CG	GDO Mobile Disp Replace-LGE20			550,000			550,000
IT0708L	My Acct Replace/Enhance-LGE20			308,000	220,000		528,001
IT0709L	Cisco Dial Tone Call Ctr-LGE20			104,000			104,000
IT0801L	ABB Upgrade-LGE21					352,000	352,000
IT0802L	Access Switch Rotation-LGE21				378,301		378,301
IT0804L	Bulk Power & Environ Sys-LGE21				78,000		78,000
IT0805L	Cable for Server Connect-LGE21				23,400		23,400
IT0806L	Cascade Upgrade-LGE21					220,000	220,000
IT0807L	Centrify Licensing-LGE21				10,400		10,400
IT0808L	CERUS IV-LGE21				208,000		208,000
IT0810L	CIP Comp Tools - Year 11-LGE21				130,000		130,000
IT0811L	Complia Infra - Year 11-LGE21				260,000		260,000
IT0812L	Computer HW for LOB's-LGE21				192,400		192,400
IT0814L	Core Network Infra-LGE21				78,000		78,000
IT0816L	Design Tool Enhancements-LGE21				176,000		176,000
IT0818L	EMS Security Enhance-LGE21				44,880		44,880
IT0819L	Endpoint Protection Lic-LGE21				2,600		2,600
IT0820L	Enterpri Data Dom Expan-LGE21				72,401		72,401
IT0821L	External Outage Map Upgr-LGE21				110,000		110,000
IT0822L	FieldNet SoftwareUpgr-LGE21				121,000		121,000
IT0824CG	Gas Facility Inspections-LGE21				200,000		200,000
IT0825CG	IRAS Enhancements-LGE21				500,000		500,000
IT0826L	IT Sec Infra-Refresh-LGE21				83,198		83,198
IT0828L	Louisville Elect Upgr-LGE21				26,000		26,000
IT0829L	Louis Racks and Furn-LGE21				13,000		13,000
IT0831L	MicroSoft EA-LGE21				200,200		200,200
IT0832L	Microsoft Lic True-up-LGE21				78,000		78,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
IT0833L	Microsoft Office Upgrade-LGE21				143,000		143,000
IT0834L	Mob & Workst Lic True-Up-LGE21				34,840		34,840
IT0835L	Mobile Infrastructure-LGE21				44,000		44,000
IT0836L	Mobile Radio-LGE21				104,000		104,000
IT0837L	Monitor Replacement-LGE21				54,080		54,080
IT0838L	MFD Growth and Refresh-LGE21				234,000		234,000
IT0840L	Net Access Dev & Infrast-LGE21				78,000		78,000
IT0841L	Net Access Dev and Gate-LGE21				26,000		26,000
IT0842L	Network Management-LGE21				19,500		19,500
IT0843L	Network Test Equipment-LGE21				65,000		65,000
IT0844L	OATI web Accounting -LGE21					33,000	33,000
IT0845L	Oracle NMS Upg Out Mgmt-LGE21				550,005		550,005
IT0847L	Outside Cable Plant -LGE21				104,000		104,000
IT0848L	PeopleSo/PeopleTools Upg-LGE21				75,000		75,000
IT0849L	Person Produc Refresh-LGE21				39,000		39,000
IT0850L	Purch/Rebuild Radio Site-LGE21				130,000		130,000
IT0851L	Rate Case 2021-LGE21				22,000		22,000
IT0852L	Refr Videoconf Endpoints-LGE21				52,000		52,000
IT0853L	Replace Backup Infrastr-LGE21				132,000		132,000
IT0857L	Repl Oper Workstations-LGE21					66,000	66,000
IT0858L	Reporting / BI-LGE21				88,000		88,000
IT0861L	SAN Refresh-LGE21				560,560		560,560
IT0862L	SAP HANA Upgrade -LGE21				3,080,001		3,080,001
IT0863L	SAP Roadmap Strategy -LGE21				44,000		44,000
IT0864L	Sec Infra Enhance-LGE21				52,000		52,000
IT0865L	Server Capacity Expan-LGE21				32,267		32,267
IT0866L	Server Hardware Refresh-LGE21				295,360		295,360
IT0867L	LogRhythm HW Refresh-LGE19				780,000		780,000
IT0868L	Simpsonville Electr Upg-LGE21				25,996		25,996
IT0869L	Simpsonville Furniture-LGE21				13,000		13,000
IT0870L	Site Sec Improvements -LGE21				26,000		26,000
IT0871L	SiteScan Upgrade-LGE21				26,000		26,000
IT0873L	Tech Refesh desk/lap-LGE21				1,236,648		1,236,648
IT0874L	Telecom Site Renov-LGE21				52,000		52,000
IT0876L	Transmission Outage App-LGE21				44,000		44,000
IT0878L	Video Streaming Appl Upg-LGE21				52,000		52,000
IT0879L	Voice Infrastructure Exp-LGE21				78,000		78,000
IT0880L	Vuln Scanning - Refr-LGE21				104,000		104,000
IT0881L	Wireless Upgrade (WERUS)-LGE21				91,000		91,000
IT0882L	WMS Enhancements-LGE21				132,000		132,000
IT0883L	T1 Sunset - Yr 1/5-LGE21				234,000		234,000
IT0884L	Level 2 Infrast Refresh-LGE21				130,000		130,000
IT0885L	Exch 2019 Upgr w/HW Refr-LGE21				145,600		145,600
IT0886L	Firewall Mgmt Tech Refr-LGE21				156,000		156,000
IT0887L	DB Refresh-LGE21				78,000		78,000
IT0888L	Windows 10 CBB upgrade-LGE21				208,001		208,001
IT0889L	SCCM Upgrades-LGE21				41,600		41,600
IT0890L	Ivanti AppSense Env Mgr-LGE21				54,597		54,597
IT0891L	XenDesktop Maj Upgr-LGE21				82,116		82,116
IT0892L	Phone HW Refresh 1 of 3-LGE21				273,000		273,000
IT0893L	Trimble / Ghent Replace-LGE21				57,200		57,200
IT0894L	Upgr Vmware Infrastr-LGE21				98,800		98,800
IT0895L	Trams GIS Enhancements-LGE21				110,000		110,000
IT0896L	Trams Lines Work Mgmt-LGE21				88,000		88,000
IT0897L	Trans Lines Mobile Insp-LGE21				176,000		176,000
IT0898L	ITSM Tools-LGE21				156,000		156,000
IT0899L	Rate Case Filing 2020-LGE21				198,000		198,000
IT0900L	MR Hardware-LGE21				22,000		22,000
IT0901L	SAP Data Arch/Purging-LGE21				110,000		110,000
IT0902L	Readerboard Upgrade-LGE21				66,000		66,000
IT0903L	Low Inc Asst Agency Prtl-LGE21				22,000		22,000
IT0904L	Rev Col Impl Transcentra-LGE21				22,000		22,000
IT0905L	iPad Refresh Project-LGE21				678,080		678,080
IT0906L	Tripwire SW Upgrade-LGE21				67,600		67,600
IT0907L	Machine Health Mgr Upgr-LGE21				44,000		44,000
IT1000L	UC4 upgrade to V14-LGE22					26,000	26,000
IT1001L	CIP Compl Tools - Yr12-LGE22					130,000	130,000
IT1002L	Compl Infrast - Year 12-LGE22					260,000	260,000
IT1003L	Telecom Site Renovation-LGE22					52,000	52,000
IT1004L	Netwk Acc Dev Site Infr-LGE22					78,000	78,000
IT1005L	Access Switch Rotation-LGE22					260,000	260,000
IT1006L	CERUS IV-LGE22					208,000	208,000
IT1007L	Bulk Power & Environ Sys-LGE22					78,000	78,000
IT1009L	Elimin of Lease T1 Circ-LGE22					234,000	234,000
IT1010L	Site Security Improve-LGE22					26,000	26,000
IT1011L	Outside Cable Plant -LGE22					104,000	104,000
IT1012L	Network Test Equipment-LGE22					65,000	65,000
IT1013L	SAN Capacity Expansion-LGE22					156,000	156,000
IT1014L	Core Network Infrast-LGE22					78,000	78,000

Project	Description	2018	2019	2020	2021	2022	Grand Total
IT1015L	Netwk Acc Dev and Gateway-LGE22					18,981	18,981
IT1016L	KY SDN Impl (Phase 1)-LGE22					130,000	130,000
IT1017L	Network Management-LGE22					19,500	19,500
IT1018L	Netwrk Mgmt Tech Refresh-LGE22					169,000	169,000
IT1019L	NPM Tech Refr (Netscout)-LGE22					104,000	104,000
IT1020L	ITSM Upgrade-LGE22					104,000	104,000
IT1021L	Impl SD-WAN (Phase 1)-LGE22					52,000	52,000
IT1022L	SIEM(CIP) HW,etc-LGE22					31,200	31,200
IT1023L	SIEM(Corp) HW,etc-LGE22					31,200	31,200
IT1024L	IT Sec and CIP Labs Enh-LGE22					26,000	26,000
IT1025L	Endpoint Pro Lic and Grw-LGE22					2,600	2,600
IT1026L	Data Loss Prevention-LGE22					44,460	44,460
IT1027L	Security Infrast Enhance-LGE22					52,000	52,000
IT1028L	Citrix XenMobile Upgrade-LGE22					36,921	36,921
IT1029L	Netwk Access Cont(KY/PA)-LGE22					260,000	260,000
IT1030L	Tech Refr Bluecoat Proxy-LGE22					234,000	234,000
IT1031L	Voice Infrast Expansion-LGE22					78,000	78,000
IT1033L	Wireless Buildout-LGE22					78,000	78,000
IT1034L	Guest Wireless Upgrade-LGE22					31,200	31,200
IT1035L	Contr Upgr/Failover Shar-LGE22					150,800	150,800
IT1036L	IP MGmt Refresh Project-LGE22					208,000	208,000
IT1037L	Cabling for Srvr Connect-LGE22					23,400	23,400
IT1038L	Louisville Elect Upgrs-LGE22					26,000	26,000
IT1039L	Louisville Rack and Furn-LGE22					13,000	13,000
IT1040L	Srvr Cap Exp and Reliab-LGE22					44,200	44,200
IT1041L	Server Hardware Refresh-LGE22					234,000	234,000
IT1042L	Simpsonville Elect Upgr-LGE22					26,000	26,000
IT1043L	Simpsonvle Furn and Rack-LGE22					13,000	13,000
IT1044L	Mobile Radio-LGE22					104,000	104,000
IT1046CG	LGE Twr Rep (Muld)(Yr 1)-LGE22					50,000	50,000
IT1047L	StackVision Upgrade-LGE22					104,000	104,000
IT1048L	EMS Security Enhance-LGE22					53,040	53,040
IT1049L	PS App/PeopleTools Upgr-LGE22					75,000	75,000
IT1050L	Comp HW Capital for LOBs-LGE22					192,400	192,400
IT1051L	Monitor Replacement-LGE22					55,120	55,120
IT1052L	MF Dev Growth and Refr-LGE22					20,800	20,800
IT1053L	Pers Prod Grwth and Refr-LGE22					52,000	52,000
IT1054L	Tech Refr Dkstp and Lptp-LGE22					1,386,739	1,386,739
IT1055L	LOAD -vendor upgrade-LGE22					66,000	66,000
IT1056L	TOA- Trans Outage App -LGE22					44,000	44,000
IT1057L	Centrify Licensing-LGE22					10,400	10,400
IT1058L	Mobile/Wrkstn Lic Trueup-LGE22					35,360	35,360
IT1059L	Rate Case Filing 2021-LGE22					66,000	66,000
IT1060L	SAP S4 Upgrade-LGE22					1,320,001	1,320,001
IT1061L	Cust Serv Roadmap Strat -LGE22					220,000	220,000
IT1062L	Avaya Release Upgrade-LGE22					110,000	110,000
IT1063L	Rev Col-Experian Contrct-LGE22					22,000	22,000
IT1064L	Microsoft EA-LGE22					200,200	200,200
IT1065L	Microsoft License Trueup-LGE22					78,000	78,000
IT1066L	SAN Refresh-LGE22					560,560	560,560
IT1067L	SONET Repl Prov/Mon Sys-LGE19		65,000				65,000
IT1068L	CyberArk Corp SW/HW Upgr-LGE22					65,000	65,000
IT1069L	Oracl NMS OSI DSCADA Upg-LGE22					440,001	440,001
IT1070L	Oracl NMS DERMS Mod Impl-LGE22					132,000	132,000
IT1071CG	Gas Facility Inspections-LGE22					250,000	250,000
IT1072L	SOA Middleware Upgrade-LGE22					78,000	78,000
IT1073L	DB Refresh-LGE22					78,000	78,000
IT1074L	Windows 10 CBB upgrade-LGE22					208,001	208,001
IT1075L	SCCM Upgrades-LGE22					41,600	41,600
IT1076L	XenDesktop Major Upgrade-LGE22					104,127	104,127
IT1077L	Upgr Vmware Infrastr-LGE22					104,000	104,000
IT1078L	Trans GIS Enhancements-LGE22					88,000	88,000
IT1079L	Trans Lines Work Mgmt-LGE22					44,000	44,000
IT1080L	Trans Lines Mobile Inspt-LGE22					88,000	88,000
IT1081L	ITSM Tools-LGE22					52,000	52,000
IT1082L	MR Hardware-LGE22					22,000	22,000
IT1083L	Low Inc Asst Agency Prtl-LGE22					22,000	22,000
IT1084L	iPad Refresh Project-LGE22					104,000	104,000
IT1085L	GIS Enhancements-LGE22					176,000	176,000
IT1086L	SONET Equip Repl Yr 1/4-LGE19		390,000				390,000
IT1087L	SONET Equip Repl Yr 2/4-LGE20			390,000			390,000
IT1088L	SONET Equip Repl Yr 3/4-LGE21				390,000		390,000
IT1089L	SONET Equip Repl Yr 4/4-LGE22					390,000	390,000
141390	Environmental Equipment LGE	17,500	17,500	17,500	17,500	17,500	87,500
145402	HR Cap Equip Improvmnts LGE	9,800	9,800	9,800	9,800	9,800	49,000
145400	Auburndale Plating Storage			200,000			200,000
149344	SC CAPITAL - 2016 BP - LGE	200,000	20,000		500,000		720,000
SC0005	SSC Storeroom-LGE19		512,200				512,200
SC0006	SSC Storeroom Racks-LGE19		51,220				51,220

Project	Description	2018	2019	2020	2021	2022	Grand Total
148396	Prop. Tax Cap. - LGE Non-Mech	351,393	916,818	1,123,068	1,337,059	549,901	4,278,239
	Total	**610,864,725**	**588,695,051**	**437,165,069**	**423,593,040**	**258,338,011**	**2,318,655,895**

Investment Proposal for Investment Committee Meeting on: December 20, 2017

Project Name: PC Tech Refresh

Total Expenditures: $2,976k

Project Number(s): IT0287B

Business Unit/Line of Business: IT

Prepared/Presented By: Jeff Smith / Priya Mukundan

Executive Summary

LGE KU Energy (LKE) implemented a program in 2002 to replace desktops and laptops on a three-year cycle. The program was reevaluated in 2005 and it was determined then that the refresh cycle could be extended to four years for desktop computers. In 2017, the decision was made to begin refreshing Notebook computers on the same four year cycle due to advancements in technology, improved reliability and better warranties. The replacement cycle is consistent with industry norms as confirmed by Gartner, an American research and advisory firm that provides technology related insights to businesses.

The refresh process has continued to evolve over the years through various means. The 2014 Technology Refresh budget was reduced from its original budgeted amount by $230k, with the savings attributed to additional deferred replacements and from the implementation of a thin client software solution on repurposed older desktop machines. That reduction became the new baseline for Technology Refresh in subsequent years as LKE continues to deploy thin client technology, either a software solution or a hardware solution, where possible for desktop replacements. Thin client technology reduces the cost of desktop hardware equipment by 50% and extends the rotation cycle to an estimated 6 years. During the Tech Refresh process, devices are assessed for possible conversion. LKE currently has more than 500 thin clients deployed, including an additional 35 conversions in 2017.

In addition to the desktop and laptop refreshment, LKE also refreshes Toughbooks on a 4 year rotation. These are devices placed into service in 2014 and earlier for Electric and Gas Operations business. In 2018, some of these devices will be refreshed as part of the normal process while others will begin transitioning to iPad or other lower cost devices. This project is included in the 2018BP for $2,976k.

Background

This project is the continuation of current IT policy to provide upgrades to the Workstation infrastructure and will include implementation of the new Windows 10 operating system and deployment throughout the organization. The project will provide the rotation of approximately 1,200 new desktops, laptops and Toughbooks into the environment in 2018. The project maximizes operating efficiency for our knowledge workers and keeps IT support costs from increasing due to unplanned hardware maintenance.

- **Alternatives Considered**

  Recommendation for 2018 Refresh Project   NPVRR: $3,212k
  - Positive impact on business operations for 2018
  - Windows 10 will be deployed on most devices
  - Keep pace with advancing technology
  - Minimize risk to O&M budgets for repairs
  - Ability to rollout new applications required by the lines of business

  Alternative 1 "Do Nothing"
  - Negative impact on business operations for 2018   NPVRR: N/A
  - Not keeping pace with advancing technology
  - Risk to O&M budgets for repairs
  - Inability to rollout Windows 10 and other new applications required by the lines of business
  - This is not considered a viable long-term option because it poses productivity and down-time risks to operational areas dependent on the technology being updated.

  Alternative 2 "Defer Project"   NPVRR: N/A
  - Same as Alternative 1 "Do Nothing" and not considered a viable alternative
  - Schedule impact for rollout of new applications to lines of business

  Alternative 3 "Replace only failed equipment"   NPVRR: N/A
  - Same as Alternative 1 "Do Nothing" and not considered a viable alternative
  - Adverse effects to rolling out new applications required by the lines of business
  - Productivity impact and "down-time" for clients when equipment fails

  Alternative 4 "Extend rotation period to 5 years"   NPVRR: N/A
  - Same as Alternative 1 "Do Nothing" and not considered a viable alternative
  - Productivity impact and "down-time" for clients when equipment fails
  - Extended rotation cycle is not consistent with Gartner recommendation

Project Description

- **Project Scope and Timeline**

This project will evaluate and replace four year old desktops and laptops in 2018 before the workstations experience hardware problems that will cause out of warranty repair and client down time. The project will be completed by 12/31/2018. All LKE desktops, laptops, and Toughbooks that were purchased in 2014 will be evaluated for replacement. Where possible, thin clients will be used for replacements. The replacement schedule will be determined by site and will be reported monthly through departmental status reports. The project is budgeted and there are no incremental O&M expenditures or savings related to the project. There are avoided costs associated with this project including improved reliability, reduced downtime for clients, and out of warranty repair costs, etc.

Economic Analysis and Risks

- **Bid Summary**

The hardware for this project will be purchased under the PC Hardware and Peripherals Contract to ▉▉. In 2016, PPL and LKE issued a joint bid seeking a larger volume discount and synchronized the PA and KY contracts. ▉▉ was awarded the supplier contract for both PPL and LKE through a competitive bid process that included Minority-Owned and Woman-Owned businesses. ▉▉ was awarded the hardware contract for both PPL and LKE, and both companies will purchase the ▉ hardware through the ▉▉ supplier contract.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	2,976		-	-	2,976
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	2,976		-	-	2,976
4. Capital Investment 2018 BP	2,976	-	-	-	2,976
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	2,976	-	-	-	2,976
7. Capital Investment variance to BP (4-1)	-		-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$494
Contract Labor:	$227
Materials:	$2,255
Local Engineering:	$0
Burdens:	$0
Contingency:	$0
Reimbursements:	($0)
Net Capital Expenditure:	$2,976

- **Assumptions**
  - Workstations will be available and delivered in 14 business days or less after order.
  - Cost per workstation will not shift dramatically during the year.
  - Contract labor will be available and no reduction of internal labor will occur.

- **Environmental**
  No environmental impact.

- **Risks**
  If the project is not approved, the main risk would include aging hardware that could fail that would create disruptions to individuals and processes. Hardware replacement after failure would be expected to be more costly than replacing prior to failure, along with the negative productivity impact to employees that experience unplanned hardware failure.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the 2018 PC Tech Refresh project for $2,976k to ensure that our workstation environment meets the needs of the operational areas who are dependent upon the tools and technology to do their job.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		President and Chief Operating Officer	

Arbough

Investment Proposal for Investment Committee Meeting on: September 27, 2017

Project Name: ARM Work Management System Upgrade

Total Expenditures: $2,500k (Including $227k of contingency)

Project Number(s): ITO300B

Business Unit/Line of Business: IT/ Electric Distribution Operations (EDO) / Gas Distribution Operations (GDO)

Prepared/Presented By: Joseph Justice, Steve Woodworth, Tom Rieth

Executive Summary

EDO and GDO request funding authorization to upgrade their work management system, ███'s Asset and Resource Management (ARM) software. ARM is a critical system used to manage many facets of daily work and resources, including capital construction, distribution system maintenance, and regulatory required inspections.

Since implementing ARM in 2012, LKE has not upgraded the software. The existing version, v.1.4.2, is no longer covered by ███'s standard support. Therefore, LKE is paying a premium on software support and maintenance through 2018 with ███willing to renegotiate beyond 2018 if desired. In addition to vendor support, timing of this project is influenced by other major initiatives. The ARM Upgrade schedule was originally set to avoid overlap with several large information technology projects, including Distribution Automation (DA), Advanced Metering System (AMS), and the Geographic Information System (GIS) replacement. With the recent delay of AMS and GIS, now is the opportune time to upgrade ARM. Otherwise, the upgrade window would move to 2021+ impacting support costs as well as critical system patches / upgrades.

The latest release of the ARM software upgrades the Work Manager to HTML5 with a state-of-the-art web user interface, enhancing usability and productivity improvements. Many of the enhancement requests from the LKE ARM User Group are baseline functionality in the latest version. Examples include changes for the display configuration and implementing advanced query functions.

EDO and GDO recommend that the Investment Committee approve the proposed project for the capital cost of $2,500k, including a $227k contingency. There is no incremental on-going O&M, and an actual reduction in O&M of $41k during 2018. The 2017BP includes allocation of $2,350k for the project, of which $300k is in 2017. The 2018BP includes $2,350k in 2018.

Background

■■■s Asset and Resource Management (ARM) solution replaced STORMS WMS in 2012, for managing work and resources in EDO and GDO. The current ARM solution is version 1.4.2, and has not been upgraded since the implementation. This version is outside of the vendor's standard support window, so LKE is paying a premium on a year-by-year support contract. In addition to the cost of support, LKE's ability to implement enhancements to support business processes is limited.

LKE Electric and Gas Distribution utilize multiple work management systems. GDO currently uses both Maximo and ARM, but recognizes the benefit of consolidating into a single work management application. This upgrade will position GDO to migrate Maximo users to ARM in the future. EDO currently uses ARM and Cascade, a system used by Substation Construction and Maintenance. The proposed upgrade will also provide EDO with an option to consolidate all work management into one system in the future. However, replacement of Cascade was not included in the scope of the proposed upgrade due to time constraints and associated project complexities.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,526
     Implement the ARM Upgrade along with four system enhancements to meet business needs.

     These enhancements include the ability to export surveyed facilities results into Excel, incorporate the Facility Type and Facility ID as a concatenated field in Asset Manager, add an "Executed By" option to the query functionality in Asset Manager, and ability to include Work Request Owner when duplicating a work request.

  2. Alternative #1:   NPVRR: ($000s) $3,779
     Implement the ARM Upgrade and convert Gas Maximo to ARM Asset Manager

     This option is not recommended as it would increase the duration of this project by five months. Keeping Maximo will not adversely impact the business since it has the functionality to meet the critical needs of GDO.

     Distribution is implementing this upgrade to maximize available business and technical resources prior to other large-scale initiatives starting within the 2018 BP. For LKE to meet that timeframe, it will not be able to add the complexity to this project.

  3. Alternative #2:   NPVRR: ($000s) $4,297
     Delay upgrade until 2021+

     This option is not recommended as it would mean the ARM upgrade would not take place until 2021+. Waiting 10 years to apply system patches on a critical LOB system can pose risks that include incompatibility with interfacing systems, security

vulnerabilities, and break-fix complexities of a system not being maintained by though vendor.

Additionally, extended support is negotiated annually and continued increases in premium support costs should be expected as the vendor pushes for LKE to move to its standard supported version.

Finally, there are several other projects and programs in the 2018BP that would benefit from this initiative and delaying this upgrade to 2021 would prevent that.

Project Description

- **Project Scope and Timeline**

The scope of this project is to:

- Upgrade the current ARM version 1.4.2 to most current ARM version
- Include four critical business enhancements at a cost of $120k (developed by ████)

Milestones for this project are:

Milestone Number	Payment Milestone Description	Percent of Total Fixed Fee	Target Invoice Date
1	**Fully Executed Contract**	10	Dec 17
2	**Installation at LG&E and KU Complete**	15	Apr 18
3	**Complete Impact Analysis**	15	May 18
4	**Complete Design Document**	15	Jun 18
5	**Report and Solution Configuration Complete**	15	Jul 18
7	**User Acceptance Testing Complete**	10	Aug 18
8	**Deliver End User Training Materials**	10	Sep 18
9	**Go-live and Post Go-Live Support Complete**	10	Oct 18

- **Project Cost**

Total cost of the project is $2,500k, including $227k of contingency.

Economic Analysis and Risks

- **Bid Summary – sole sourced (Incumbent vendor)**

  ██████ quote for professional services is ████████ to assist in the implementation of this project. ████ is the Company standard for EDO and GDO work management. It was chosen through a competitive bid process in 2012.

  ██████ s bid for the professional services is ████ to perform performance testing for all lines of business in this project. ██████ was chosen to develop the LKE Testing Center of Excellence in IT

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	230	2,270	-	-	2,500
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	230	2,270	-	-	2,500
4. Capital Investment 2017 BP	300	1,300	750	-	2,350
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	300	1,300	750	-	2,350
7. Capital Investment variance to BP (4-1)	70	(970)	750	-	(150)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	70	(970)	750	-	(150)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	300	271	279	583	1,433
2. Project O&M 2017 BP	300	312	285	598	1,495
3. Total Project O&M variance to BP (2-1)	-	41	6	15	62

The proposed 2018 BP includes $2,350k in 2018, so with this amount and the amount expected to be spent in 2017 the BP amounts are sufficient to cover the total cost of the project.

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$350
Contract Labor:	$1,890
Materials:	$33
Local Engineering:	$0
Burdens:	$0
Contingency:	$227
Reimbursements:	($0)
Net Capital Expenditure:	$2,500

- **Assumptions**

  o ARM 2.2 will be setup in the Citrix XenApp 7.x environment and the current ARM 1.4.2 production environment will not be migrated from Citrix XenApp 6.5.
  o Minimal data migration efforts for LGE and KU since this task will be handled by ▮▮▮.
  o Current Work Manager Reports will continue working without any modifications. Asset Manager Reports may need updates to conform to the new database.
  o Current interfaces will continue working without modifications.
  o LKE resources will be available as needed to support the scope and schedule of the program.

- **Environmental**
  There are no known environmental concerns related to this proposal.

- **Risks**

  o The latest ARM offering consists of a new user interface which will be a change to the end users. Failure to complete this upgrade in a timely manner could result in too much change to the business given the other proposed initiatives identified in the business plan (AMS, DA, GIS).

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the project for the capital cost of $2,500k, including a $227k contingency. There is no incremental on-going O&M and a reduction of $41k in 2018.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: 7/26/2017

Project Name: Barton Substation Upgrade Project

Total Expenditures: $4,781k   (Including $656k of contingency)

Project Number(s): Distribution-154504, Substation-154118, Transmission-154511

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tim Smith/Kevin Patterson/Daniel Hawk

Executive Summary
Electric Distribution Operations (EDO) – Electrical Engineering and Planning seeks funding authority to build a new 22.4MVA, 69kV/12kV distribution substation with two 12,470 volt feeder circuits and to make the associated system improvements to support new load growth in the Bardstown, Kentucky area in Nelson County. This funding request includes costs to convert the Barton 4kV (8281) system to 12kV. The existing Barton 4kV Substation (7MVA capacity) is expected to continue to exceed its summer rating due to operations and facility expansions by the two largest customers served, Barton Distillery and the City of Bardstown. This New Business project provides for substation improvements necessary to serve the expected new loads, provides for future growth and makes provisions for future substation expansion. Upon completion of the proposed 22.4MVA, 69/12kV substation on the new greenfield site, the existing Barton 4kV Substation, located on distillery property, will be razed and the associated substation lot easement rights reverted to the Barton Distillery.

Approval is requested in the amount of $4,781k to construct the Barton 22.4MVA, 69/12kV Substation. This project was not included in EDO's 2017 Business Plan (BP) because the notice from Barton Distillery on the new load was received after the 2017 BP was finalized. The 2017 funding was approved through the Corporate RAC process and the 2018 funding is included in EDO's proposed 2018 BP.

Background
Barton 4kV Substation is a single transformer substation built on a 60' by 60' easement on the Barton Distillery property at ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮ in Bardstown, Kentucky. The existing substation transformer is a 7MVA, General Electric LTC 67kV/4.360kV (4kV system) transformer manufactured in 1962 and installed at its present location in 1969. The current summer forecast for Barton 4kV is 106% of top name plate (the summer rating is 100% of top name plate). The Barton 4kV system is a summer peaking system and the substation transformer had an actual 2016 summer peak of 7.6MVA (109%).

There are two 4kV distribution circuits served from the current Barton 4kV Substation. Circuit #2201 serves the City of Bardstown Municipality. The City of Bardstown has requested to serve

an additional 1.1MVA of capacity on this circuit. The second circuit out of the Barton 4kV Although Substation, circuit #2202 serves the Barton Distillery and three residential customers. Barton Distillery is adding a new dryer house facility with an expected increased demand of 1.9MVA.

The anticipated summer demand for the Barton 4kV Substation will be 10.6MVA (151%) when all customer requests and the plant expansions are completed and fully operational. This would result in the substation transformer exceeding its summer emergency rating of 120% (likely to occur in the summer of 2018, if no remediation steps are taken). The City of Bardstown has agreed to transfer load presently served from the Barton 4kV Substation to another municipal substation during the construction to relieve the forecasted overload.

The existing substation site has several limiting factors that make it undesirable for expansion. The 60' by 60' substation easement site is too small for a standard designed substation and cannot accommodate a second transformer for future load growth or N1DT contingency considerations. In order to make the property suitable for an upgraded transformer, additional land would need to be acquired and major property improvements would be required. These improvements include adding large amounts of fill material and a significant retaining wall due to the severe slope of the property outside the existing substation fence. In addition, the substation's very close proximity to the distillery's storage tank facility would make working on the site difficult.

EDO requests $4,781k in funding to resolve the current and forecasted overload condition at Barton 4kV Substation. EDO proposes construction of a new substation on a 150' by 150' greenfield site on Barton Distillery property, south of the existing Barton 4kV site off Cathedral Manor Road. Funding is requested to install a new 22.4MVA, 69/13.09kV transformer, a 69kV transmission extension to the new substation and two 397kCM ACSR exit circuits. An operating voltage conversion from 4kV to 12kV is also proposed to enhance the distribution feeders and to promote future contingency ties to other 12kV substations in the surrounding Nelson County area. The Barton system is well positioned for a 4kV to 12kV conversion as there are only about 6 distribution line transformers on the Barton Distribution system that are not already dual voltage transformers (capable of conversion to 12kV).

A Transmission Service System Impact Study for a new service point has been submitted and no additional transmission improvements are expected to be identified beyond the cost to serve the new station.

- **Alternatives Considered**
    1. Recommendation Option: NPVRR: ($000s) $5,560k
       The recommended option is to design and build a new 12kV substation on Barton Distillery property with a 22.4MVA LTC Transformer. The project includes site preparation, four breakers, a control house, 69kV transmission extension to serve a new delivery point, two 12kV exit circuits and easement costs for this new substation site at ▮▮▮▮▮▮▮▮▮▮▮▮ in Bardstown, Kentucky. The cost also includes the demolition and removal of the existing Barton 4kV substation. The cost of the recommended option is $4,781k.

2. Do Nothing Option: NPVRR: ($000s) N/A
   KU has an obligation to serve the customers and associated load within the service area. The "do nothing" option is not considered an acceptable option because Barton 4kV would exceed Distribution Planning's operation limits for a 7MVA distribution substation power transformer. This practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1:   NPVRR: ($000s) $5,755k
   Design and build a one transformer substation on the existing Barton 4kV Substation site with a 22.4MVA LTC transformer. This option includes four breakers, a control house, a 69kV transmission tap, two exit circuits, easement costs, installation of the portable substation and site remediation. This option is not recommended for several reasons. The existing facility sits on top of a knoll and to expand the site would require additional property, a large amount of fill material, and a significant retaining wall. The site is very close to Barton Distillery's tank storage facility, limiting the amount of available space to the rear of the substation, making expansion difficult. This option would require the installation of a portable substation during construction and suitable space is very limited. Expansion of the existing site would not accommodate a second transformer for future load growth or N1DT contingency considerations. The cost of this option is $4,935k.

Project Description

- **Project Scope and Timeline**
  Transmission Project # 154511: Est. cost: $514k (2018-$514k)
  Install transmission poles and lines for a tap at the end of the existing 69kV transmission line for a new 69kV delivery point off ███████████████.

  Substation Project # 154118: Est. cost: $4,167k (2017-$1,402k, 2018-$2,366k, 2019-$399k)
  Perform a geotechnical survey, site prep, and service road construction needed for the development of the greenfield site between two existing warehouses on Barton Distillery property. Install substation steel structure, one 22.4MVA, 69/13.09kV substation transformer, circuit breakers and the associated substation equipment.

  Distribution Project # 154504: Est. cost: $100k (2017-$75k, 2018-$25k)
  Replace the 4kV distribution transformers, insulators, lightning arrestors and required pole replacements to convert the Barton 4kV distribution system to 12kV. Install two 397kCM ACSR overhead exit circuits and a 550' 397kCM ACSR line extension to tie to the existing distribution circuit.

Timeline

May 2017:	Site survey.
July 2017:	Open project.
July 2017-Dec. 2017:	Complete transmission, substation and distribution engineering design. Complete material and equipment orders.
Jan. 2018-May 2018:	Install service road, site prep, install fence footers & enclosure, concrete piers. Transmission tap construction. Distribution circuit construction.
May 2018 Sept. 2018:	Steel structure delivery and construction. Transformer and breaker delivery and installation. Installation of communications and control house.
Sept. 2018-Nov. 2018:	Site cleanup and landscaping. Substation in service.
Nov. 2018-March 2019	Equipment removal and demolition of Barton 4kV substation.

- **Project Cost**
  The total estimated cost of the project is $4,781k. Cost estimates are consistent with the "Conceptual Level 1" engineering design designation. Due to some uncertainty in the raze/removal cost of the existing 4kV substation, there is an estimated 16% contingency ($656k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - o The substation transformer and breakers will be ordered using existing contracts following established Supply Chain practices. Bids for other substation materials, transmission materials, and labor will be prepared as necessary following established Supply Chain practices.
  - o Transmission and Distribution Lines will use existing material and labor contracts and follow established Supply Chain procedures.
- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,477	2,894	-	-	4,371
2. Cost of Removal Proposed	-	10	400	-	410
3. Total Capital and Removal Proposed (1+2)	1,477	2,904	400	-	4,781
4. Capital Investment 2017 BP	-	-	-	-	-
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(1,477)	(2,894)	-	-	(4,371)
8. Cost of Removal variance to BP (5-2)	-	(10)	(400)	-	(410)
9. Total Capital and Removal variance to BP (6-3)	(1,477)	(2,904)	(400)	-	(4,781)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was not incorporated into the 2017 BP. The 2017 funding has been approved through the Corporate RAC process. The 2018 and 2019 amounts are incorporated in the proposed 2018 BP as New Business.

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 243
Contract Labor:	$ 2,533
Materials:	$ 674
Local Engineering:	$ 412
Burdens:	$ 263
Contingency:	$ 656
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 4,781

- **Assumptions**
    - Projected load growth at Barton Distillery and the City of Bardstown will be as expected.
    - The City of Bardstown (municipal) will complete the conversion of 4kV loads to alternative sources on a temporary basis and complete a 4kV to 12kV conversion within 18 months. This eliminates the need for a portable substation to be installed.
    - No adverse findings will be revealed from the site and geotechnical surveys of the new substation property.
    - An AT&T line that crosses a portion of the proposed substation site can be relocated as estimated.
    - The project unknowns will not exceed the estimated contingency amounts.

- **Environmental**
There are no known environmental issues at this time

- **Risks**
A deferment of this project will result in significant (above emergency) overloading of the existing 7MVA substation transformer. This overload will result in a loss of life for the transformer and could result in the failure and unplanned replacement of a high cost asset. A failure of the transformer would result in an extended outage (+24 hours) for two large customers in Nelson County, Kentucky.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Barton Substation Upgrade Project for $4,781k to serve existing load and proposed customer expansions in Nelson County, Kentucky.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: December 19, 2018

Project Name: BR3 HP-IP Blading

Total Expenditures: $ 3,585k (Including $179k of contingency)

Project Number(s): 144722

Business Unit/Line of Business: Generation

Prepared/Presented By: Mark Brackett

Executive Summary
The execution of this project will replace a substantial portion of the blading on the HP-IP turbine on BR3 (reference illustration in Appendix A). The prior turbine dismantle and overhaul was performed in 2012. During this inspection, it was recommended that IP turbine 3rd and 4th stage of rotating and stationary blading (rows R13, R14 and 13C, 14C) be replaced due to SPE (Solid Particle Erosion). Due to the extensive amount of reheater work performed since the last inspection, it is highly recommended to replace the 1st and 2nd stage (rows R11, R12, 11C and 12C) of rotating and stationary blading as well. It was also recommended on the HP turbine that stages 1st through 4th (rows R1, R2, R3, R4) be replaced due to blade untwist and FOD (Foreign Object Damage) and (rows 1C, 2C) be replaced due to FOD. This work can only be performed with the turbine disassembled. The first opportunity to perform this work is the Fall of 2019. The next opportunity will be in 2026. Due to possible blade failure causing extensive damage to the turbine and reduced unit reliability, it is highly recommended to replace the blading in 2019. This project was budgeted for $3,433k in the 2019 BP with all spend to occur in 2019. The total project cost is now estimated to be $3,585k, with $550k being spent in 2018, and the remaining $3,035k in 2019. The cost added to 2018 was funded by the RAC in the 8+4 forecast.

Background
E.W. Brown Unit 3 turbine/generator was disassembled and inspected during the last major outage in 2012. Condition based assessments recommended the following turbine blade rows for replacement during the next turbine/generator overhaul.

IP Blade Rows R11, R12, R13, R14, 11C, 12C, 13C and 14C Indications noted solid particle erosion on the trailing edge of the 3rd and 4th stage blades. Although the 1st and 2nd stage blades were replaced during the 2012 outage, they will need to be replaced again due to the extensive amount of reheater work performed since the last turbine overhaul. The reheater work was performed on an emergent basis due to the boiler tube leaks incurred during operation of the unit. The repairs performed on the reheater result in the liberation of oxide layers from the ID of the boiler tubes that become entrained in steam flow going to the IP turbine resulting in accelerated wear on the blading. Modifications to the reheater to address the recurrent boiler tube failures will be performed during the maintenance outage planned for the Fall of "19". Due to decreased

unit reliability and possible blade failure, it is highly recommended to replace the 1st, 2nd, 3rd through 4th stage blading in 2019.

HP Blade Rows R1, R2, R3, R4, 1C and 2C Indications noted the 1st through the 4th stages of rotating blades (R1, R2, R3 and R4) be replaced to preclude failure due the blade untwist and FOD. Indications also note the 1st and 2nd stage of stationary blades (1C and 2C) be replaced to preclude failure due to FOD.

By replacing these blades, reliability will increase by reducing the possibility of blade failure in this area of the turbine. This will be beneficial to both the company and the customer by improving BR3 reliability and allowing generation fleet to be dispatched in the most cost effective manner.

Alternatives Considered
1. Recommendation: NPVRR: ($000s) $3,980
2. Alternative #1:   NPVRR: ($000s) $4,121
3. Alternative #2:   NPVRR: ($000s) $5,127

Recommendation-Replace HP-IP Turbine Blading in 2019 Major Outage
Purchase and install the HP-IP in kind turbine blading in the Fall outage of 2019. This plan will be the most cost effective over the life of the project. It will decrease the potential of loss generation and extensive turbine damage due to the possibility of blade failure. The NPVRR for this alternative is $3,980k.

Alternative #1: Replace at Next Outage
We would need to open and inspect the blading at least once between each major outage to reduce the risk of blade failure and severe damage to the machine. During this inspection weld repairs on the blading would likely be required. This alternative is not recommended due to the incremental outage time and labor resources required. The NPVRR for this alternative is $4,121k.

Alternative #2: Do Nothing
The Do Nothing alternative is not recommended due to a continued potential of loss generation and a very high risk of blade failure causing severe damage to the machine. We would need to inspect the blading at least once between each major outage. This inspection would take 4 weeks to perform. If nothing is done and the blades are not replaced, it is highly likely at some point there will be a blade failure causing extensive damage to the turbine/generator set. This damage would cause approximately 12 weeks of unavailability. The total amount of lost generation, high labor cost for inspections and risks to the machine makes this alternative very unfavorable. The NPVRR for this alternative is $5,127k.

Project Description

- **Project Scope and Timeline**
  This project will replace in kind (14) rows of HP-IP turbine blades. (8) IP blade rows: R11, R12, R13, R14, 11C, 12C, 13C and 14C. (6) HP blade rows: R1, R2, R3, R4, 1C and 2C. The blading will be purchased from ▮▮▮▮▮▮▮▮ the OEM of the turbine/generator. The turbine will have to be opened up, old blades removed and new blades installed. Due to the labor resource requirements, the project execution timeline will be approximately (8) weeks. Blades will be ordered in 2018 for availability in December of 2019. A milestone payment will be made in December of 2018.

- **Project Cost**
  The total estimated cost of this project is $3,585k. This includes purchase of materials, cost of removal and installation. The total contingency of $179k (5%) is also included for unexpected issues of removal and installation during outage. There will be a total capital burden cost of $529k (20% stores burden on material purchased and the capital burdens).

Economic Analysis and Risks

- **Bid Summary**
  Labor and materials were competitively bid under the Turbine/Generator Major Outage Fleet wide initiative. Bids were solicited from ▮▮, and ▮▮▮▮▮▮ ▮▮▮▮▮▮▮▮▮. ▮▮▮ is expected to be awarded a contract for the material supply at a cost of ▮▮▮▮. ▮▮▮▮▮ is the preferred contractor for installation of the blades which is estimated at ▮▮▮.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	550	2,935			3,485
2. Cost of Removal Proposed		100			100
3. Total Capital and Removal Proposed (1+2)	550	3,035	-	-	3,585
4. Capital Investment 2019 BP	-	3,075			3,075
5. Cost of Removal 2019 BP	-	358			358
6. Total Capital and Removal 2019 BP (4+5)	-	3,433	-	-	3,433
7. Capital Investment variance to BP (4-1)	(550)	140	-	-	(410)
8. Cost of Removal variance to BP (5-2)	-	258	-	-	258
9. Total Capital and Removal variance to BP (6-3)	(550)	398	-	-	(152)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):   **Arbough**

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$0
Contract Labor:	$583
Materials:	$2,294
Local Engineering:	$0
Burdens:	$529
Contingency:	$179
Reimbursements:	($0)
Net Capital Expenditure:	$3,585

- **Assumptions**

  This projects assumes that the replacement of the HP-IP turbine blades will increase unit reliability by avoiding the possibility of turbine damage and loss of generation due to blade failure. Completing this project in 2019 will eliminate the extensive labor cost and 4 weeks of unit unavailability created by opening and inspecting the blading between the 2019 and 2026 major outages. The Replace at Next Outage and Do Nothing alternatives both assume escalation of three percent per year.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	
	a. Provide frequency or when equipment or component in question was last repaired or replaced. (7 – 30 years depending upon component)	Yes
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment?	
	a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

- **Risks**
The primary risk of not completing this project in 2019 is blade failure resulting in extensive damage to the turbine rotor and casing. By completing this project in 2019 it would restore the unit reliability by greatly reducing the possibility of blade failure. It would also eliminate the need to open the turbine and inspect the blades between major outages. This inspection takes an estimated 4 weeks to complete resulting in high labor cost and unit unavailability. Also completing this project in 2019 would be the most cost effective because it keeps the unit in the generation fleet for dispatch benefiting both the company and the customer.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the BR3 HP-IP Blading project for $3,585k to restore the unit reliability by greatly reducing the possibility of loss generation and turbine damage due to blade failure.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

APPENDIX A:

HP TURBINE

RIGHT SIDE
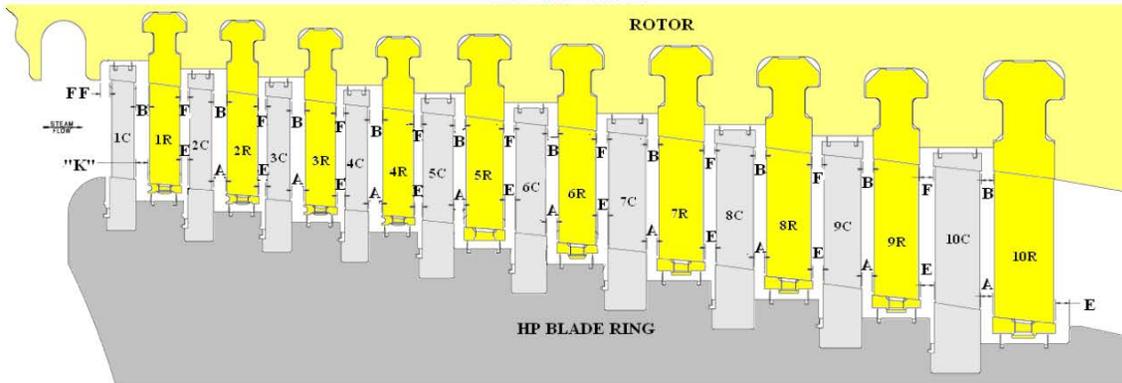
ROTOR

FF →

STEAM
FLOW

"K"

B F B F B F B F B F B F B F B F B F B

1C 1R 2C 2R 3C 3R 4C 4R 5C 5R 6C 6R 7C 7R 8C 8R 9C 9R 10C 10R

E A E A E A E A E A E A E A E A E A E

HP BLADE RING

IP TURBINE

RIGHT SIDE

ROTOR

FF →

STEAM
FLOW

B F B F B F B F B F B F B

15R 15C 14R 14C 13R 13C 12R 12C 11R 11C

E A E A E A E A E A

IP BLADE RING =2   IP BLADE RING =1
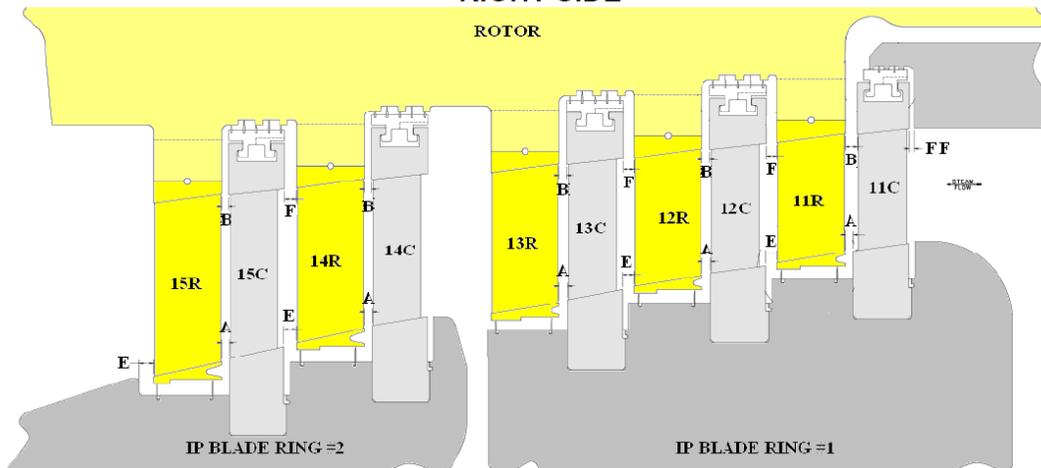
Combined Investment Proposal for Investment Committee Meeting on: <u>August 30th, 2017</u>

Project Name: <u>BRCT11 C-inspection</u>

Total Capital Expenditures: **$9,700k** (including $315k (3%) contingency)

Total Contract Expenditures (Sole Source): ███████

Project Number: Capital: <u>147949</u>

Business Unit/Line of Business: <u>Generation - EW Brown Plant</u>

Prepared/Presented By: <u>Greg Wilson</u>

Executive Summary

This proposal seeks approval for the capital required to perform a C-inspection on Brown Combustion Turbine Unit 11 (BRCT11), along with approval for a sole source award to ██████ ██████████ a business unit of ██████████████ for the purchase of parts and materials prior to the outage. The aforementioned scope of work will be performed under project 147949.

A C-inspection is performed when the equivalent operating hours (EOH) of an ████ combustion turbine unit reaches 24,000. EOH is used to estimate the material degradation of a unit's hot gas path parts and are accumulated on a per start basis. One start of the unit registers 20 EOH, and every operating hour accumulates one additional EOH. Trips and other events accumulate more EOH representing more stress placed on the machine during those occurrences.

BRCT11 is currently 23,099 EOH into its 24,000 EOH maintenance cycle and is the remaining ██████ unit at the site needing its first C-inspection. BRCT8, 9, & 10 combustion turbines installed in the mid 1990's have all undergone C-inspections in 2006, 2013, and 2015 respectively.

The total capital project is budgeted for $10,710k in the 2017 BP for $2,550k and $8,160k in 2017 and 2018, respectively. Through efforts to find third party providers for parts associated with the outage and through recent negotiations with ████████████ the plan is to reduce the 2018 spend to $7,150k making the total estimated project $9,700k.

The sole source procurement value requested for parts and materials from ████████████ to support the outage is ██████████.

Background

Material degradation of gas turbine parts can be attributed to two main factors, creep & thermal cycle fatigue. Creep is attributed to long term exposure to the high temperatures created in the combustion process whereas thermal cycle fatigue is caused by continual on/off cycling of the unit creating component thermal stress. In both cases, degradation of parts is very predictable and exceeding the manufacturer's replacement recommendation significantly increases the risk of failure.

The hot gas path components, which include; blades, vanes, liners, burners, and casings are replaced during a C-inspection. This replacement process is completed in order to meet the manufacturer's recommendation to maintain unit reliability and reduce risk of failure.

This is the first C-inspection for BRCT11. BRCT5 is scheduled for overhaul in the fall of 2017 where the majority of the hot gas path components will be taken out of service and replaced. The components that are capable of being refurbished for another cycle will be reconditioned and placed in service on BRCT11. Likewise, the parts that are removed from BRCT11 that can be refurbished will be placed in service on BRCT8 during its overhaul. The hot gas path component's proximity to the combustion process typically determines how many maintenance cycles a part can remain in service, and once it is taken out of service, whether it can be reconditioned or will need to be purchased new.

The scope of this project is to recondition the following components for installation in BRCT11. These assets are currently assigned to BRCT5, and will need to be transferred to in-service assets on BRCT11 after project completion.
- Row 1,2, & 3 vanes
- Row 1 & 2 blades
- Entry segments A & B
- Hot gas casing (HGC)
- Lower Combustor Insert (LCI)

- **Alternatives Considered**

  There are two possible options for continued operation of the unit. Both options are summarized below and evaluated in the attached CEM.

  1. Recommendation: NPVRR: ($000s) <u>$10,854</u>
     Perform the C-inspection as recommended by the OEM: 50 Day planned outage

  2. Alternative #1: NPVRR: ($000s) <u>$18,382</u>
     Do nothing and continue to operate without performing an inspection. This is not a viable option as it will only lead to a catastrophic failure for the unit. Long term exposure to creep and cyclic fatigue will inevitably lead to a failure of parts. Any failure of a component in the rotating section of the machine would lead to significant collateral damage that would escalate repair costs tremendously. The cost of returning the unit to service after such an event would be double the cost of a C-inspection and take a year to complete. The capital evaluation model assumes a 90% probability this will occur in 2021.

Project Description

- **Project Scope and Timeline**
  Capital Project 147949 (BRCT11 C-inspection) includes the materials and labor needed to complete a C-inspection. Included in ▮▮▮▮▮▮s scope are the following parts and services:

  - Labor to open the unit, replace / repair all components associated with a C-inspection, and to close the unit.
    - o Significant parts to be replaced are as follows:
      - Row 1, 2, & 3 blades
      - Row 1, 2, & 3 vanes
      - Hot gas casing (HGC)
      - Entry segment heat shields and carrier
      - Lower combustor insert

  - Perform applicable field service instructions (FSIs) to address reliability or maintenance issues.

  O&M Project BR11CIN (C-inspection) includes materials and labor needed to perform the following

  - Generator and rotor inspections.
  - Miscellaneous painting and maintenance correctives
  - Non-destructive testing of parts that are to remain for another maintenance cycle to ensure the part's integrity.

  An 8-week outage is currently scheduled for the fall of 2018 in the Power Generation outage plan to perform the outage.

  Significant Milestones associated with this project are as follows:

Aug 2017:	Seek Investment Committee approval
Sept 2017:	Place order to ▮▮▮▮▮▮ for parts associated with C-inspection
Jan 2018:	Enter into contract with ▮▮▮▮▮▮▮▮ for field services
Fall 2018:	Perform a C-inspection on BRCT11 (8 week outage)

- **Project Cost**
  The total cost for this project is expected to be $9,700K.

$000k	2017	2018	Totals
C-inspection 147949:	$2,550	$7,150	$9,700
Totals Capital requested:			**$9,700**
Totals (2017 BP):	$2,550	$8,160	$10,710

Economic Analysis and Risks

- **Sole Source Justification**
  Parts and materials needed to support the outage will be purchased from ██████████ under a sole source contract. The value of this contract is ██████. ████████████████████
  ██
  ██
  ██
  ██████

  These parts will be purchased with a series of standard purchase orders referencing a previously negotiated GSA that includes commercial terms. Terms will be added to the purchase order referencing liquidated damages if parts are not delivered on time. The table below summarizes the expenditures regarding the sole source.

Description	Costs ($000s)
Base scope C-inspection parts (new blades, vanes, carriers, heat shields…):	█████
Reconditioned parts from Unit 5 (blades, vanes, casing, liners, heat shields):	█████
Open and close parts for the unit to support the outage:	█████
FSI parts for miscellaneous improvements and upgrades:	█████
Total:	█████

  The current plan is to competitively bid the outage labor portion of the project at the beginning of next year.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,550	6,850			9,400
2. Cost of Removal Proposed		300			300
3. Total Capital and Removal Proposed (1+2)	2,550	7,150	-	-	9,700
4. Capital Investment 2017 BP	2,550	8,160			10,710
5. Cost of Removal 2017 BP		-			-
6. Total Capital and Removal 2017 BP (4+5)	2,550	8,160	-	-	10,710
7. Capital Investment variance to BP (4-1)	-	1,310	-	-	1,310
8. Cost of Removal variance to BP (5-2)	-	(300)	-	-	(300)
9. Total Capital and Removal variance to BP (6-3)	-	1,010	-	-	1,010

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed		343			343
2. Project O&M 2017 BP		343			343
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.3%
Capital Breakdown:	
Labor:	$90
Contract Labor:	$1,550
Materials:	$6,649
Local Engineering:	$328
Stores Burden & Taxes:	$768
Contingency:	$315
Net Capital Expenditure:	$9,700

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	NO
#2	Does the project involve equipment that is part of a regulated air emission unit?	YES
	a. Is change a like-kind or functionally equivalent replacement?	a. YES
#3	Does the project increase through-put with any of the material handling systems?	NO
#4	Will the project affect the dispatch order or utilization of the unit?	NO
#5	Does the project increase the emissions unit's maximum hourly heat input?	NO
#6	Does the project increase the emissions unit's electrical output (gross MW)?	NO
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	YES (See background section)
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	YES

Environmental Affairs has reviewed the project and has no issues from an NSR perspective.

- **Risks**

Risks associated with executing the project would include the possible requirement for additional funding to correct any unforeseen issues internal to the unit. Recent inspections have not indicated such problems, but with limited internal access the possibility exists. In the event that additional work or parts are required above the allowed approval level, Brown Plant will seek approval from the Investment Committee before granting authorization to proceed.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the BRCT11 C-inspection project for $9,700k (Capital) to ensure the reliability and dependability of the generating asset going forward, along with the sole source award to ▆▆▆▆▆▆▆ for parts and materials of ▆▆▆▆.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

**AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal**

SUBJECT: ████████████

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the sole source contract to ████████ for ████████ for parts associated with the Brown CT11 C inspection.

Proponent Greg Wilson Supervisor – Production		Manager Jerry Arnold Manager-Production	
Commercial Operations Sam Carr Manager - Commercial Operations		Commercial Operations Joe Clements Director –Power Gen. Commercial Operations	
Director Jeff Fraley General Manager, EW Brown		Vice President Ralph Bowling VP Power Production	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.
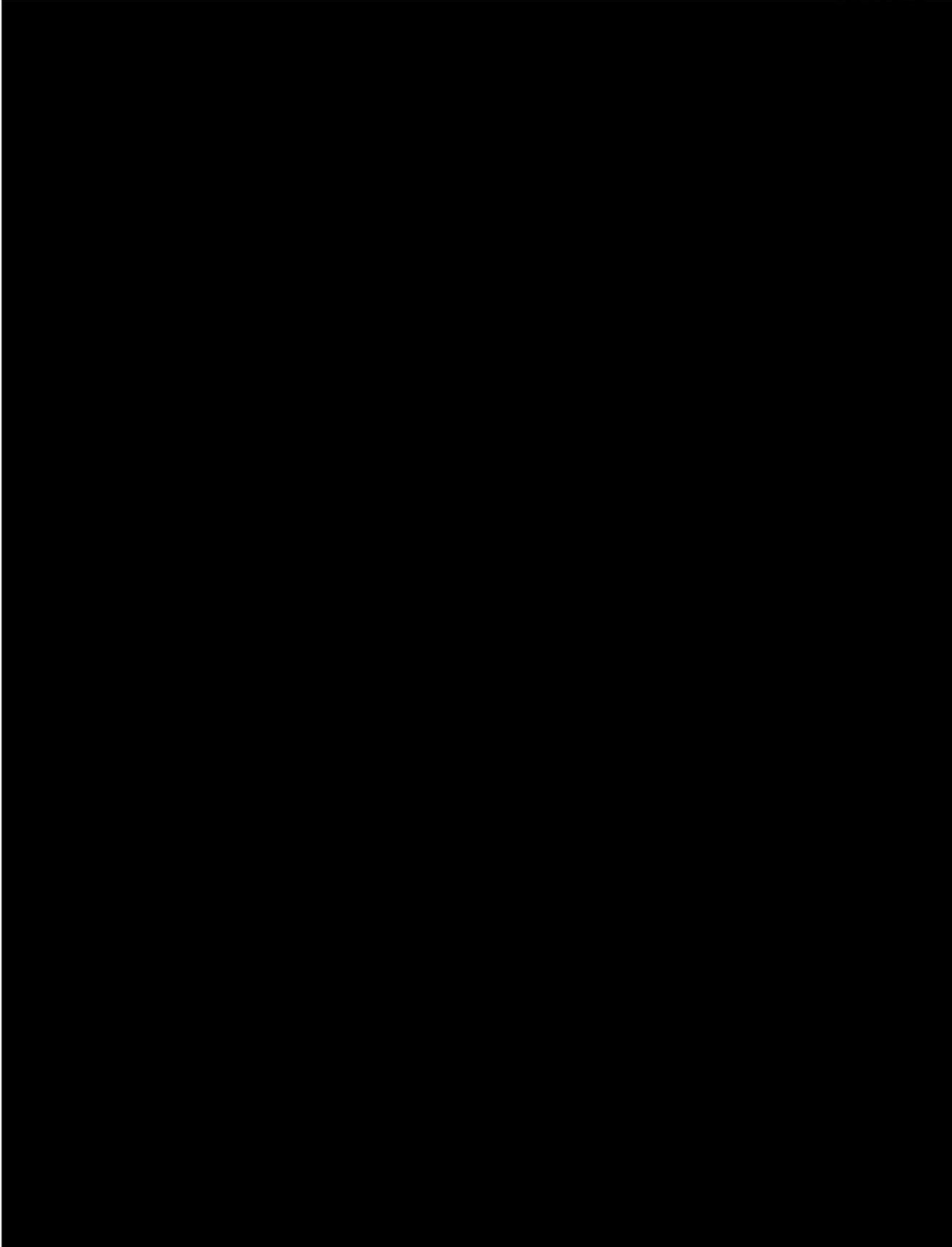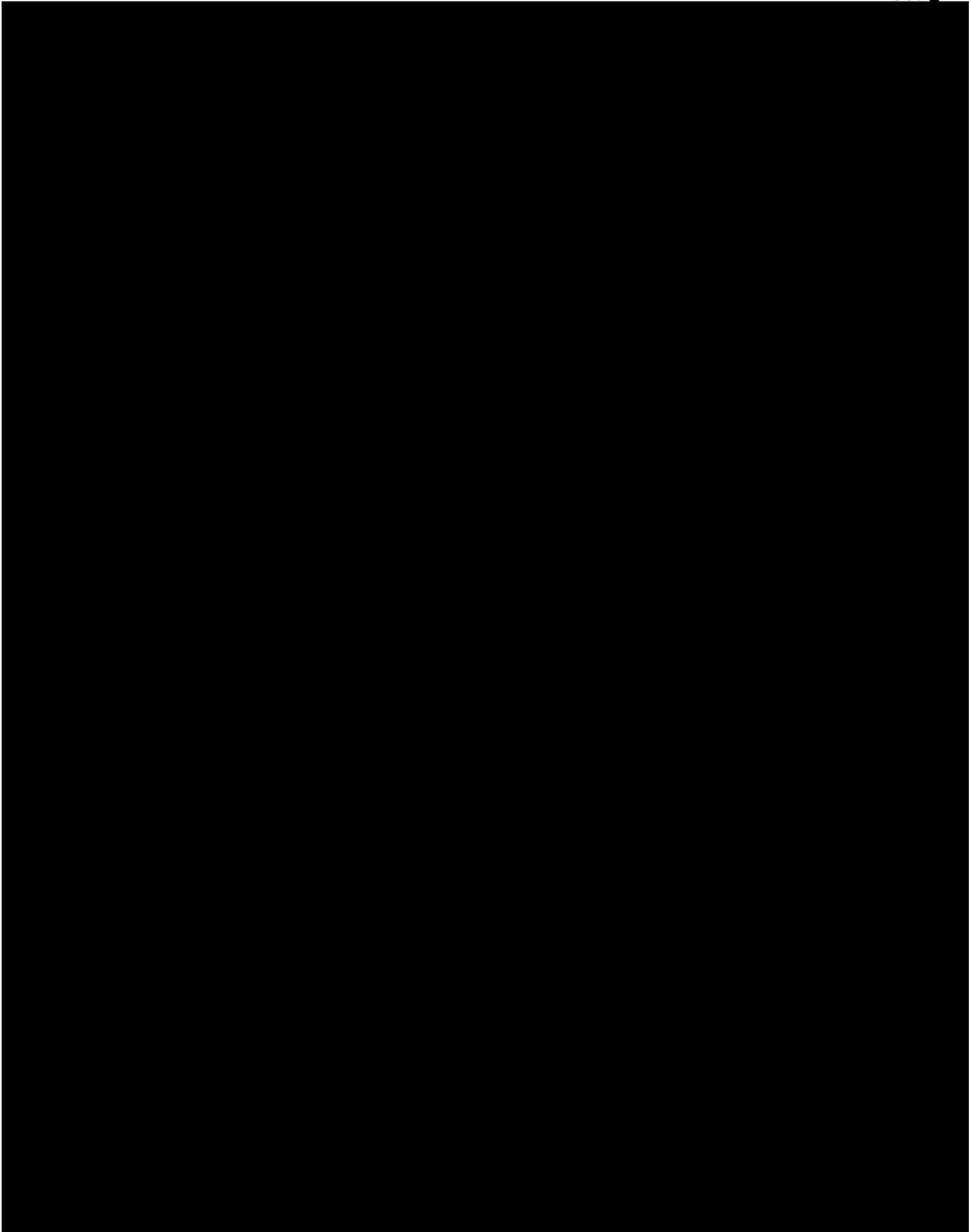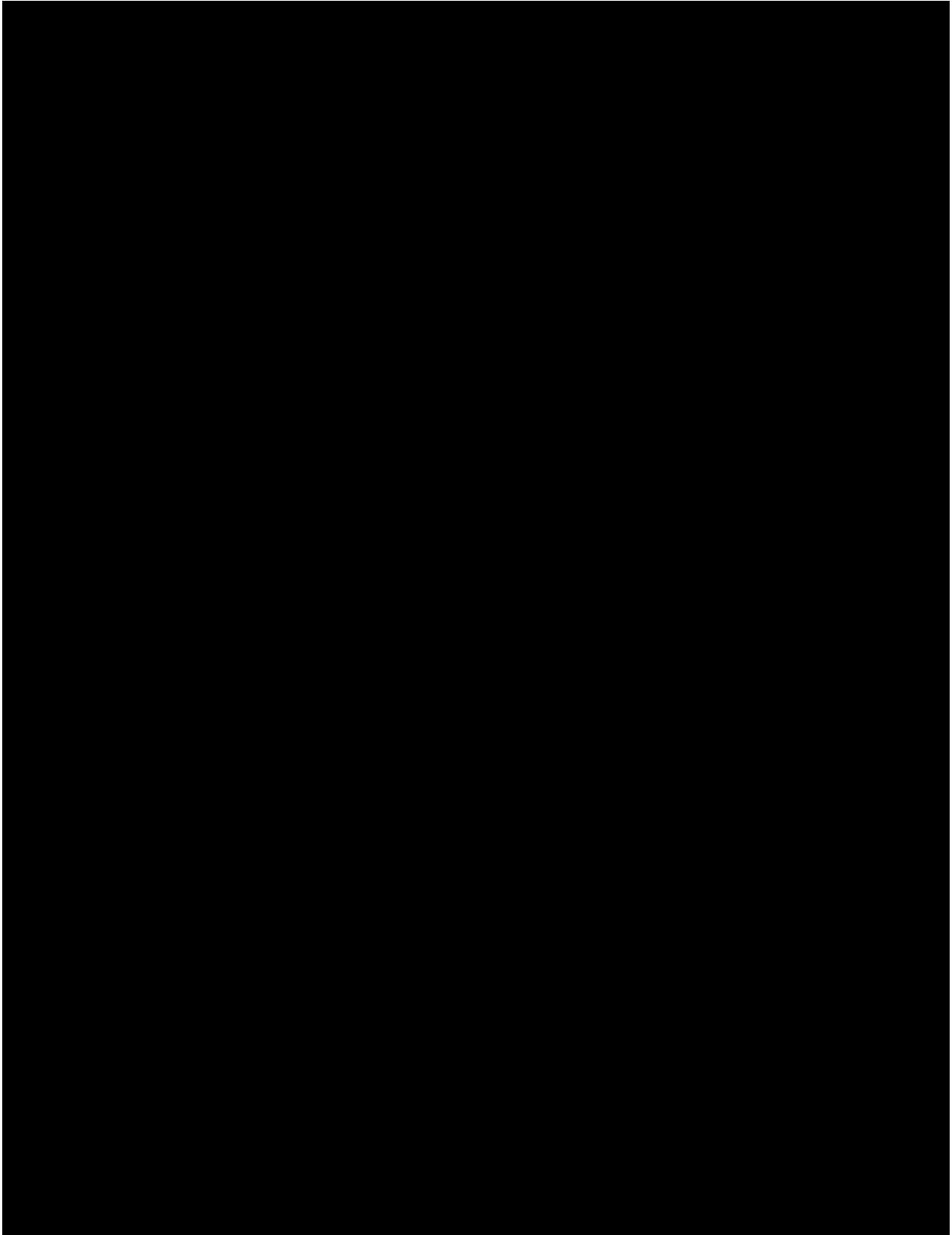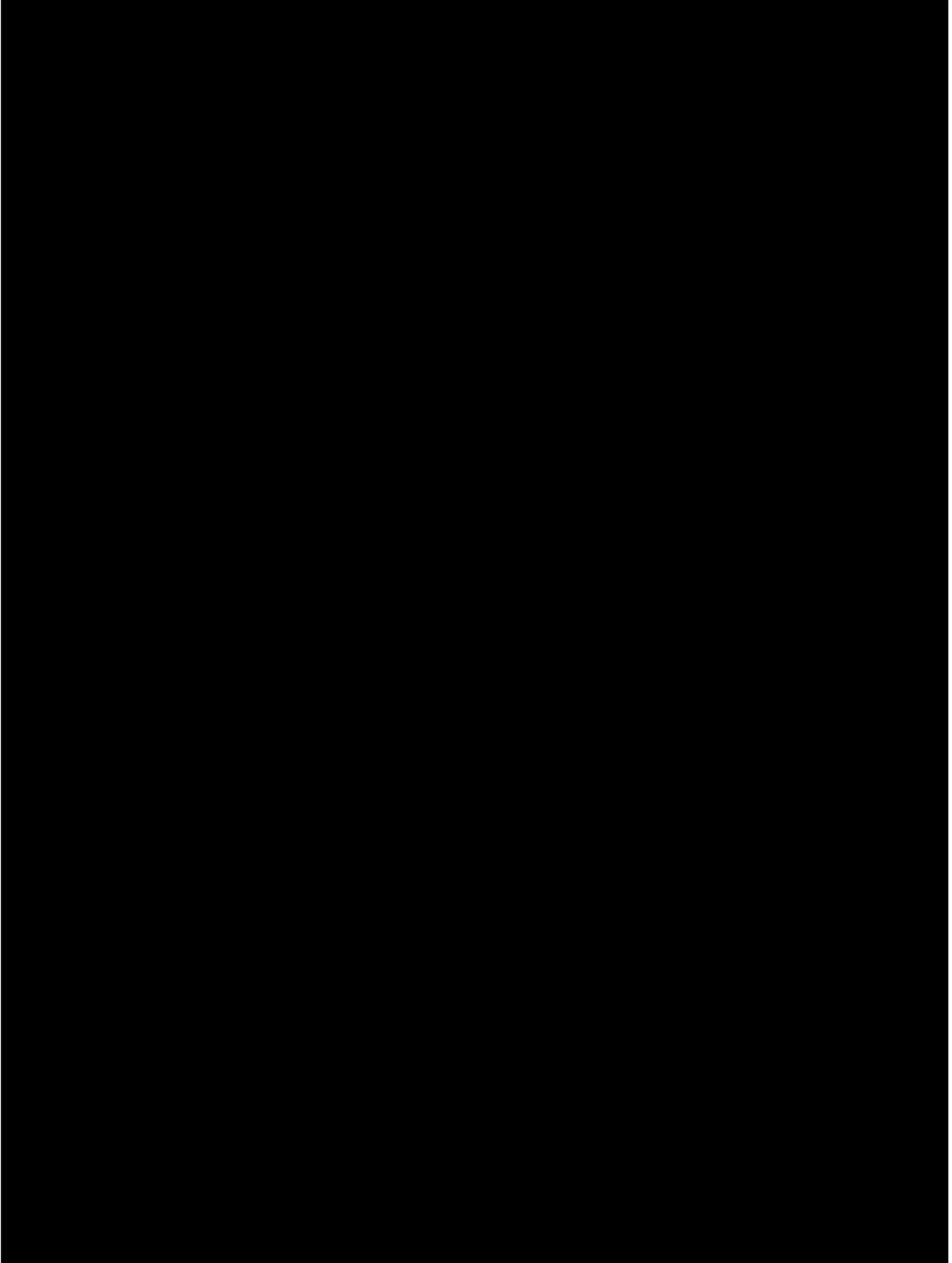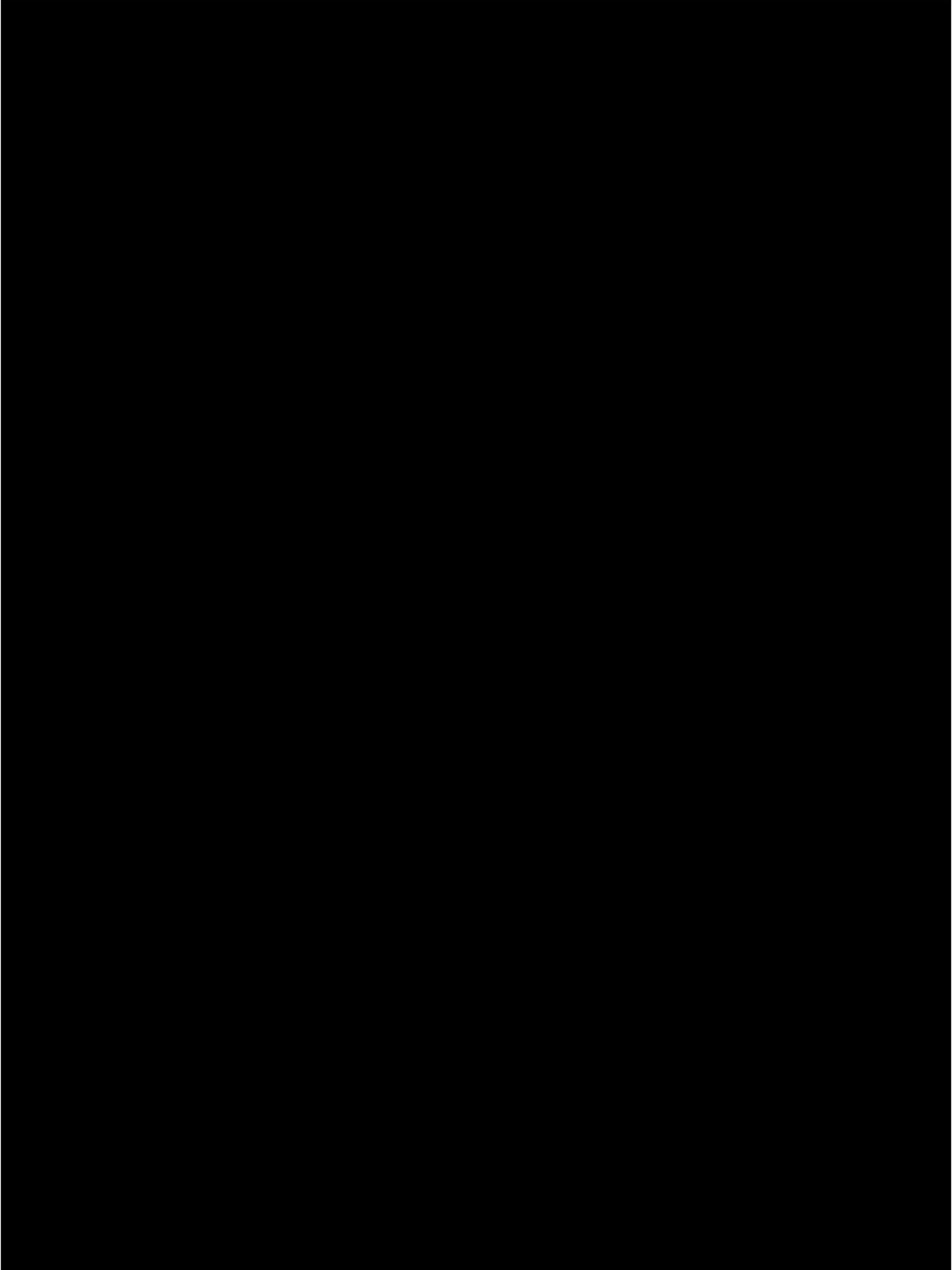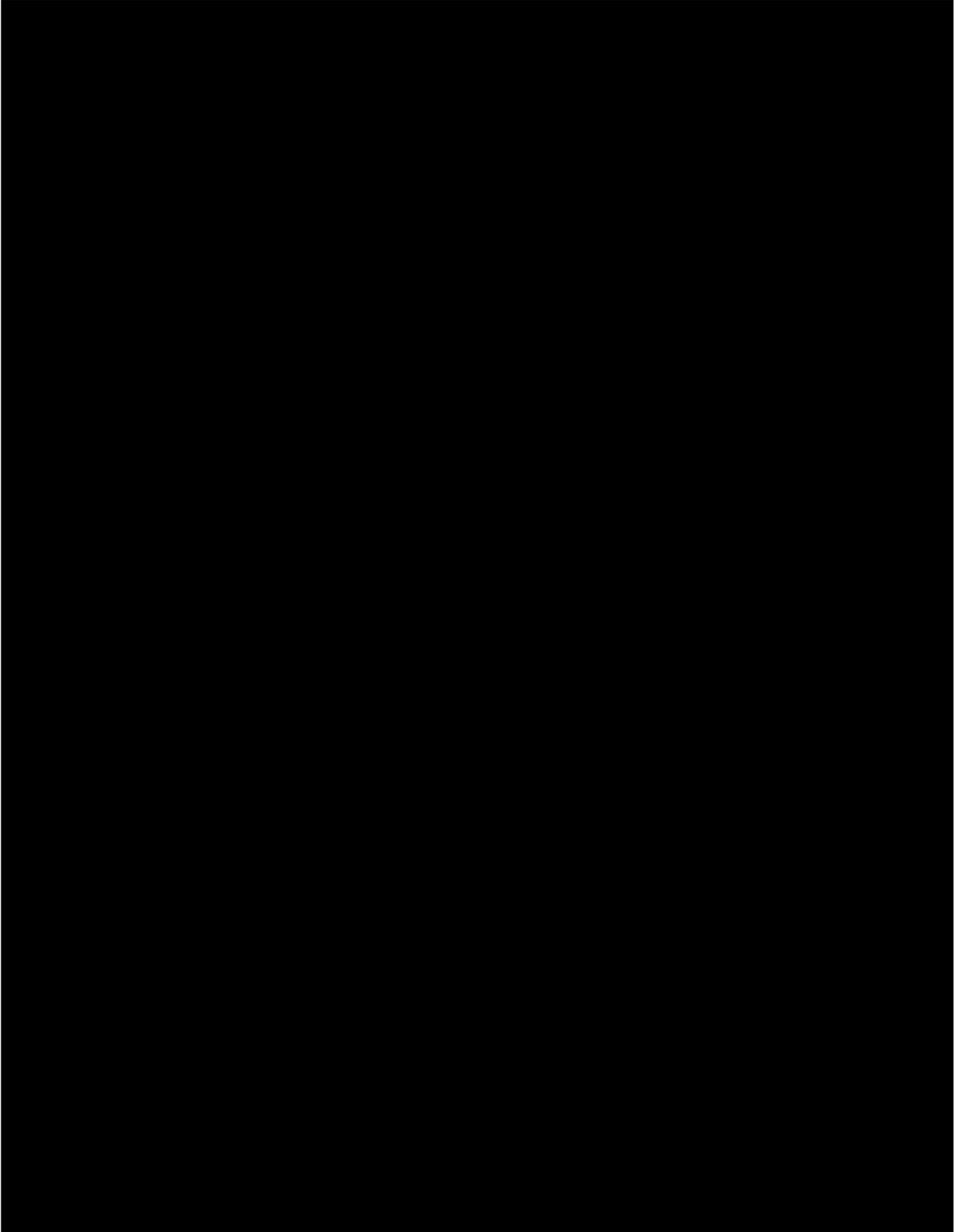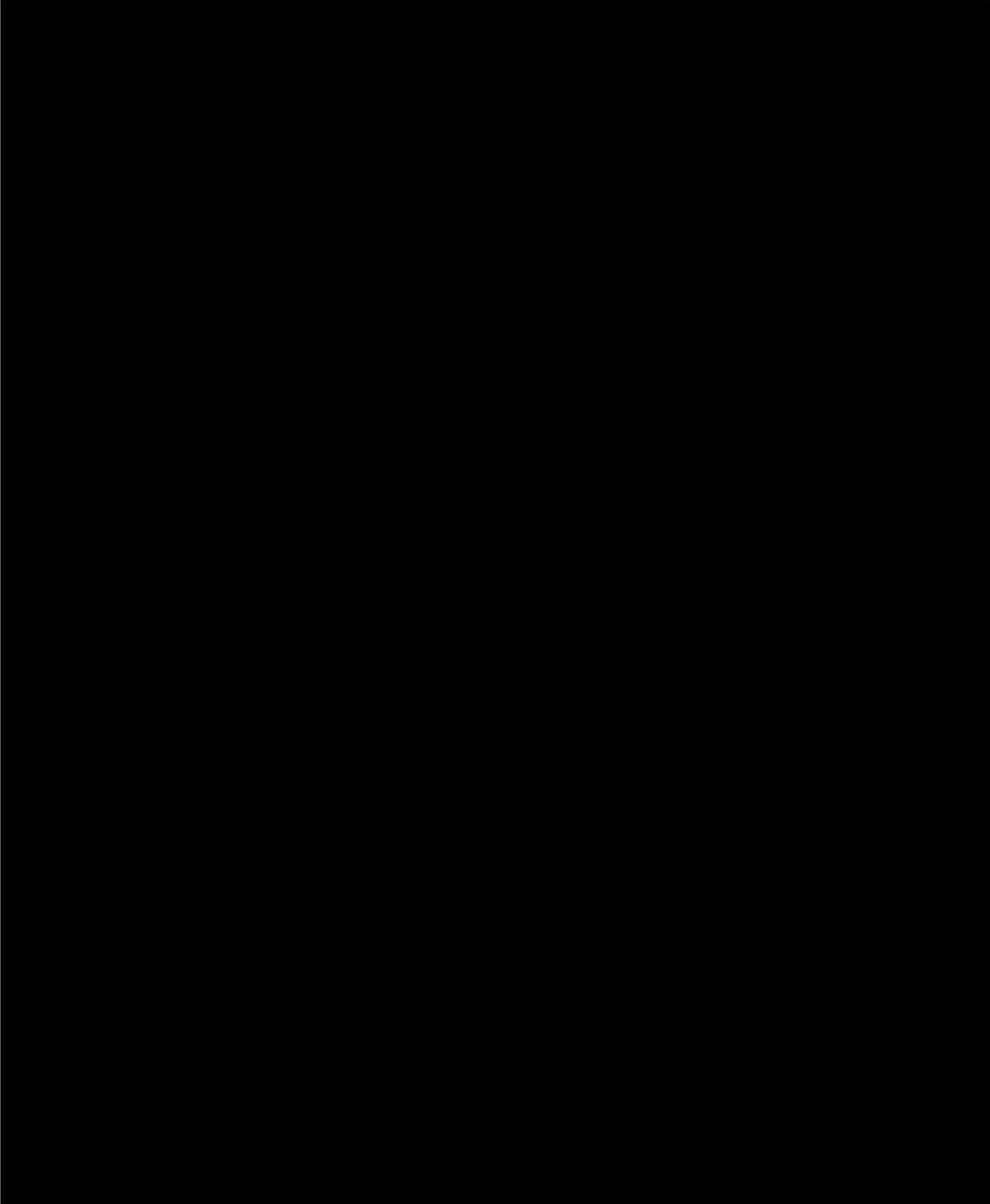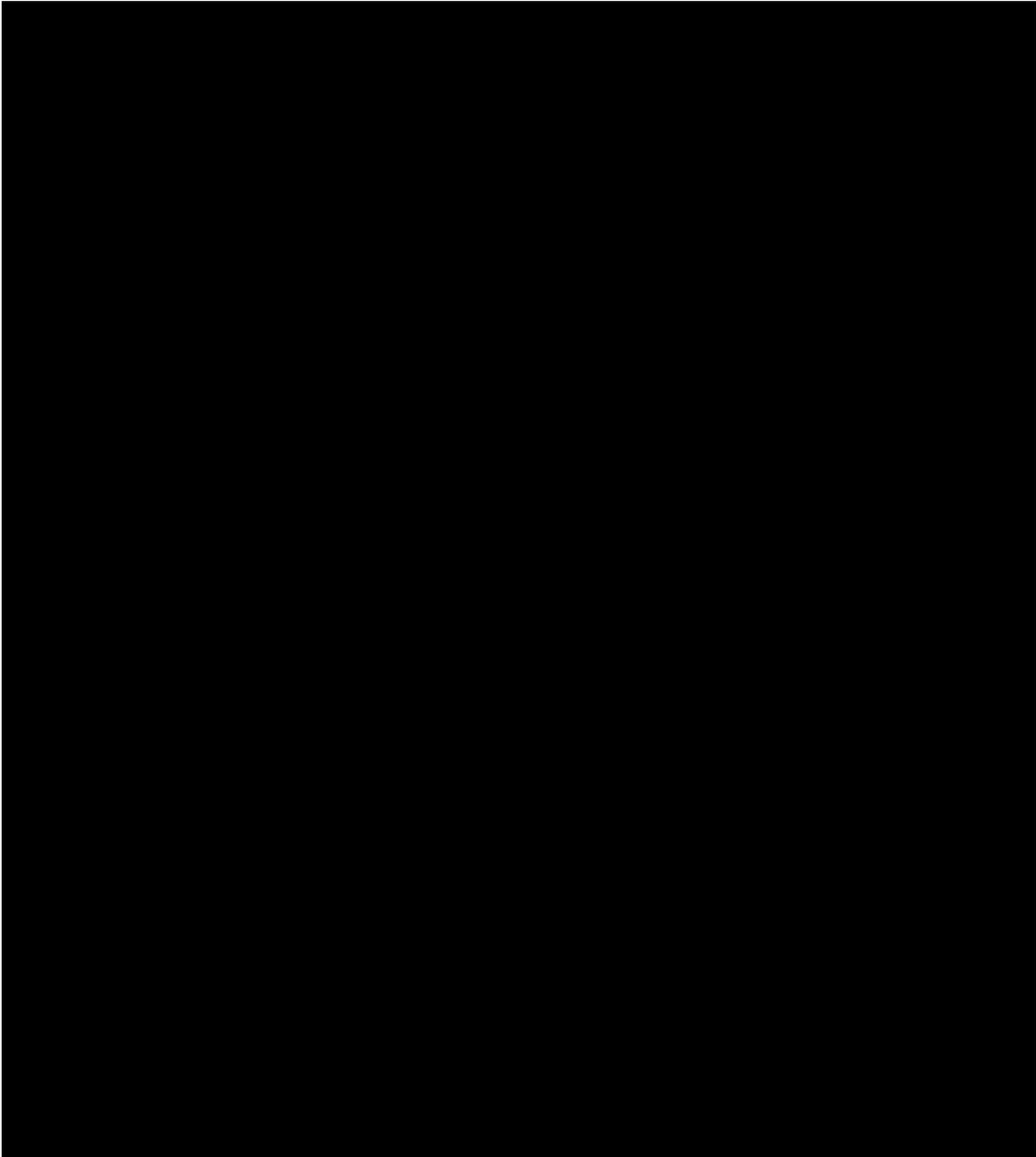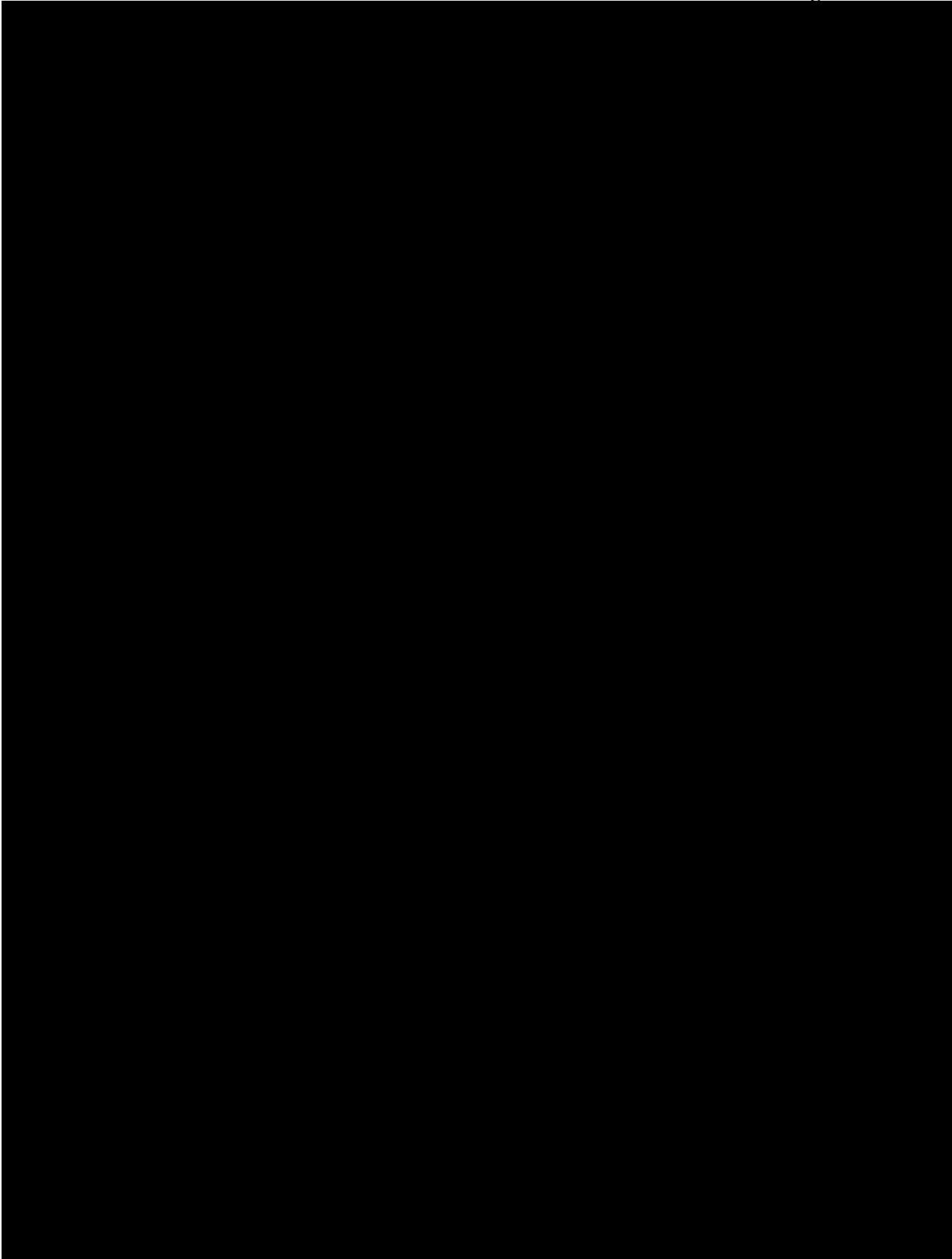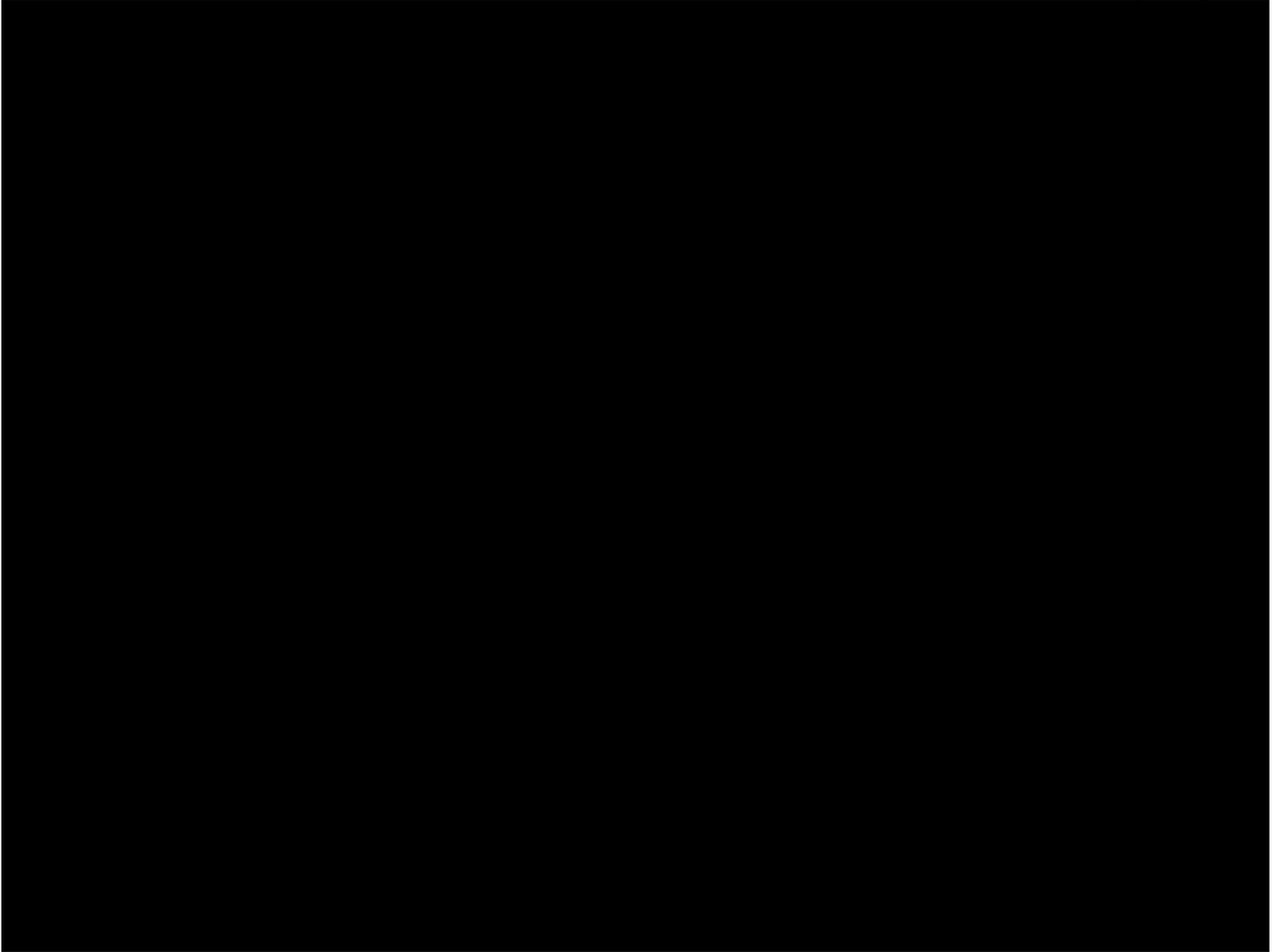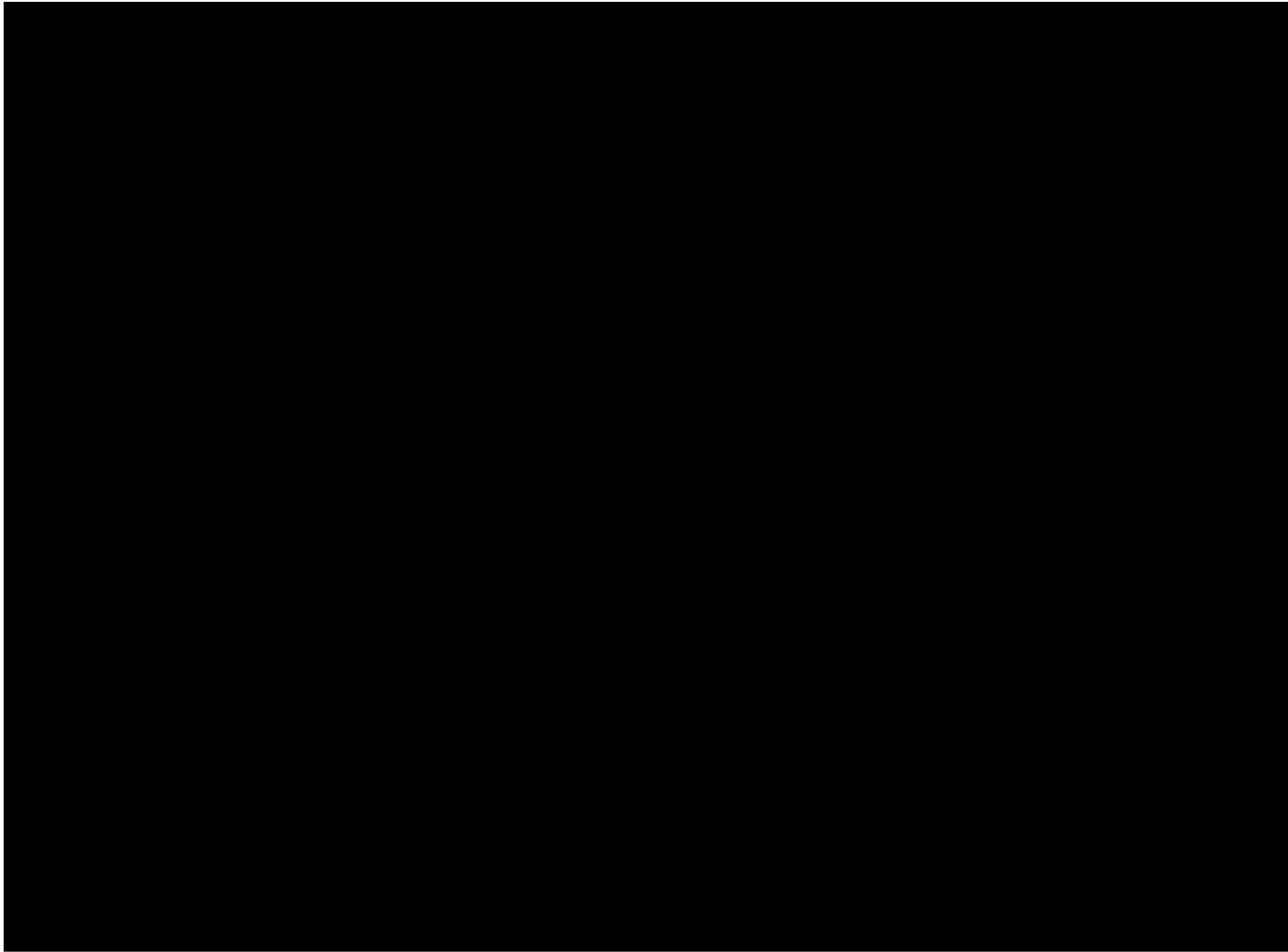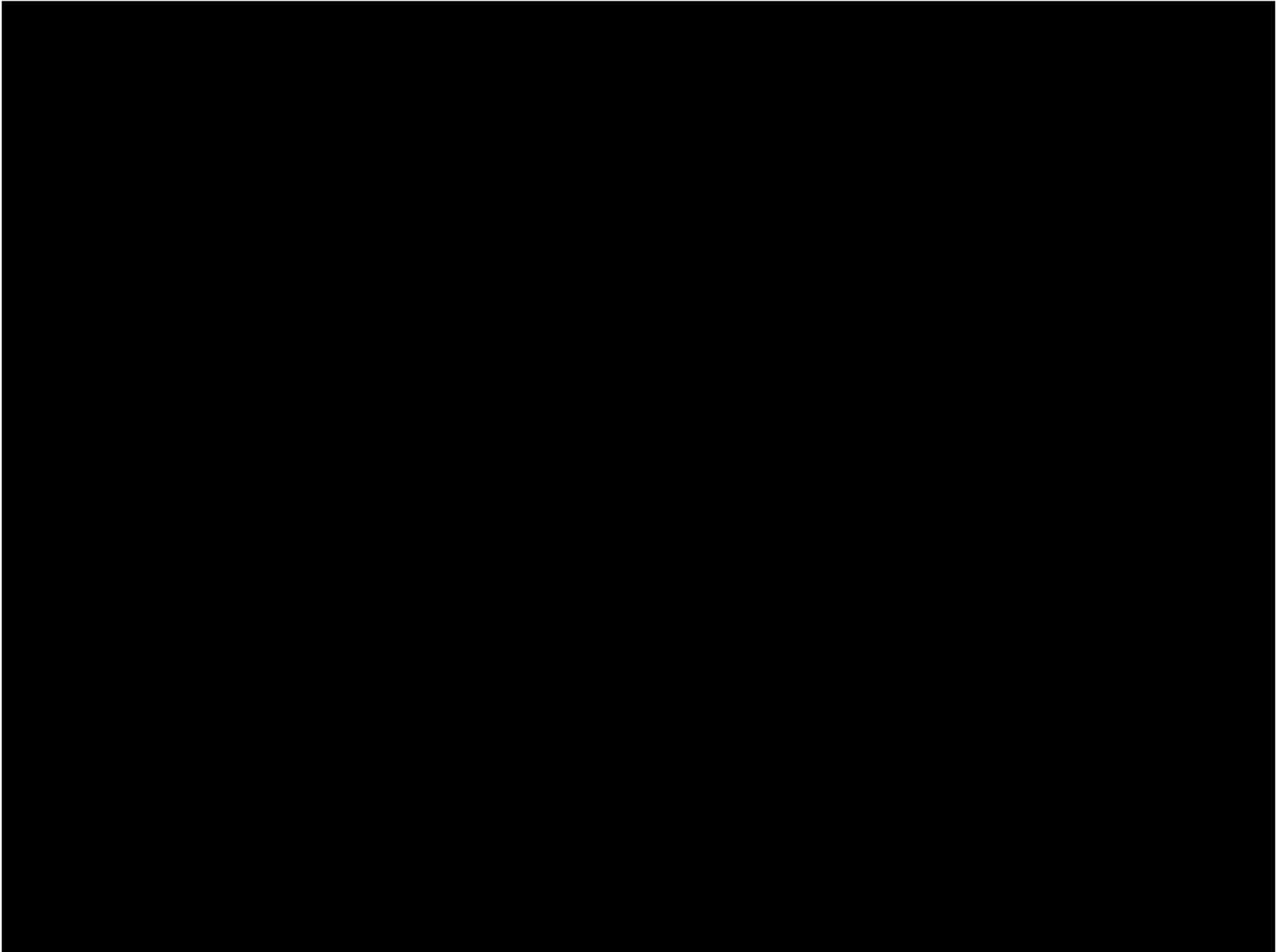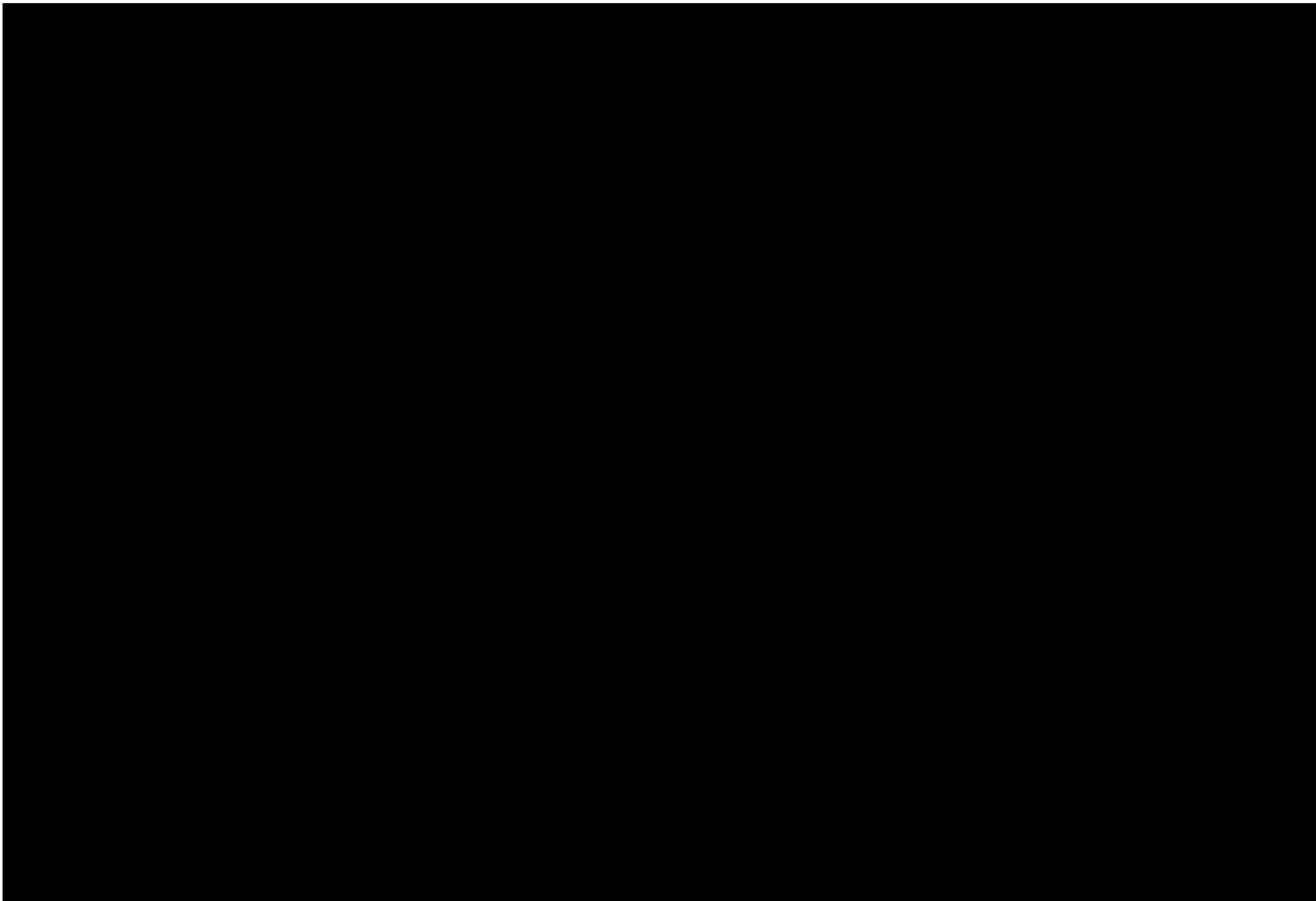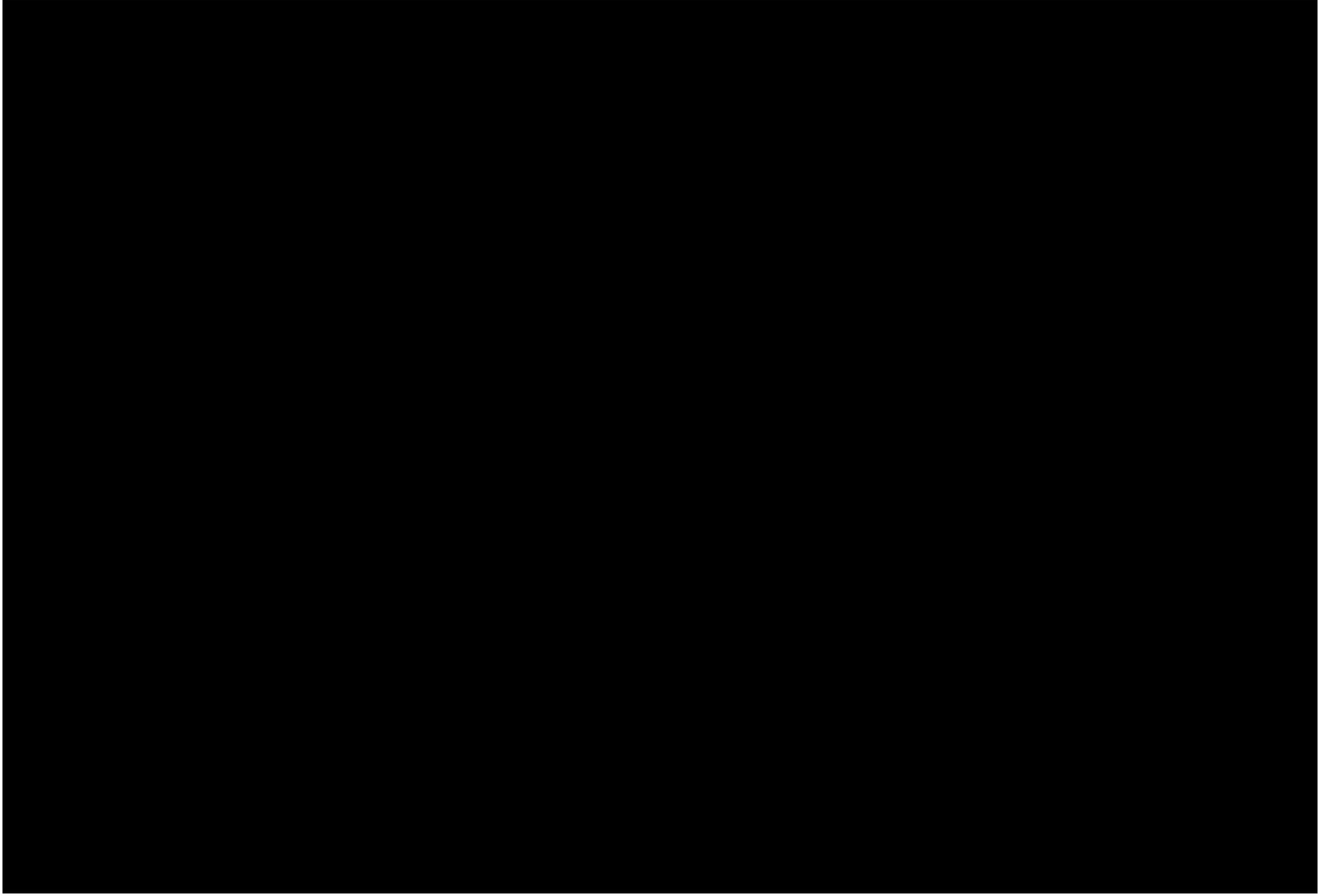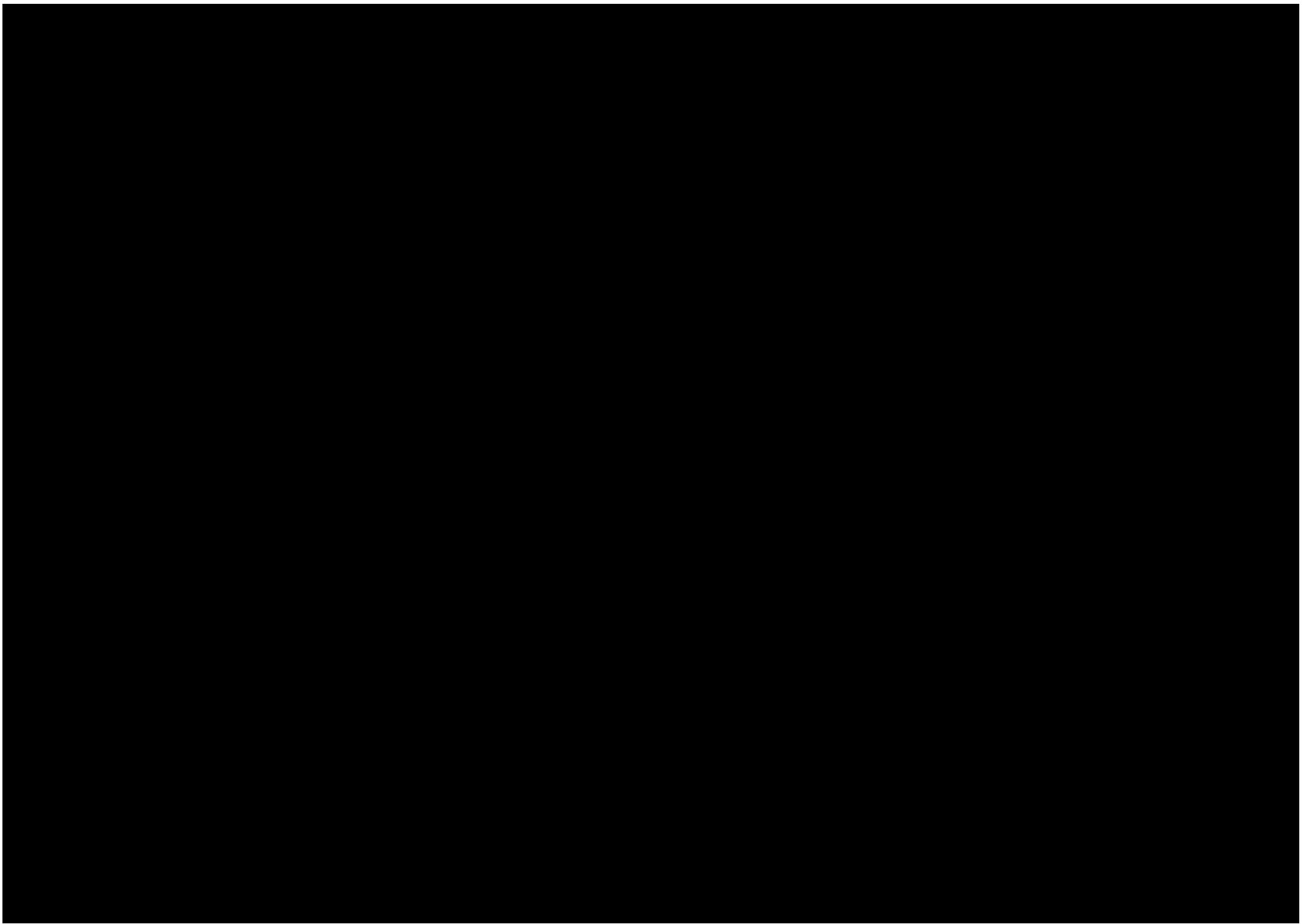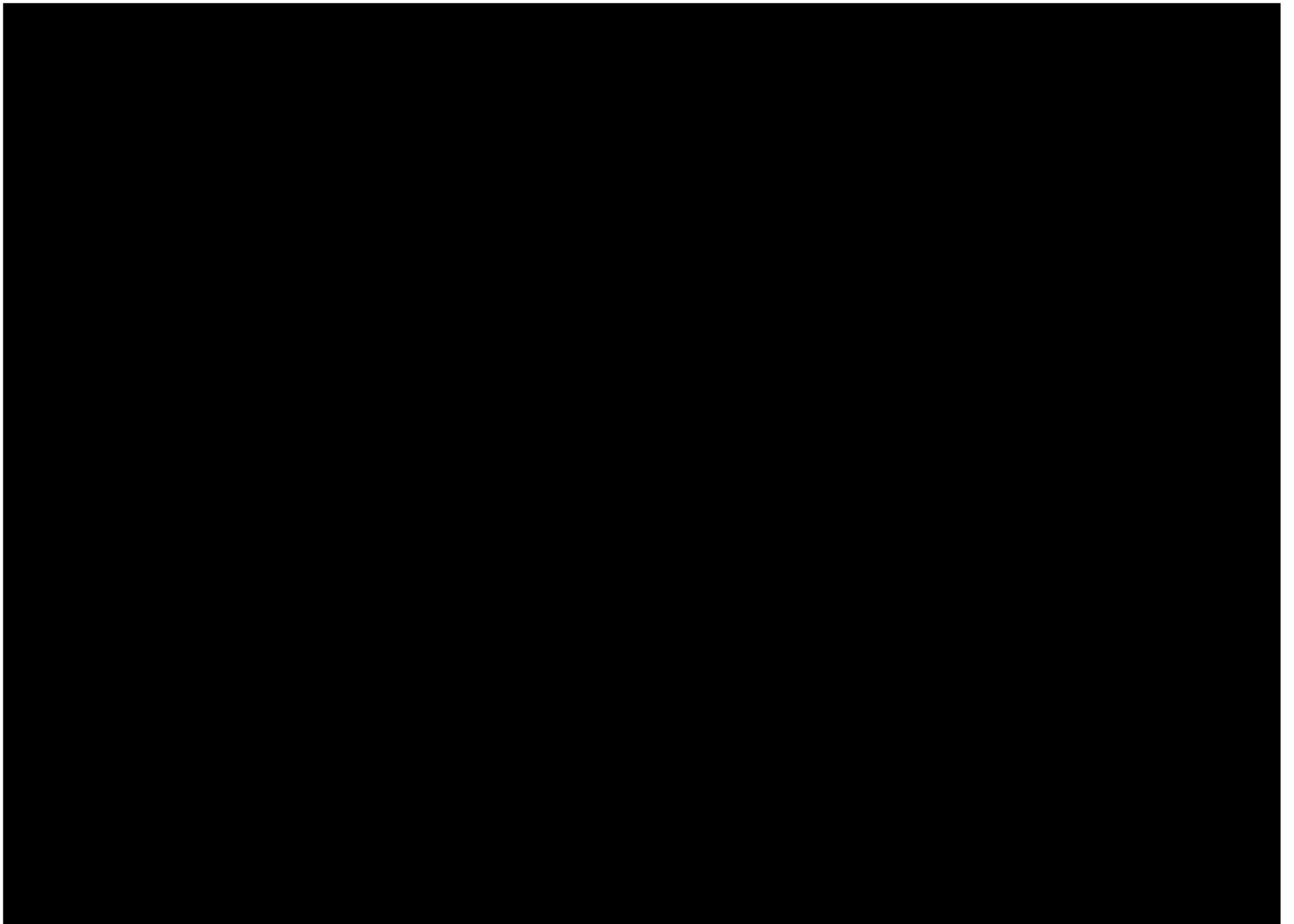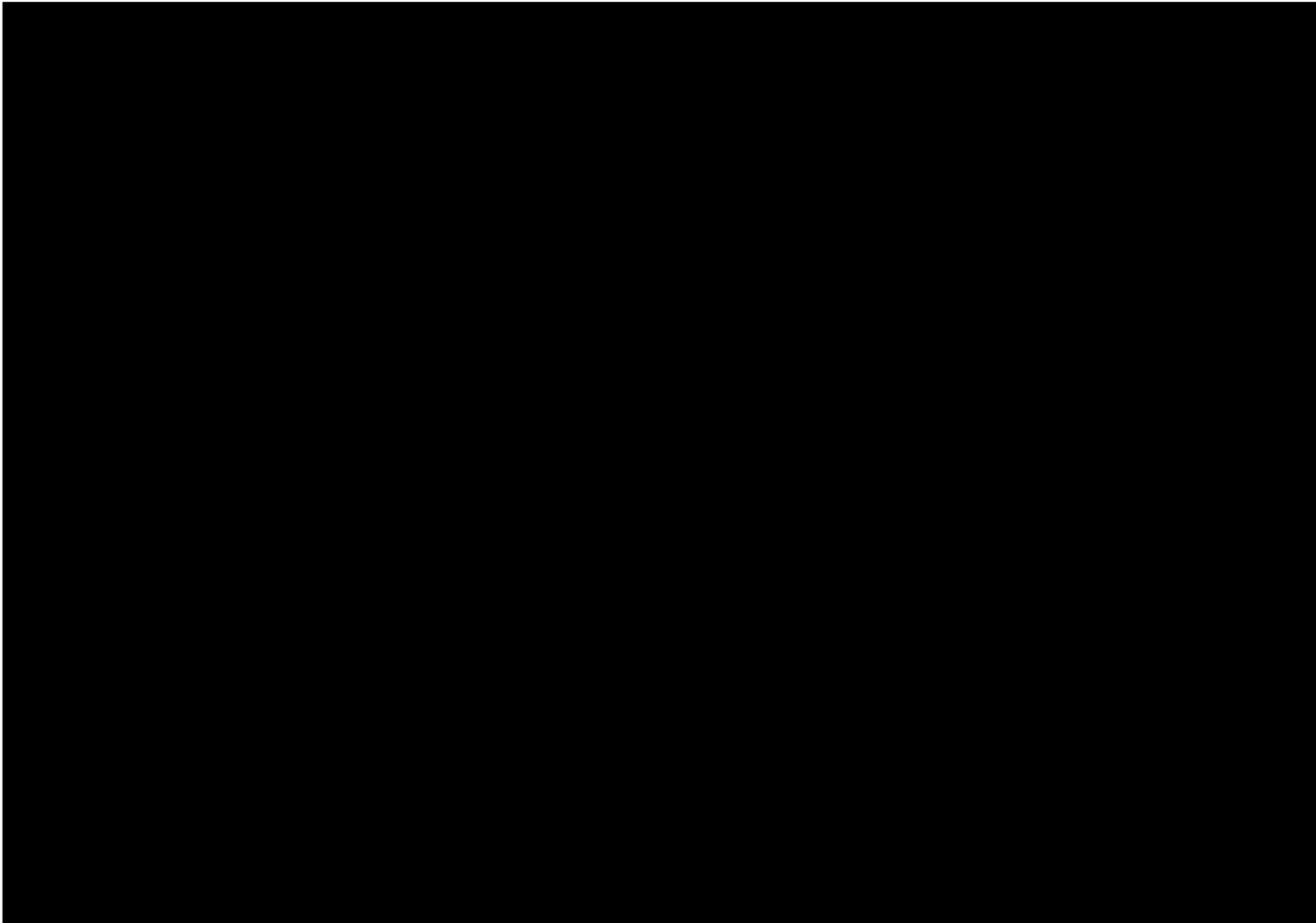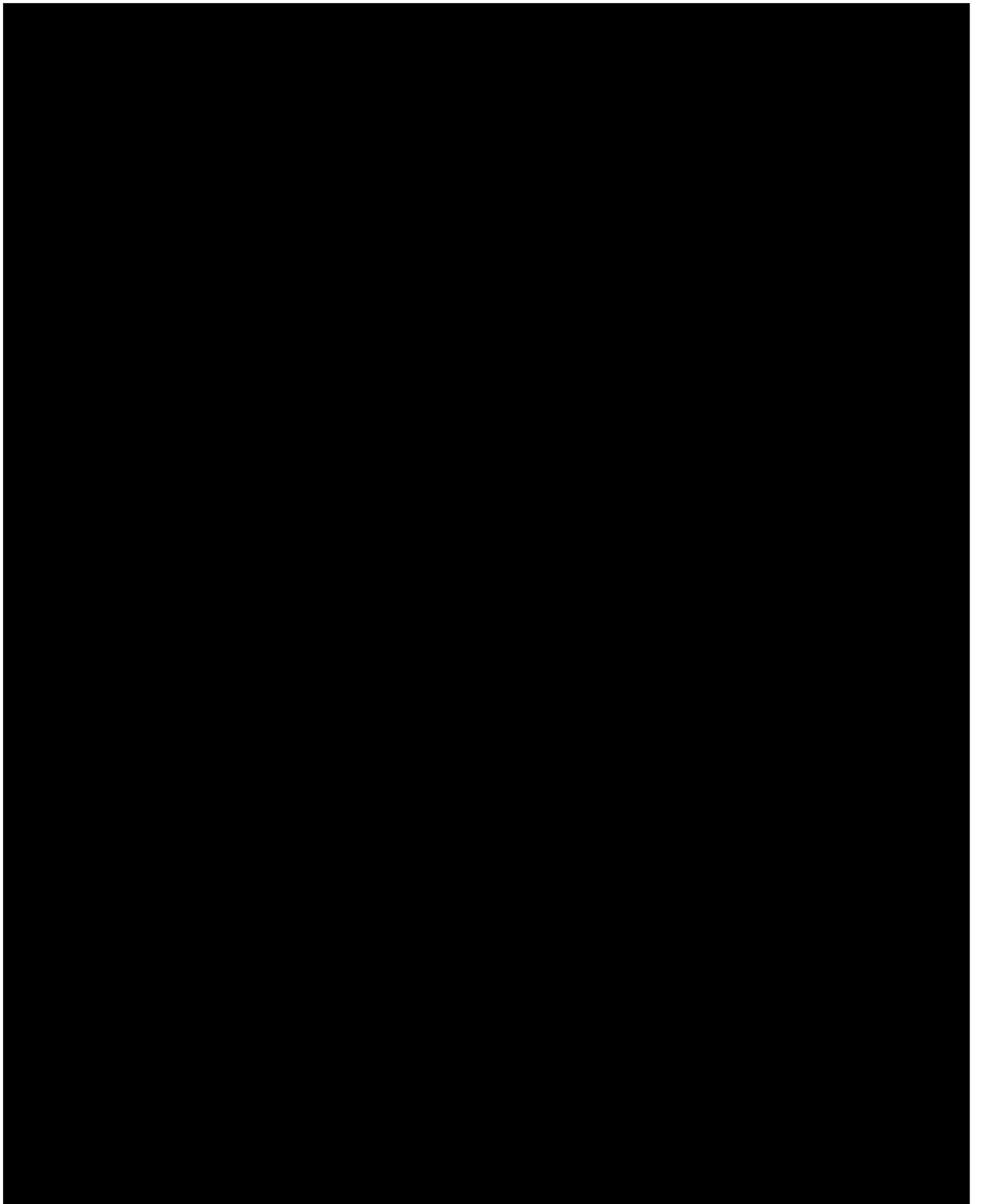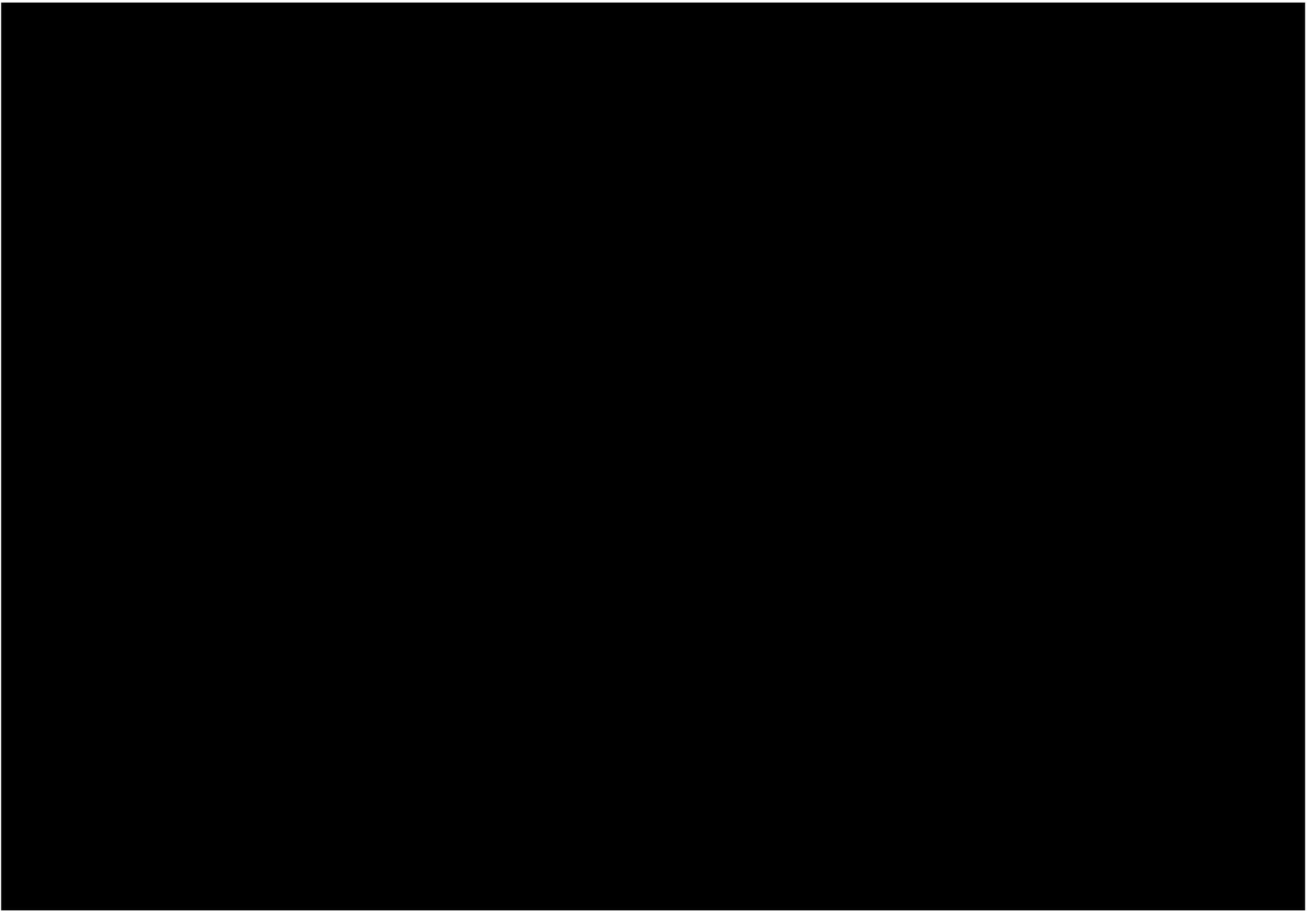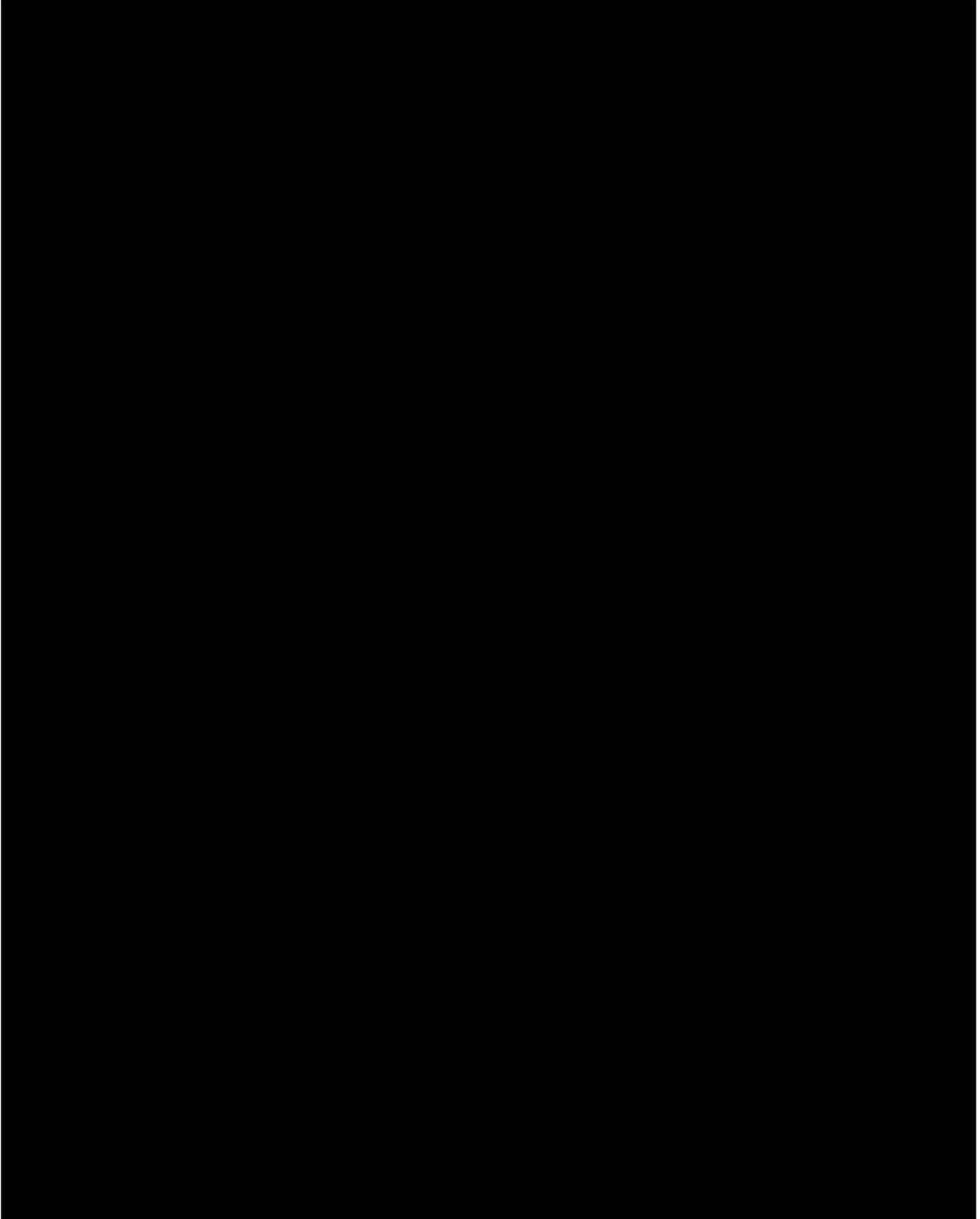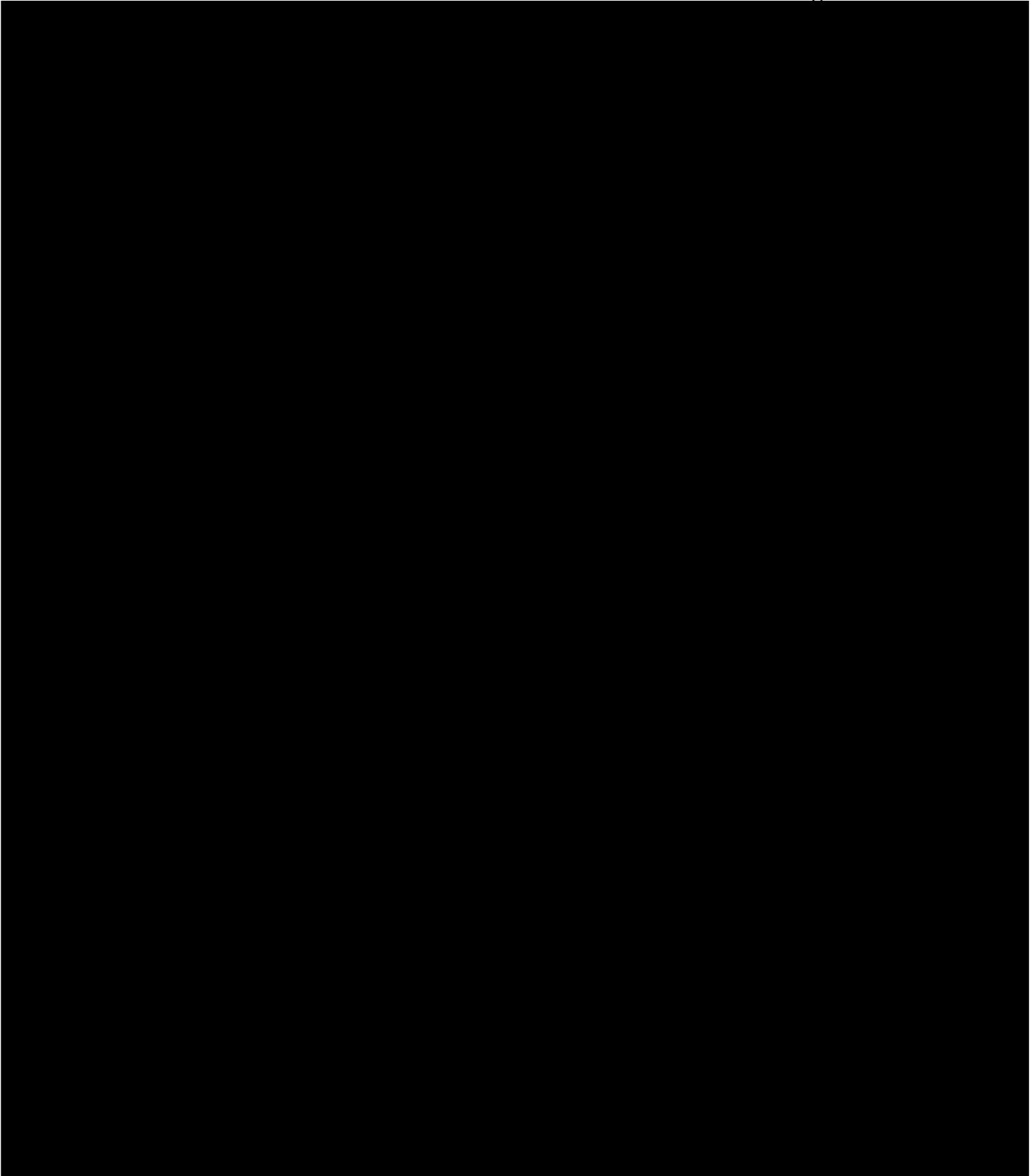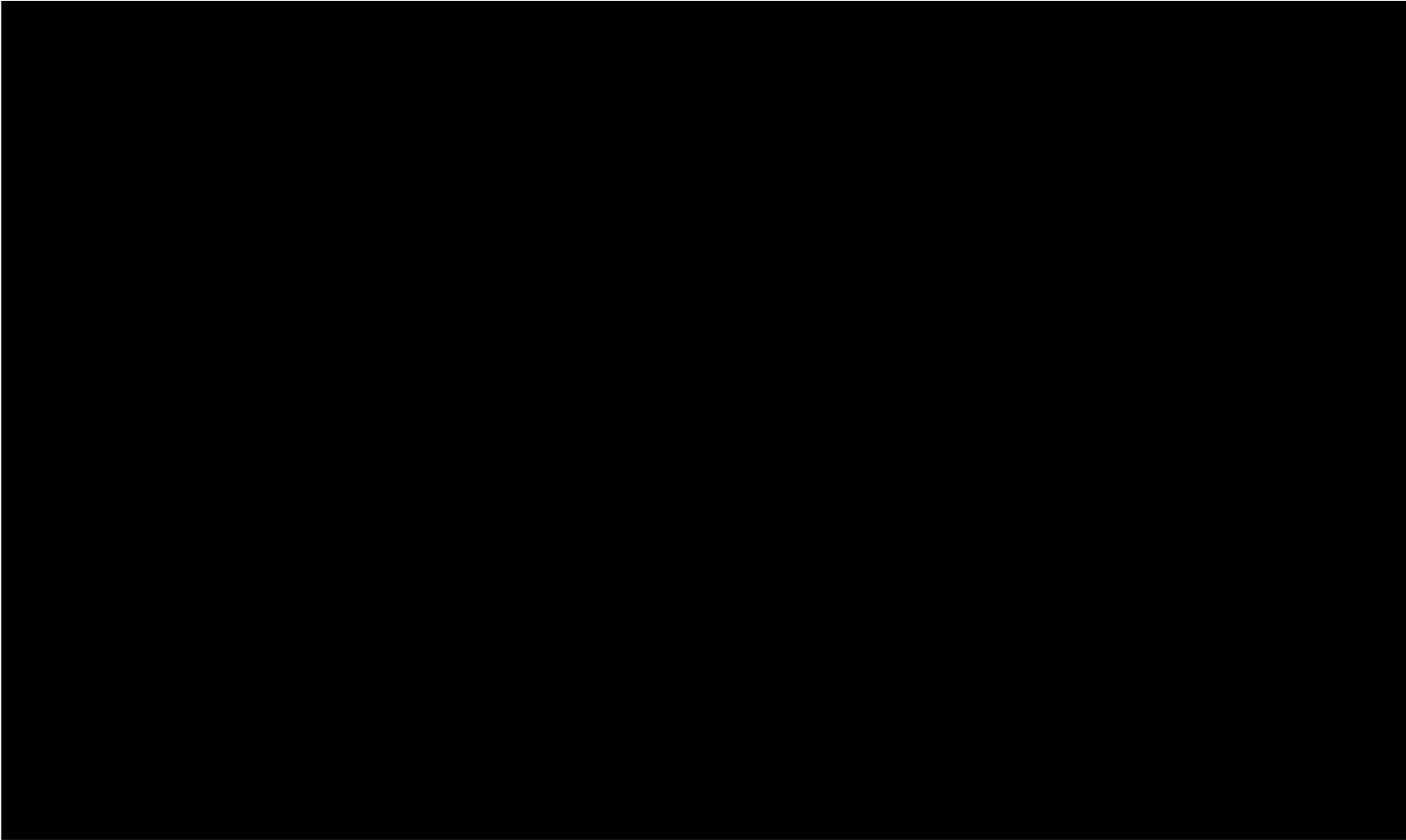
Authorized Investment Proposal for Investment Meeting on: October 26, 2016

Project Name: Environmental Protection Agency's (EPA's) Coal Combustion Residual (CCR) Rule Compliance Program
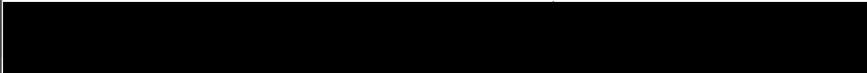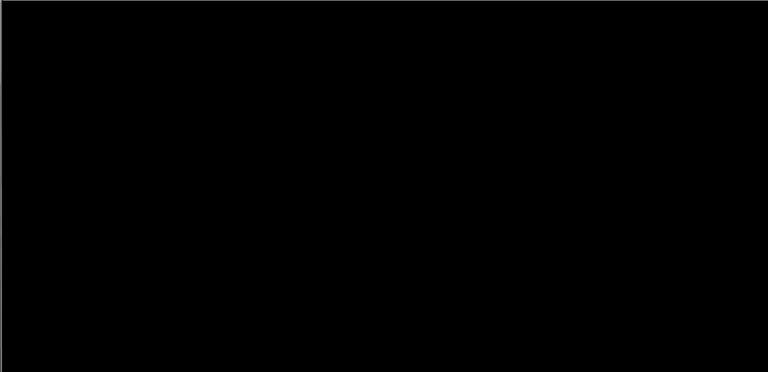
Mill Creek Gypsum Dewatering: $73,303k

Total Sanction Request: $918,853k (net)/$970,071k (gross)
Project Numbers: See list of project numbers on page 5

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Scott Straight/Jeff Heun/Jeff Oeswein/Joe Strickland

Executive Summary

This revised Authorized Investment Proposal (AIP) is seeking full project authorization, under the 2016 ECR Filing, to continue compliance construction and closure activities associated with the project development, conceptual and final design, permitting, closure and construction activities to comply with the EPA's CCR Rule. The final CCR Rule was published on April 17, 2015 and became effective on October 19, 2015.

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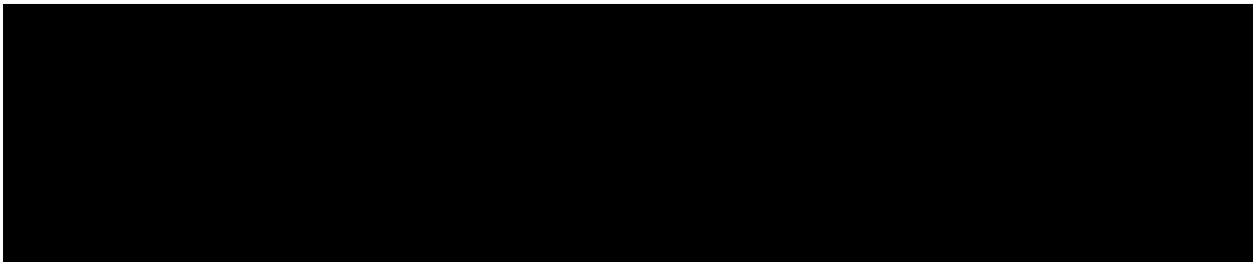
[1] CCR Rule Capital is for new construction activities, not including the Process Water systems that will remain in place and serve the Plants generation needs after compliance with the CCR Rule. An example is new process ponds.

█████ This document also seeks approval for the Mill Creek Gypsum Dewatering project spend for $73,303k. The total amount seeking approval for the CCR Rule Compliance Program and the Mill Creek Gypsum Dewatering is $918,853k (net).

An AIP for $8,500k was submitted on June 30, 2015 to allow engineering, preliminary studies, and compliance construction activities to start in support of the 2016 ECR filing. A revised AIP for $77,462k (net) was approved on February 24, 2016 to provide funding through 2016, prior to approval of the 2016 ECR filing. This requested $918,853k sanction approval is for the total program included in the 2017 BP.

The overall scope of this project includes the design, permitting and final closures of all CCR impoundments at the stations listed above. ████████████████████████████████ ███ ███ ███ ███ While Ghent, Brown and Trimble County stations have new landfill projects which include CCR Treatment (CCRT) scopes for the dewatering and dry handling of CCR, Mill Creek does not. This program also includes the CCRT scopes for Mill Creek consisting of a new gypsum dewatering facility, a new bottom ash dewatering system, and the dry fly ash transport systems that are similar to the CCRT programs at the other stations. ████████████████ ███ ███ ███

Background

As a result of Tennessee Valley Authority's (TVA's) Kingston ash pond failure in 2008, the EPA issued a DRAFT CCR Rule in 2010 to address CCR impoundments. On April 17, 2015, the EPA published the final CCR Rule. The final CCR Rule is based on Subtitle "D" requirements and contained significant changes to the draft CCR Rule. The final CCR Rule requires all CCR storage facilities undergo structural stability, safety factor, and design flood assessments and corrective action by October 17, 2016 to verify they meet minimum standards, as set forth in the rule. In addition, groundwater monitoring must be implemented, and a minimum of eight samples taken within 30 months of the rule being published.

The intent of the CCR Rule is to close all wet CCR Impoundments and move towards dry storage in landfills, which is in line with LG&E and KU's (the "Companies") current long term CCR Storage plans. It is anticipated that closure of Companies CCR storage facilities will be triggered by groundwater monitoring, and would require the facilities to stop receiving CCR 6-months after and to be closed within five years of a groundwater exceedance. It is assumed that closure must start by the first quarter of 2019, based on a groundwater exceedance.

This request is seeking approval of $918,853k for project development, conceptual and final design, permitting, and compliance construction activities. Project development includes the structural stability, safety factor, and design flood assessments for each facility under the CCR Rule. The conceptual design will build on the work completed to date to identify the preferred plan to comply with the CCR Rule and develop a scope of work for final design. Final design will build upon the results of the conceptual design and will allow the Companies to submit the necessary state permits as well as develop construction drawings and specifications for closure activities.

Procurement & Schedule

The structural stability, safety factor and design flood assessment assessments for facilities with potential data gaps (Ghent, Mill Creek, and Trimble County) were completed in 2015, while the remainder of the assessments were completed in 2016. Issues identified during the assessments lead by Generation Engineering were handed off to Project Engineering to implement. The assessments and construction to address the issues must be in progress by October 17, 2016.

Project Engineering has reviewed proposals for the conceptual design, final design, and owner's engineering service to comply with the CCR Rule.
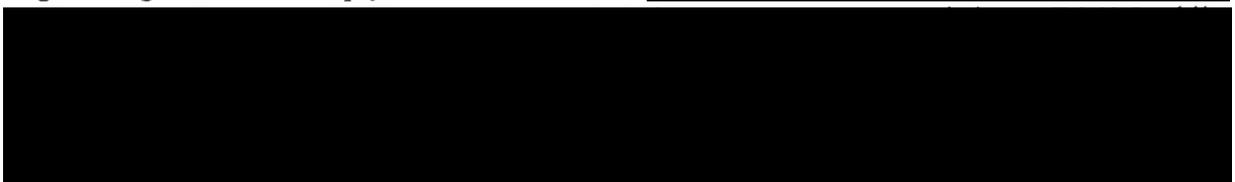
Project Cost

The overall cost to comply with the EPA's CCR Rule utilizing CCR Beneficial Use is $918,853k (net) per the 2017 BP (Table 2), and $73,303k for Mill Creek's gypsum dewatering facility. This revised approval seeks full authorization for project development, conceptual/final design, permitting, and construction activities. Requested authorization per station/project is shown in Table 1.

Other Alternatives Considered

For project development, no alternatives were considered. To meet the regulatory deadlines related to structural stability, safety factor, and design flood assessments, initial studies were

3

completed by the second quarter of 2016 to allow adequate time to implement corrective action by October 17, 2016, or the facility will be forced to begin the closure process.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

Below are the alternatives considered for the projects:
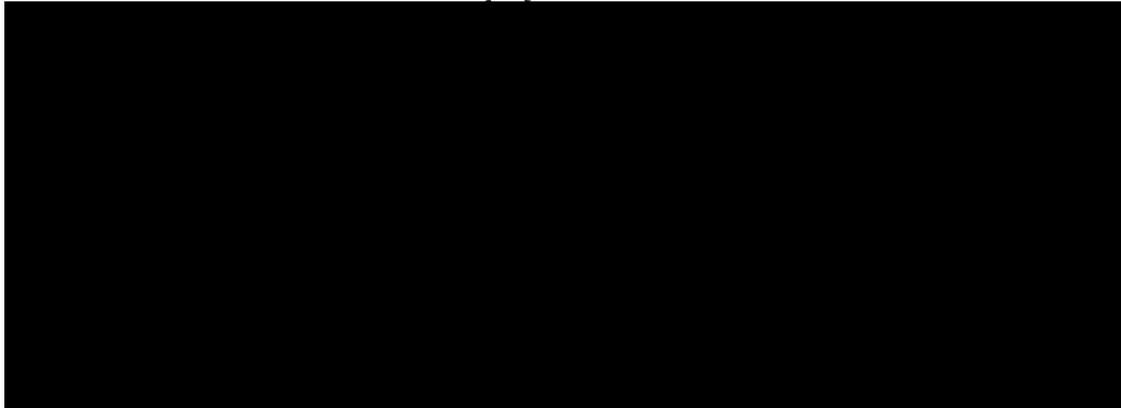
Below are the alternatives considered for the Mill Creek Gypsum Dewatering projects:
1. Recommendation: Mill Creek Gypsum Dewatering   NPVRR: $86,634k
2. Do Nothing: NPVRR: $0

Table 1 below shows a breakout of cost by station and project number for the current authorization request and does not reflect previous authorization request. Cost associated with the previous request will be reallocated to the corresponding new projects:

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[3] CCR Rule Capital is for new construction activities, excluding process water systems, which will remain in place and serve the plants generation needs after compliance with the CCR Rule. An example is new process ponds.
[4] A Do Nothing alternative is not a viable option as this project is a regulatory requirement from the EPA.

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Table 1[5]
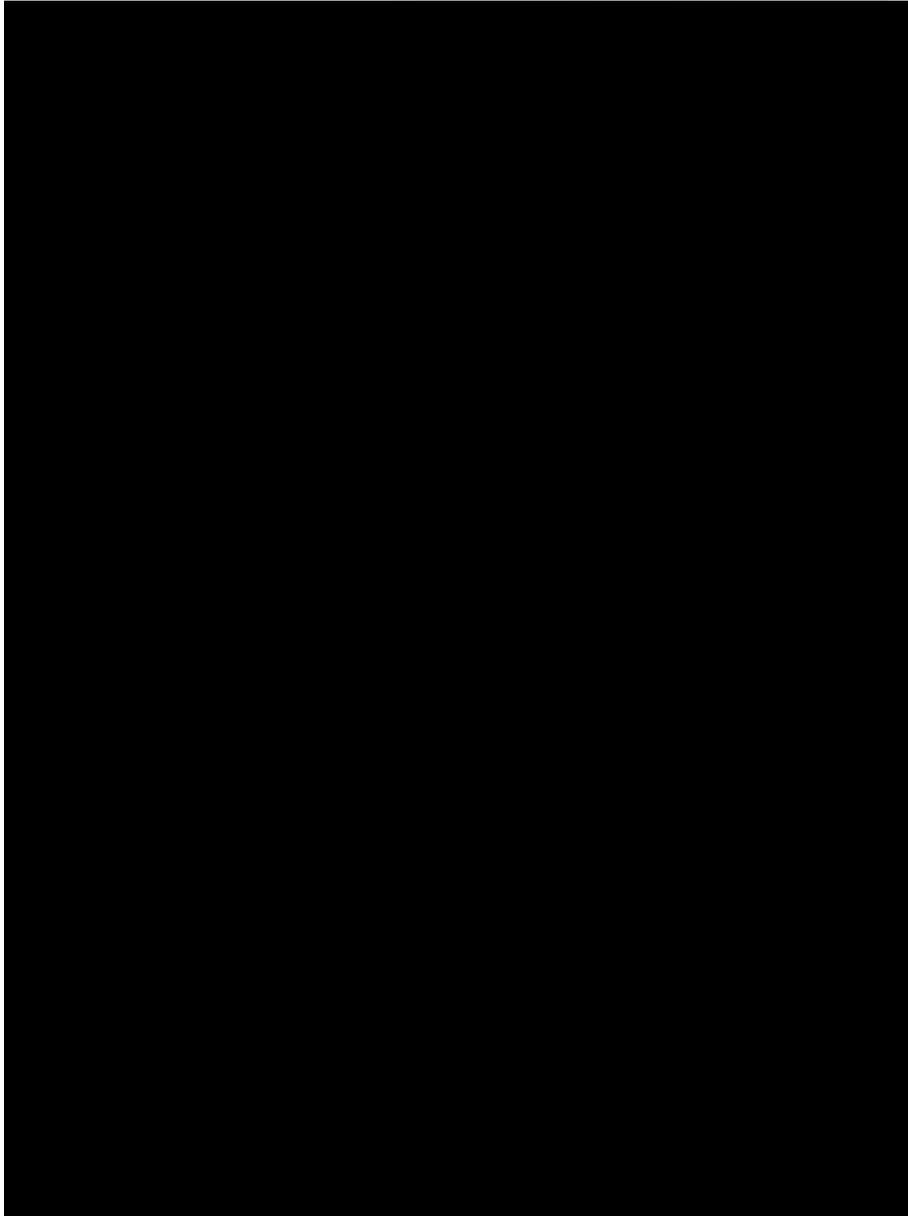
Location	Project #	2017 BP (000's)	2016 ECR Filing (000's)
MC Gypsum Dewatering	152330	$73,303	$0

Table 2 below shows the 2017 Business Plan and 2016 ECR filing costs broken out by year (net):

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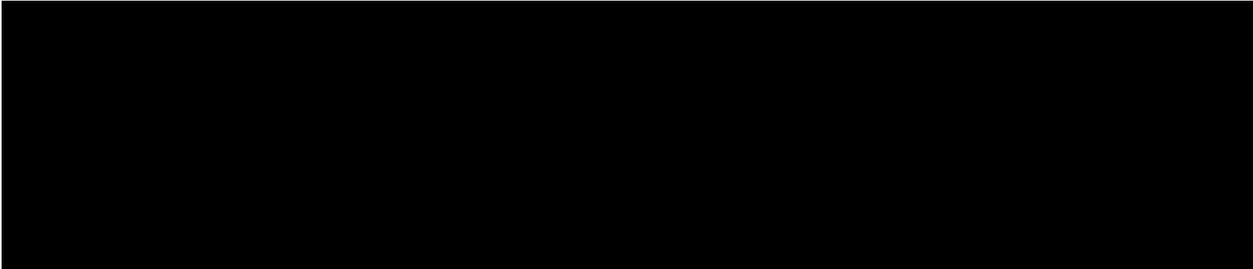
The amounts incurred in Table 2 prior to approval of the 2016 ECR filing were recorded as non-mechanism, all future changes will be mechanism under the approved 2016 ECR filing. Table 3 below shows the 2017 Business Plan and 2016 ECR filing costs broken out by year for the Mill Creek Gypsum Dewatering:

Table 3

$Millions	2016	2017	2018	2019	2020	2021	2022	2023	Totals
2017 BP	$0.3	$28.6	$44.4	$0.0	$0.0	$0.0	$0.0	$0.0	$73.3
2016 ECR	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Variance	($0.3)	($28.6)	($44.4)	$0.0	$0.0	$0.0	$0.0	$0.0	($73.3)

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000's)	Pre-2016	2016	2017	2018	Post 2018	Total
Capital Investment Proposed	-	17,203	152,416	278,207	44,037	491,863
Cost of Removal Proposed	-	26,724	32,476	65,321	302,469	426,990
Total Capital and Removal Proposed	-	43,927	184,892	343,528	346,506	918,853
Capital Investment 2017 BP	-	17,203	152,416	278,207	44,037	491,863
Cost of Removal 2017 BP	-	26,724	32,476	65,321	302,469	426,990
Total Capital and Removal 2017 BP	-	43,927	184,892	343,528	346,506	918,853
Capital Investment variance to BP	-	-	-	-	-	-
Cost of Removal variance to BP	-	-	-	-	-	-
Total Capital and Removal variance to BP	-	-	-	-	-	-

Financial Summary ($000's):

Below is the financial analysis for the project:

Summary ($000)	Project	2016	2017	2018	2019	2020	2016-2059
Project Net Income	MC Gypsum Dewatering	$0	$1,484	$3,518	$3,312	$3,449	$56,298
Project ROE							
	MC Gypsum Dewatering	0.0%	9.6%	9.4%	9.2%	9.6%	9.9%

Environmental Risks:

There are no environmental risks related to New Source Review associated with this project.

Conclusions and Recommendation

It is recommended that this revised Authorized Investment Proposal be approved to provide full funding, per the 2017 BP and in concert with the 2016 ECR Filing, in the amount of $918,853k (net) as outlined in the 2017 BP. Work under this authorization includes, Project Development, Conceptual and final design, permitting and construction activities for the EPA's CCR Rule compliance program impoundment closure activities, new CCR Rule related process water systems, and Mill Creek's gypsum dewatering, bottom ash and dry fly ash handling systems.

_____
Kent W. Blake
Chief Financial Officer

_____
Victor A. Staffieri
Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: 1/31/2018

Project Name : East End Reinforcement (Aiken Road HP Distribution Pipeline)

Total Approved Expenditures: $2,044k (Approved on 06/28/2017 for preliminary design)

Total Revised Expenditures: $8,176k (Including $743k in contingency)

Project Number(s): 152546

Business Unit/Line of Business: GDO/Gas Operations

Prepared/Presented By: Brian Lenhart/Tom Rieth

Executive Summary

The Crestwood/Simpsonville medium pressure gas distribution system currently operates at 55 psig, has a maximum allowable operating pressure (MAOP) of 60 and covers the mid-eastern portion of Jefferson County, including Anchorage, Crestwood, Eastwood, Simpsonville, and Pewee Valley, as well as portions of Oldham County and Shelby County. The system is constrained by small diameter trunk lines, location barriers such as Floyd's Fork and Interstate 64, lack of additional gas supply points, and consistent residential growth away from the only sources of gas supply. The system has already experienced growth away from the sources of gas supply, and the existing infrastructure is no longer conducive to supporting new development. In order to serve its current and future loads, it has been determined that reinforcements are necessary. This project will improve reliability for existing customers as well as support future growth in the area by installing a new 8-inch steel high pressure distribution pipeline which will add a new supply of gas to the most constrained portion of the system.

The project was previously authorized for $2,044k in June 2017 for survey, engineering, and design activities necessary to develop construction bid documents as well as real estate and right-of-way activities necessary for construction of the new pipeline and completing a 3,480-foot section of pipeline cojointly with the installation of 6-inch plastic extension to serve the new "Villas of Floyd's Fork" development. 2017 actual spend was $1,189k. The lower spend was attributed to timing for survey, engineering, and right-of-way activities, which also impacted the amount of the 3,480-foot of construction completed. The project team is now requesting approval for the full project, at $8,176k. An additional $6,132k of authorization is requested to complete final engineering and design efforts, real estate and right-of-way acquisition, material purchasing, and pipeline construction labor necessary to complete installation of the new pipeline.

The 2018 Business Plan (BP) included $5,148k in 2018, which was based on the June 2017 authorization of $2,044k for 2017. Based the actual 2017 spend and estimated increase

additional 2018 funding of $1,839k was approved through the Corporate RAC process in February 2018.

Background

The Crestwood/Simpsonville medium pressure gas distribution system covers the mid-eastern portion of Jefferson County, including Anchorage, Crestwood, Eastwood, Simpsonville, and Pewee Valley, as well as portions of Oldham County and Shelby County, is primarily supplied by eight regulator facilities from both the Eastern Kentucky and Crestwood high pressure distribution pipelines. The area has been experiencing consistent residential growth away from any strong sources of gas supply, particularly in Norton Commons, Flat Rock Ridge, and Brookfield. The neighborhoods of Polo Fields and Persimmon Ridge represent the bulk of the existing constrained system, and currently have the lowest pressure points in the Crestwood/Simpsonville distribution system.

Gas Engineering has investigated several pipeline routes and connection locations in order to determine the most efficient and cost effective solution for reinforcement to this system. Routes evaluated include:

1. Installation of 3.0 miles of 8-inch high pressure gas main from the existing Eastern Kentucky high pressure distribution pipeline along Aiken Road, starting at the intersection of Old Henry Road and Bush Farm Road and continuing to the intersection of Aiken Road and Flat Rock Road, where the pipeline will terminate at a new medium pressure regulator facility. An additional new medium pressure regulator facility will be installed near the intersection of Aiken Road and Johnson Road to support new development off Johnson Road.

2. Installation of 3.2 miles of 4-inch high pressure gas main from the existing Crestwood high pressure distribution pipeline along Floydsburg Road, starting near the intersection of Abbott Lane and Myers Ave and continuing to the intersection of Floydsburg Road and Aiken Road, where it will terminate at a new medium pressure regulator facility.

   This reinforcement option requires the installation of 1.3 miles of 6-inch medium pressure pipeline along Johnson Road, starting at the intersection of Flat Rock Road and Aiken Road and ending at the intersection of Johnson Road and Aiken Road.

3. Installation of 3.2 miles of 4-inch high pressure gas main from the existing Crestwood high pressure distribution pipeline along Floydsburg Road, starting near the intersection of Abbott Lane and Myers Ave and continuing to the intersection of Floydsburg Road and Aiken Road, where it will terminate at a new medium pressure regulator facility.

   This reinforcement option requires the installation of two additional pipelines, the first of which includes 4.7 miles of 6-inch medium pressure pipeline along Long Run Road, starting at the intersection of Floydsburg Road and Aiken Road and ending at the intersection of Long Run Road and Shelbyville Road. The second pipeline includes

extending the existing 8-inch high pressure distribution pipeline at Connor Station through Colt Run Road 2.8 miles to Long Run Road, where it will terminate at a new medium pressure regulator facility.

Following completion of this project, the gas system will have the available capacity to continue to reliably serve customers on the Crestwood/Simpsonville system and provide additional supply for future residential growth.

Alternatives Considered

- Recommendation: NPVRR: $10,127k

    Install 3.0 miles of 8" high pressure distribution pipeline along Aiken Road.

    This option provides the benefit of improving reliability of the existing Crestwood/Simpsonville medium pressure distribution as well as providing additional gas supply to serve future residential growth. The estimated capital cost is $8,176k.

- Alternative #1:   NPVRR: $10,890k
    Install 3.2 miles 4" high pressure distribution pipeline along Floydsburg Road and a new 1.3 mile, 6" medium pressure distribution pipeline along Johnson Road.

    The route from the Crestwood high pressure distribution pipeline does not provide additional benefits to the recommendation and requires the installation of additional medium pressure distribution facilities. Additionally, detailed engineering and design efforts to identify project risks have not been completed for this alternative. As such, this alternative is not recommended. The estimated capital cost is $8,799k.

- Alternative #2:   NPVRR: $13,213k

    Install 3.2 miles of 4" high pressure distribution pipeline along Floydsburg Road, as well as extending the existing 8" high pressure distribution pipeline at Connor Station and Colt Run Road 2.8 miles to Long Run Road and a new 4.7 mile, 6" medium pressure pipeline along Long Run Road.

    The route from the Crestwood high pressure distribution pipeline does not provide additional benefits to the recommendation and requires the installation of additional high pressure distribution and medium pressure distribution facilities. Additionally, detailed engineering and design efforts to identify project risks have not been completed for this alternative. As such, this alternative is not recommended. The estimated capital cost is $10,696k.

Compliance

The materials and construction activities will be done in a manner compliant with State and Federal Regulations, and Company procedures and construction standards. Materials not

ordered on the current pipe, valve and fitting supplier will be specified to meet requirements of **Although** 49 CFR 192. Operator Qualification (OQ) tasks for the project will be specified in RFP documents for contractor construction work on the project. Applicable company procedures will be communicated to (accessible by) the contractor via hardcopy and regular progress update meetings. Recommended contractors will maintain an OQ plan approved by the Gas Safety and Technical Training department and will use the ████████████████████████ system to document on-going compliance.

Project Description

- **Project Scope and Timeline**
  The scope of this project includes installing approximately 3 miles of 8-inch, epoxy coated, steel pipeline with an MAOP of 200 psig from the Eastern Kentucky Pipeline near the intersection of Old Henry Road and Bush Farm Road to the intersection of Aiken Road and Flat Rock Road. Two new regulation facilities will be required to reduce the line pressure to the MAOP of the existing Crestwood/Simpsonville medium pressure distribution system; one at the intersection of Aiken Road and Johnson Road, and the second at the termination of the new high pressure distribution pipeline near the intersection of Aiken Road and Flat Rock Road. The proposed pipeline route will primarily follow Aiken Road. The project team has identified this route as the most cost efficient reinforcement option for the medium pressure system. The detailed engineering, survey, right-of-way activities, and other preliminary work requested in this proposal will allow Gas Engineering to prepare detailed construction and easement drawings necessary for the project.

  As project efforts have progressed, the project team has identified the need to complete the Floyd's Fork horizontal directional drill (HDD) prior to the completion of detailed engineering and design efforts necessary to competitively bid the pipeline construction labor necessary to complete the project. The Floyd's Fork HDD is approximately 3,822 feet long, and requires a large temporary staging area immediately at the entrance to the new "Villas of Floyd's Fork" development. Currently, the site is under development, with grading, utility installation, and roadway work being completed. The property developer, Elite Homes, has expressed a concern that the temporary staging area will impact their ability to market and sell homes in the development, as well as delay greenspace work necessary to be completed as part of the development's Conservation Subdivision on file with the Louisville Metro Planning Commission.

  Because detailed engineering and design efforts have not yet produced an Issue for Bid set of plans, the project team has requested a lump sum price from ████████████████████████ to complete this work in February/March. ██████████████ was identified as the low bidder on the Paddy's Run Pipeline Project in 2016 and the Transmission Modernization Program in 2017. The project team intends to competitively bid the remainder of the project in the 1st Quarter of 2018 and to start construction on the remainder of the project late in the 2nd Quarter of 2018.

  The project team is requesting total project authorization for $8,176k to complete final engineering and design efforts, real estate and right-of-way acquisition, material purchasing,

and bid pipeline construction labor necessary to complete installation of the new pipeline. Although Detailed engineering and design work, along with right of way efforts that have been completed to date, have allowed Gas Engineering to further quantify the project estimate.

The following describes the project timeline:

- 2nd Qtr. 2017: Bid engineering design and survey work.
- 2nd Qtr. 2017: Engineering design, survey, and right of way activities begin.
- 4th Qtr. 2017: Purchase material to complete installation of 3,480 foot segment of pipeline to the "Villas of Floyd's Fork" and the 3,822' Floyd's Fork HDD
- 4th Qtr. 2017: Begin installation of 3,480 foot segment of pipeline to "the Villas of Floyd's Fork"
- 4th Qtr. 2017: Pipe and NDT inspection bid.
- 1st Qtr. 2018: Request full project approval from the Investment Committee.
- 1st Qtr. 2018: Complete installation of the Floyd's Fork HDD.
- 1st Qtr. 2018: Detailed engineering design completed.
- 1st Qtr. 2018: Pipeline construction labor bid.
- 1st Qtr. 2018: Pipeline material bid for the balance of project materials.
- 2nd Qtr. 2018: Right-of-way acquisition process completed.
- 2nd Qtr. 2018: Award project contracts.
- Late 2nd Qtr. 2018: Pre-construction meeting with successful contractors.
- Late 2nd Qtr. 2018: Begin pipeline construction.
- 4th Qtr. 2018: Complete pipeline construction.

- **Project Cost**
  The project team estimates expenditures of $8,176k to complete the engineering, design, right-of-way activities, bid pipeline labor construction, and complete regulator facility installation project. This includes purchasing all easements necessary and establishing temporary lease agreements to complete this project. The requested funding includes contingency of 10%, or $743k, primarily for the remaining sections of the project, which have not been bid yet.

Economic Analysis and Risks

- **Bid Summary**
  The engineering and survey work requested in this paper has been sent to firms that have recently been awarded EPCM contracts with LG&E to provide Not to Exceed estimates to complete the provided scope of work.

The engineering scope of work includes support to finalize the pipeline route, engineering and design work to develop pipeline construction bid documents along with post-bid engineering and design, as-built drawings and other support functions.

The surveying scope of work includes the work required to support the successful engineering and design firm's development of pipeline construction bids. This work was included in the scope of work for engineering and design.

Bids were requested from the following two (2) successful EPCM contract firms:

██████████████

████████████████████

The contract has been awarded to ███████████████ taking into consideration the firm's Not to Exceed estimate as well as the firm's availability to meet the project schedule. The total value of the EPCM contract, including Phase I survey activities, is ████████

- **Budget Comparison and Financial Summary**

Financial Detail by Year – Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,189	6,987	-	-	8,176
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,189	6,987	-	-	8,176
4. Capital Investment 2018 BP	2,020	5,148	-	-	7,168
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	2,020	5,148	-	-	7,168
7. Capital Investment variance to BP (4-1)	831	(1,839)	-	-	(1,008)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	831	(1,839)	-	-	(1,008)

Financial Detail by Year – O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The incremental funding needed in 2018 was approved through the Corporate RAC process in January. The net $1,008k increase compared to the 2018 BP is primarily due to higher estimated cost for HDDs based on current estimated pricing.

Financial Summary ($000s):

Discount Rate: 6.58%

Capital Breakdown:

Labor:	$ 148
Contract Labor:	$ 5,216
Right-of-way Acquisition:	$ 506
Permitting:	$ 10
Materials:	$ 686
Local Engineering:	$ 654
Burdens:	$ 213
Contingency:	$ 743
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 8,176

- **Assumptions** Arbough
  - Easement acquisition and right-of-way issues can be resolved prior to construction kick off in 2nd Qtr. 2018.
  - Costs for services included in the request are comparable to estimates provided by outside vendors.
  - Vendors complete project milestones according to project schedule.
  - Required permits can be obtained.

- **Environmental**
  - Applicable permits include KY Division of Water (KYDOW) Section 401 Water Quality Certification, KYDOW Permit for Hydro test Water Discharges, KYDOW Construction Storm Water, KYDOW Stream Crossing, KY Heritage Council, KY Dept. of Fish and Wildlife, USACE Nationwide Permit No 12 and Section 10.
  - There are no known environmental issues regarding air, lead and asbestos. The permits previously listed address requirements for water.
  - KPSC notification of construction.

- **Risks**
The primary risk of not completing this project by the desired date is the existing Crestwood/Simpsonville gas system will not be able to adequately support new residential development without potentially decreasing reliability to existing customers. Risks to the overall project costs are primarily based on the pipeline construction costs. These costs may vary depending on the pipeline construction company's availability and route characteristics such as number/length of HDDs and amount of rock that has to be removed during pipeline installation. Note that all alternatives considered have risks associated with their costs due to the issues listed.

This route will require many new easements as well. Any delays in easement acquisition could delay the commencement of construction activities.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the East End Reinforcement (Aiken Road HP Distribution Pipeline) project for $8,176k to improve the reliability of the system for current customers and support residential growth in the area.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: June 28, 2017

Project Name : East End Reinforcement (Aiken Road HP Distribution Pipeline)

Total Expenditures Current Request: $2,044k

Total Pending Project Estimate: $7,255k (Including $946k in contingency, balance to be requested in late 2017/early 2018)

Project Number(s): 152546

Business Unit/Line of Business: GDO/Gas Operations

Prepared/Presented By: Brian Lenhart/Tom Rieth

Executive Summary

The Crestwood/Simpsonville medium pressure gas distribution system currently operates at 45 psig and has a maximum allowable operating pressure (MAOP) of 50 psig (this system is currently being uprated to operate at 55 psig) and covers the mid-eastern portion of Jefferson County, including Anchorage, Crestwood, Eastwood, Simpsonville, and Pewee Valley, as well as portions of Oldham County and Shelby County. The system suffers from small diameter trunk lines, location barriers such as Floyd's Fork and Interstate 64, and consistent residential growth. The system has already experienced growth away from any strong sources of gas supply, and the existing infrastructure is no longer conducive to supporting new development. In order to serve its current and future loads, it has been determined that reinforcements are necessary. This project will improve reliability for existing customers as well as support future growth in the area by installing a new 8" steel high pressure distribution pipeline which will add a new supply of gas to the most constrained portion of the system.

The team is requesting $2,044k to complete survey, engineering, regulatory compliance strategy and design activities necessary to develop construction bid documents as well as to complete all real estate and right-of-way activities necessary for construction of the new pipeline. Once these activities have been completed, the team will return to the Investment Committee to request full funding for the project, including pipeline construction labor, later in 2017 or early 2018. Of the $2,044k, $452k is included for survey, engineering and design, real estate and right-of-way, material purchases, and pipeline construction costs necessary to complete installation of approximately 3,480' of the pipeline conjointly with the installation of the 6" medium pressure plastic pipeline extension necessary to serve the new "Meadows of Floyd's Fork" development.

The project was opened for $465k for the engineering contract only, but no actual costs were recorded through the end of April. The 2017 Business Plan included $500k in 2017 and $6,000k

in 2018, for a total of $6,500k. Additional funding for 2017 was approved in the June Anborough RAC process. 2018 funding will be addressed by request in the proposed 2018 Business Plan.

Background

The Crestwood/Simpsonville medium pressure gas distribution system covers the mid-eastern portion of Jefferson County, including Anchorage, Crestwood, Eastwood, Simpsonville, and Pewee Valley, as well as portions of Oldham County and Shelby County, is primarily fed from eight regulator facilities from both the Eastern Kentucky and Crestwood high pressure distribution pipelines. The area has been experiencing consistent residential growth away from any strong sources of gas supply, particularly in Norton Commons, Flat Rock Ridge, and Brookfield. The neighborhoods of Polo Fields and Persimmon Ridge represent the bulk of the existing constrained system, and currently have the lowest pressure points in the Crestwood/Simpsonville distribution system.

Gas Engineering has investigated several pipeline routes and tie in locations in order to determine the most efficient and cost effective solution for reinforcement to this system. Routes evaluated include:

1. Installation of 3.0 miles of 8" high pressure gas main from the existing Eastern Kentucky high pressure distribution pipeline along Aiken Road, starting at the intersection of Old Henry Road and Bush Farm Road and continuing to the intersection of Aiken Road and Flat Rock Road, where the pipeline will terminate at a new medium pressure regulator facility.

2. Installation of 3.2 miles of 4" high pressure gas main from the existing Crestwood high pressure distribution pipeline along Floydsburg Road, starting near the intersection of Abbott Lane and Myers Ave and continuing to the intersection of Floydsburg Road and Aiken Road, where it will terminate at a new medium pressure regulator facility.

   This reinforcement option requires the installation of 1.3 miles of 6" medium pressure pipeline along Johnson Road, starting at the intersection of Flat Rock Road and Aiken Road and ending at the intersection of Johnson Road and Aiken Road.

3. Installation of 3.2 miles of 4" high pressure gas main from the existing Crestwood high pressure distribution pipeline along Floydsburg Road, starting near the intersection of Abbott Lane and Myers Ave and continuing to the intersection of Floydsburg Road and Aiken Road, where it will terminate at a new medium pressure regulator facility.

   This reinforcement option requires the installation of two additional pipelines, the first of which includes 4.7 miles of 6" medium pressure pipeline along Long Run Road, starting at the intersection of Floydsburg Road and Aiken Road and ending at the intersection of Long Run Road and Shelbyville Road. The second pipeline includes extending the existing 8" high pressure distribution pipeline at Connor Station and Colt Run Road 2.8 miles to Long Run Road, where it will terminate at a new medium pressure regulator facility.

Following completion of this project, the gas system would have the available capacity to continue to reliably serve customers on the Crestwood/Simpsonville system and provide additional supply for future residential growth.

Alternatives Considered

- Recommendation: NPVRR: <u>$9,312k</u>

    Complete survey, engineering, and design activities necessary to develop construction bid documents as well as to complete all real estate and right-of-way activities necessary for construction of a new 3.0 mile 8" high pressure distribution pipeline along Aiken Road.

    This option provides the benefit of improving reliability of the existing Crestwood/Simpsonville medium pressure distribution as well as providing additional gas supply to serve future residential growth. The estimated capital cost is $7,255k.

- Alternative #1:   NPVRR: <u>$9,404k</u>

    Complete survey, engineering, and design activities necessary to develop construction bid documents as well as to complete all real estate and right-of-way activities necessary for construction of a new 3.2 mile 4" high pressure distribution pipeline along Floydsburg Road and a new 1.3 mile, 6" medium pressure distribution pipeline along Johnson Road.

    The route from the Crestwood high pressure distribution pipeline does not provide additional benefits to the recommendation and requires the installation of additional medium pressure distribution facilities. As such, this alternative is not recommended. The estimated capital cost is $7,374k.

- Alternative #2:   NPVRR: <u>$13,631k</u>

    Complete survey, engineering, and design activities necessary to develop construction bid documents as well as to complete all real estate and right-of-way activities necessary for construction of a new 3.2 mile 4" high pressure distribution pipeline along Floydsburg Road, as well as extending the existing 8" high pressure distribution pipeline at Connor Station and Colt Run Road 2.8 miles to Long Run Road and a new 4.7 mile, 6" medium pressure pipeline along Long Run Road.

    The route from the Crestwood high pressure distribution pipeline does not provide additional benefits to the recommendation and requires the installation of additional high pressure distribution and medium pressure distribution facilities. As such, this alternative is not recommended. The estimated capital cost is $10,696k.

Project Description

- **Project Scope and Timeline**
  The scope of this project includes installing approximately 3 miles of 8-inch, epoxy coated, steel pipeline with an MAOP of 200 psig from the Eastern Kentucky Pipeline near the intersection of Old Henry Road and Bush Farm Road to the intersection of Aiken Road and Flat Rock Road. A new regulation facility will be required at the termination of the new high pressure distribution pipeline to reduce the line pressure to the MAOP of the existing Crestwood/Simpsonville medium pressure distribution system. The proposed pipeline route will primarily follow Aiken Road. The project team has identified this route as the most cost efficient reinforcement option for the medium pressure system. The detailed engineering, survey, right-of-way activities, and other preliminary work requested in this proposal will allow Gas Engineering to finalize the route and prepare detailed construction and easement drawings necessary for the project.

  The project team is requesting authorization for $2,044k to perform engineering, design, and right-of-way work in order to competitively bid the pipeline construction labor required to complete this project. Further quantification of pipeline construction costs, along with right-of-way acquisition costs, will allow the project team to come back to the Investment Committee with final project costs including project contingency.

  The following describes the expected project timeline:

  - 2nd Qtr. 2017: Bid engineering design and survey work.
  - 2nd Qtr. 2017: Engineering design, survey, and right of way activities begin.
  - 3rd Qtr. 2017: Detailed engineering design completed.
  - 3rd Qtr. 2017: Purchase material and complete installation of 3,480' segment of pipeline to the "Meadows of Floyd's Fork."
  - 3rd Qtr. 2017: Pipeline construction labor bid.
  - 4th Qtr. 2017/early 2018: Request full project approval from the Investment Committee.
  - 4th Qtr. 2017: Pipeline material bid.
  - 4th Qtr. 2017: Pipe and NDT inspection bid.
  - 4th Qtr. 2017: Right-of-way acquisition process completed.
  - 4th Qtr. 2017: Award project contracts.
  - 1st Qtr. 2018: Pre-construction meeting with successful contractors.
  - 2nd Qtr. 2018: Begin pipeline construction.
  - 4th Qtr. 2018: Complete pipeline construction.

- **Project Cost**
  The project team estimates expenditures of $2,044k to complete the engineering, design, right-of-way activities, and other preliminary work required to develop a construction bid for this project. This work will include purchasing easements necessary to complete this project. The requested funding does not include any contingency for the engineering, design, surveying and right-of-way work associated with developing bid documents for the pipeline construction labor

along with right-of-way activity to acquire easements and complete permitting activity through project.

Economic Analysis and Risks

- **Bid Summary**

The engineering and survey work requested in this paper has been sent to firms that have recently been awarded EPCM contracts with LG&E to provide Not to Exceed estimates to complete the provided scope of work.

The engineering scope of work includes support to finalize the pipeline route, engineering and design work to develop pipeline construction bid documents along with post-bid engineering and design, as-built drawings and other support functions.

The surveying scope of work includes the work required to support the successful engineering and design firm's development of pipeline construction bids. This work was included in the scope of work for engineering and design. The survey scope of work does not include as built survey as the pipeline is installed, and will be awarded at a later time.

Bids were requested from the following two (2) successful EPCM contract firms:

- ▮▮▮▮▮▮
- ▮▮▮▮▮▮▮▮▮

The contract has been awarded to ▮▮▮▮▮▮▮▮▮, taking into consideration the firm's Not to Exceed estimate as well as the firm's availability to meet the project schedule. The total value of the EPCM contract, including Phase I survey activities, is ▮▮▮▮.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,044	5,211			7,255
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,044	5,211	-	-	7,255
4. Capital Investment 2017 BP	500	6,000			6,500
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	500	6,000	-	-	6,500
7. Capital Investment variance to BP (4-1)	(1,544)	789	-	-	(755)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,544)	789	-	-	(755)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The incremental funding needed in 2017 was approved through the Corporate RAC process through June. The 2018 BP will incorporate the revised amount for 2018.

The numbers in the table above, as well as the NPVRR figures in the document are based on the current estimate of the total project. The numbers in the financial summary below are for the preliminary engineering/design work and installation of the 3,400-feet of pipe in 2017 only.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 21
Contract Labor:	$ 829
Right-of-way Acquisition:	$ 750
Permitting:	$ 19
Materials:	$ 164
Local Engineering:	$ 214
Burdens:	$ 47
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$2,044

- **Assumptions**
  - Easement acquisition and right-of-way issues can be resolved prior to construction kick off in the spring of 2018.
  - Costs for services included in the request are comparable to estimates provided by outside vendors.
  - Vendors complete project milestones according to project schedule.
  - Required permits can be obtained.

- **Environmental**
  - Applicable permits include KY Division of Water (KYDOW) Section 401 Water Quality Certification, KYDOW Permit for Hydro test Water Discharges, KYDOW Construction Storm Water, KYDOW Stream Crossing, KY Heritage Council, KY Dept. of Fish and Wildlife, USACE Nationwide Permit No 12 and Section 10.
  - There are no known environmental issues regarding air, lead and asbestos. The permits previously listed address requirements for water.
  - KPSC notification of construction.

- **Risks**
  The primary risks of not completing the engineering, design, surveying and other preliminary work on schedule are not completing the project by the desired date and higher cost of construction due to a compressed schedule. The primary risk of not completing this project by the desired date is the existing Crestwood/Simpsonville gas system will not be able to adequately support new residential development without potentially decreasing reliability to existing customers. Risks to the overall project costs are primarily based on the pipeline construction costs. These costs may vary depending on the pipeline construction company's

availability and route characteristics such as number/length of horizontal directional drills (HDDs) and amount of rock that has to be removed during pipeline installation. Note that all alternatives considered have risks associated with their costs due to the issues listed.

This route will require many new easements as well. Any delays in easement acquisition could delay the commencement of construction activities.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the East End Reinforcement (Aiken Road HP Distribution Pipeline) project for $2,044k for survey, engineering, and design activities necessary to develop construction bid documents to competitively bid the construction labor for this project along with all real estate and right-of-way activities to acquire easements to ultimately construct a pipeline along Aiken Road that will improve the reliability of the system for current customers and support residential growth in the area. Full project approval will be sought later in 2017/early 2018.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: November 28, 2018

Project Name: Elevated Pressure Replacement Program - 2019

Total Expenditures: $3,490k   (Including $317k of contingency)

Project Number(s): 406000021

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Justin Hayes/Tom Rieth

Executive Summary

This proposal is intended to secure funding for the second year (2019) of a systematic program to reinforce areas of the Elevated Pressure (3.0 psig Max Allowable Operating Pressure (MAOP)) LG&E Gas Distribution System. The proposed funding for 2019 will support the installation of approximately 2.5 miles of new main, the uprate of approximately 1 mile of existing polyethylene main, the installation of approximately 100 new service lines, the uprate of approximately 200 existing polyethylene service lines, and the installation of one new regulator station.

Where reinforcement occurs, existing elevated pressure steel main pipelines will be replaced with polyethylene medium pressure (15 – 60.0 psig MAOP) pipelines. Likewise, existing steel service lines will be replaced with new polyethylene service lines. Existing elevated pressure polyethylene main lines and service lines will be uprated to operate at medium pressure. In some instances, existing polyethylene facilities may be replaced when the cost for replacement is less or when construction or customer considerations dictate the need for replacement.

The primary driver for the reinforcement work is to mitigate reliability risks in the elevated pressure system. These risks present in three major forms: hydraulic constraint in locations with substantial impact, uncertainty in total connected load due to unreported back-up generator installations, and the age of the system components and historical construction practices. The reinforcement work will have additional benefits including improving operational and emergency response flexibility. The majority of the current elevated pressure system is constructed of steel pipeline components, and valves are sparse in the existing system. These two characteristics result in the necessity for costly and time consuming shutdown techniques in the case of emergency or operational need. Furthermore, the relatively low operating pressure of the elevated pressure system greatly limits the ability to isolate small sections of the system. This could result in either higher customer and system impact or the necessity for a costly and time consuming by-pass installation when isolations are necessary.

The estimated cost for 2019 is $3,490k, which is included in the 2019 Business Plan (BP). Although there is an additional need for an estimated $5k in O&M funding which was not included in the 2019 BP and will be covered within GDO's 2019 forecast process.

Background

LG&E's Elevated Pressure Distribution System consists largely of three separate distribution systems within Louisville. These systems combined contain approximately 160 miles of main pipeline and 14,000 service lines. The customers consist mostly of residential, commercial, and light industrial groups. These three systems all have an operating pressure of 2.0 psig and an established MAOP of 3.0 psig. The Elevated Pressure is regulated and supplied to the distribution system by fifteen regulator facilities spread throughout the three systems.

Many parts of the elevated pressure system were designed and installed as far back as the 1950s. Over time customer load has increased and several areas of the elevated pressure system have exhibited declining operating pressures, especially during the heating season when demand is generally higher. On very cold days, it is possible for pressures in some isolated sections of the system to drop sufficiently to risk customer service outages.

In some portions of the elevated pressure system, the installation of emergency generators without information being provided to LG&E has created potentially significant undocumented transient demand on the elevated system. It is difficult to determine the effect this demand could have on the elevated pressure system if a large scale electrical disruption were to occur. If such a large scale electrical disruption were to occur it would activate all of the transient loading associated with the backup generators, which could cause the inability of the elevated pressure system to supply gas to all elevated pressure customers.

Finally, there are reliability concerns related to the age of the existing elevated pressure system. The oldest components of this system date from the early 1950s. Construction practices at the time do not conform to current standards and best practices. The elevated pressure system has a large number of mechanical couplings. Additionally, the older parts of the elevated pressure system have very few mainline or service valves. This limits our ability to quickly isolate a leak in an emergency situation, and requires more expensive and invasive isolation methods to be employed.

Therefore, the proposal outlined in this document is for the first project to mitigate reliability concerns of the elevated pressure system. The proposal is to follow the same general layout as the current elevated pressure system with only minor changes in layout as necessary. Pipeline sizes will be selected utilizing system level hydraulic modeling to account for current customer demand as well as system robustness and reliability. Existing steel main lines and service lines will be replaced with polyethylene pipe as they are encountered during the projects, while most existing polyethylene main lines and service lines will be uprated to their respective new medium pressure MAOP and operating pressure. This proposal only includes the scope for 2019, which provides reliability benefit and can be built upon by future projects on the elevated pressure system.

- **Alternatives Considered**
  1. Recommendation: NPVRR: $4,539k
  2. Do Nothing: NPVRR: N/A
     This is an option, but has considerable risk of service interruption and poor positioning for future load growth.

  3. Alternative #1: NPVRR: N/A
     Uprate the existing elevated pressure system to match surrounding medium pressure system pressures. Due to the lack of specific information on materials, installation, and design available on much of the existing elevated pressure system this is not feasible. In addition many of the components for which adequate records do exist are unsuitable for operation at the proposed higher operating pressures.

Compliance

The materials and construction activities will be done in a manner compliant with State and Federal Regulations, and Company procedures and construction standards. Materials not ordered on the current pipe, valve and fitting supplier contract will be specified to meet requirements in 49 CFR 192. Operator Qualification (OQ) tasks for the projects have been specified in contract documents for contractor construction work on the projects. Applicable company procedures have been communicated to (accessible by) the contractor. Recommended contractors will maintain an OQ plan approved by the Gas Safety and Technical Training department and will use the ███████████████████████ system to document on-going compliance.

Project Description

- **Project Scope and Timeline**

This project will consist of all activities and responsibilities necessary to achieve the following scope:

Scope Item Description	Quantity
Install new 2" Polyethylene Pipeline	2,400 Feet
Install new 4" Polyethylene Pipeline	4,400 Feet
Install new 6" Polyethylene Pipeline	4,100 Feet
Uprate Existing Polyethylene Pipeline	1,550 Feet
Install New Service (Customer and Company)	99 Services
Uprate Existing Polyethylene Service	186 Services
Install new Regulator Station	1 Regulator Station

In many ways this project will be very similar to both the Priority Main Replacement Program and the Large Scale Main Replacement Program. We have established company procedures and have built a repository of experience and knowledge in this type of work over the past 21 years. The modular nature of the proposed project plans will be a change from the structure of the other

two previous programs and is being introduced out of lessons learned from the previous Arbough projects to reduce the impacts of our work on the surrounding community.

All hydraulic analysis and material specification has been completed for this project. General pipe routes have been selected, and exact locations will be selected in the field based off in-situ conditions and existing utility locations. Preliminary right-of-way and easement research has started. Estimates of necessary man-hours and other logistics have been completed for completion of an estimate.

This project will start construction in January of 2019 and the first module is intended for completion by the end June 2019. At the completion of the first module, the second module (included in this IP scope) would immediately begin and be completed in December 2019. Both modules will follow as closely as possible the following timeline:
　　-Month 1-2: Install or uprate main lines
　　-Month 2-4: Finish installation of main lines and start and complete service lines
　　-Month 5-6: Complete restoration of all public and private assets

- **Project Cost**

  The cost of this project is $3,490k. This includes a contingency of 10% ($317k).

  Contingency is included to account for uncertainty in the estimation method used for this project's cost, specifically for uncertainty in the required man hours.

Economic Analysis and Risks

- **Bid Summary**

  Primary construction services were competitively bid when the program began in 2018 on a blended man hour rate structure. Two bidders provided proposals in response to the RFP and the work was awarded to the low bidder, ▮▮▮▮▮▮▮▮. A contract has been entered into with ▮▮▮▮▮▮ which expires in July 2021.

  All other materials and services will be supplied under existing contracts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	3,390				3,390
2. Cost of Removal Proposed	100				100
3. Total Capital and Removal Proposed (1+2)	3,490	-	-	-	3,490
4. Capital Investment 2019 BP	3,166				3,166
5. Cost of Removal 2019 BP	324				324
6. Total Capital and Removal 2019 BP (4+5)	3,490	-	-	-	3,490
7. Capital Investment variance to BP (4-1)	(224)	-	-	-	(224)
8. Cost of Removal variance to BP (5-2)	224	-	-	-	224
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	5				5
2. Project O&M 2019 BP	-				-
3. Total Project O&M variance to BP (2-1)	(5)	-	-	-	(5)

Proposed capital spending is included in the 2019 BP. O&M spending of $5k will be covered within GDO's 2019 forecasting process.

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 202
Contract Labor:	$2,051
Materials:	$ 512
Local Engineering:	$ 169
Burdens:	$ 186
Contingency:	$ 317
Miscellaneous	$ 53
Reimbursements:	($ 0)
Net Capital Expenditure:	$3,490

- **Assumptions**

  - Construction resources will be available to start construction of this project in January in sufficient numbers to complete this project on the proposed schedule.
  - No State or City permitting issues will prevent the start of construction.
  - Costs will equal the average costs of the Large Scale Main Replacement program from 2013-2017. These years were used because they represent a similar scope.
  - The project will be able to complete all work in the sequence planned.

- Winter weather will not prevent completion of all service work.   **Arbough**
- Weather will allow completion of all work without significant delay.
- Winter temperatures will be high enough to allow completion of all final paving.

- **Environmental**

There are no known environmental issues regarding air, lead or asbestos. Applicable permits will be obtained as needed.

- **Risks**

  - Poor weather could delay the completion of this project. As a result financial obligation for restoration would continue into 2020 and the social impact of the project would be extended.
  - The contractor may not have the resources available to start this project on our proposed schedule. This could slow or delay the construction and push additional work and cost into 2020.
  - Cold winter weather may discourage customers from scheduling their service change over. This will reduce the project efficiency, drive up costs, and possibly delay work and costs into 2020.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the 2019 Elevated Pressure Replacement Project for $3,490k to increase system reliability and eliminate existing system risks.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	
Chief Financial Officer		

Paul W. Thompson	Date
Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: September 26, 2018

Project Name: Enterprise GIS

Estimated Enterprise GIS Total Expenditures: $39,404k (2017-2023)

Total Expenditures Requested at This Time: $11,468k (Including $1,300k of contingency [15% of remaining Phase 1 spend] and the 2017 License Purchase of $1,486k)

Project Number(s): IT0101B, IT0569B, IT0927B

Business Unit/Line of Business: Information Technology (IT), IT Telecommunications (Telecom), Generation Services, Electric Transmission, Gas Distribution Operations (GDO), Electric Distribution Operations (EDO)

Prepared/Presented By: Denise Simon/ Chris Talley/ Alpha Troutman

Executive Summary

A Geographic Information System (GIS) is used by multiple lines of business at LKE to manage assets and map asset locations. The existing GIS Smallworld application will not support all of the upcoming gas regulatory requirements and the Black and Veatch (B&V) GIS data model has reached the product end-of-life. In 2017 LKE evaluated the company-wide GIS needs and made the decision to implement a single GIS platform. ▮▮▮▮ was selected as the vendor, enterprise licenses were purchased in the amount of $1,486k and the direction was set to implement in a phased approach. A System Integrator (SI) will be leveraged to assist with the overall implementation of the project. This Investment Proposal describes the Phase I Enterprise GIS project details and costs along with a summary of the subsequent phases. The initial phase includes the GIS design, build and implementation for Electric Transmission, Telecom and Generation Services, the GIS design for GDO, as well as the architecture design for all future phases. Phase I benefits include enhanced asset management and better decision making through information sharing. The total project cost is estimated at $39,404k including the $1,486k spent on licenses in 2017.

Through this Investment Proposal, the impacted lines of business and IT seek agreement with the overall Enterprise GIS Project as well as capital funding authority of $11,468k from the Investment Committee to enable execution of Phase I of the project. The 2018BP includes $10,800k for capital investment in 2018-2022. The proposed 2019BP includes $36,697k for capital investment in 2019-2023 including $1,486k in 2017, $1,221k in 2018, $7,297k in 2019 and $1,464k in 2020 for Phase I. Investment Proposals will be submitted for Phases II and III as business requirements and estimates are refined.

Background

Enterprise GIS Project Phases

A phased approach to implementing the Enterprise GIS is being utilized as shown below.

Capital Expenditure – Total: $39.4M
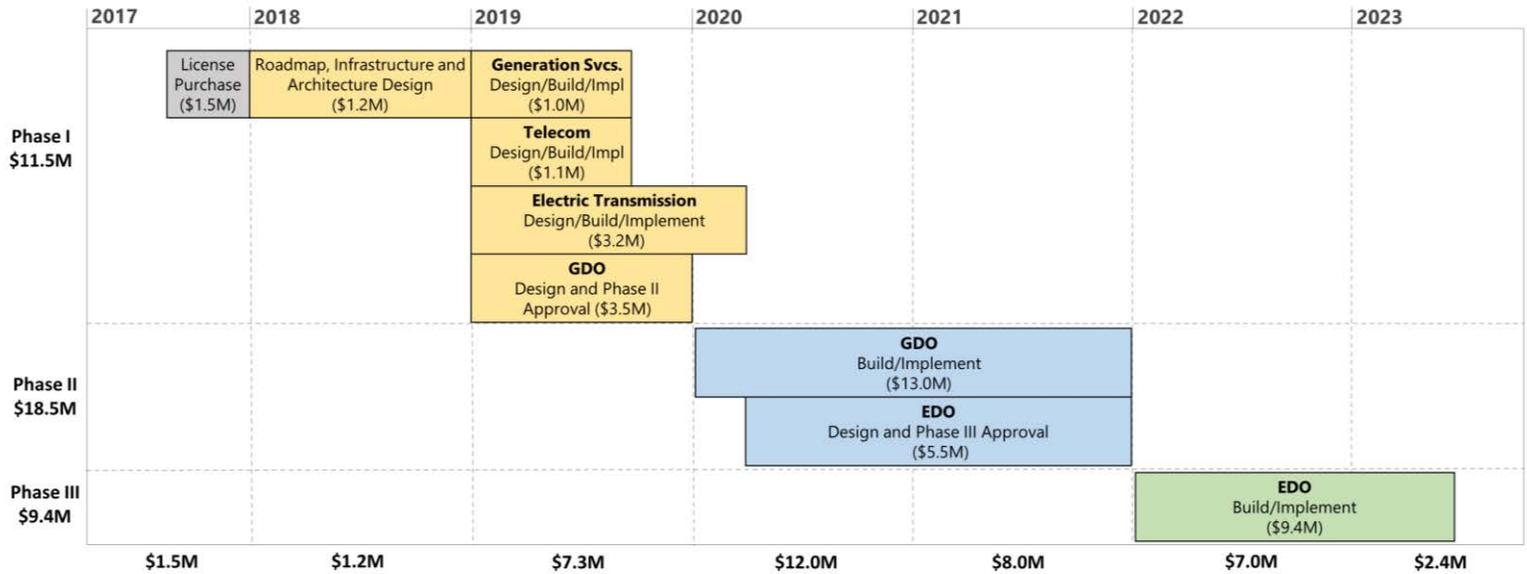
Phase I includes the following:

- Development of GIS Roadmap and infrastructure for GDO, EDO, Electric Transmission, Generation, and Telecom.
- Electric Transmission: Implementation of the on-premise ▮▮▮ GIS solution to enable future integrated mapping of confidential data such as substation and outage information with cloud hosted inspection data. Enhancements outside of this project present the opportunity for improved customer restoration decision making.
- Telecom: Implementation of the ▮▮▮ GIS system to replace the paper and Google Earth-based solution used today to allow assets to be geospatially located and managed more effectively.
- Generation Services: Replacement of the PC-based standalone GIS with the enterprise solution to allow better sharing of geotechnical and impoundment inspection data.
- GDO: Development, design and implementation of plan to replace the GDO Smallworld GIS with the Esri solution. This will allow the GIS to more comprehensively support upcoming gas regulatory requirements.

Phase II and III will include the following:
- Phase II: GDO implementation; EDO design and planning for Phase III (Est. $18.5M in 2020 – 2021)

Phase III: EDO implementation (Est $9.4M in 2022 – 2023)

History

LKE has implemented multiple GIS solutions with the original implementation of the Smallworld GIS in the 1990s. Electric Transmission and Generation Services deployed separate Esri solutions in 2015. Below is a timeline of major events:

Year	Event
1996	KU original implementation of Smallworld
1998	LG&E original implementation of Smallworld
2000-2004	Merged LG&E and KU into a single implementation of Smallworld with the B&V Energy Network Object Model (ENOM) data model
2015	Last upgrade of the Smallworld software
2015	Electric Transmission implementation of a hosted interim ▮ solution
2015	Generation Services implementation of PC-based ▮ solution

Drivers

The decision to move to an Enterprise ▮ GIS platform was driven by the following:

Functionality
The current solution for EDO and GDO is GE's Smallworld utilizing the ENOM data model. All new functionality with the upgraded versions of Smallworld are based on GE's new data model. Therefore, with its existing ENOM data model, LKE cannot leverage any of the new GE solutions. In addition, LKE's current Smallworld environment lacks all of the functionality needed to meet anticipated gas regulatory requirements which will necessitate more in-depth asset records and significant customizations.

The current solution for Electric Transmission was implemented as an interim solution until an enterprise GIS is established. The interim transmission GIS functionality is limited due to being a cloud-based solution. The benefits of interfacing with internal systems such as Cascade, Transmission Outage App (TOA), and Transmission Reliability Outage Data System (TRODS) are not achievable due to security concerns.

Telecom does not currently have a GIS solution and presently stores data in various formats including Google Earth, Microsoft Visio, and paper.

Support   **Arbough**

B&V is no longer investing in the ENOM data model, and LKE is the last B&V customer still using ENOM. As shown below, the data model is an integral part of the GIS solution.
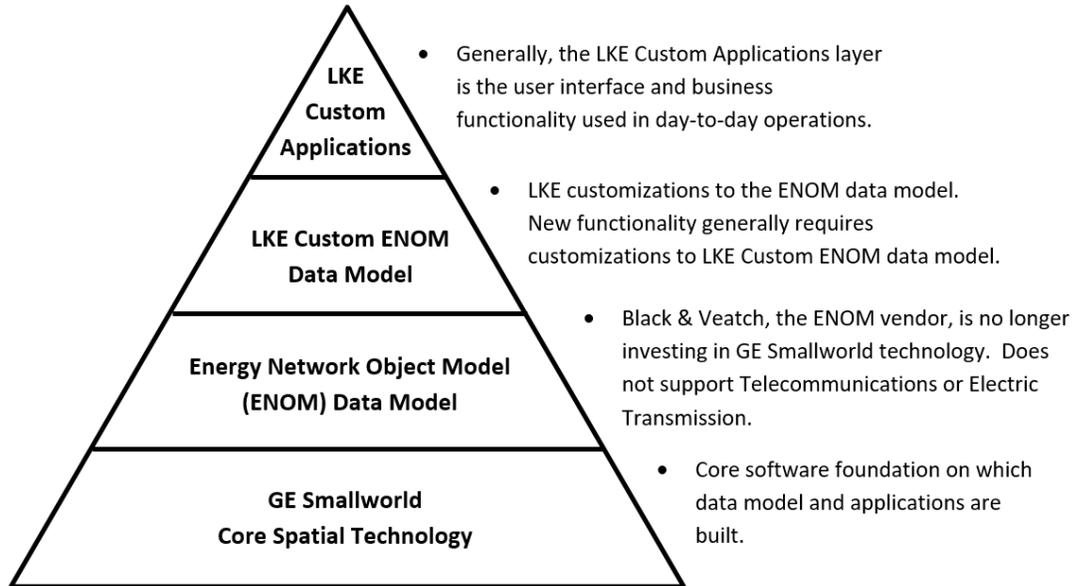
B&V no longer maintains resources on staff to support this model and relies on a third party to provide assistance.

LKE continues to pay maintenance to Smallworld to provide software support, patches and upgrades. Smallworld is developed with a toolkit called Magik which is proprietary and has few resources available within the consulting market.

Continued use of the current Smallworld GIS version could result in any or all of the following issues in coming years.

- Security patching
- Server upgrades
- Java upgrades
- Citrix upgrades
- Oracle database upgrades

Benefits of an enterprise GIS platform
An enterprise ▮▮ solution offers the on-going support and functionality required by GDO and EDO as well as providing broad access to integrated geospatial data and applications throughout the organization. Geospatial information can be integrated with other enterprise applications to geo-enable executive analysis and decision-support systems.

An on-premise GIS platform of Electric Transmission Lines asset data will allow   **Arbough** combination of data from Electric Transmission's externally hosted field inspection system with the Electric Transmission data warehouse. Field inspection data including photos could be layered visually in maps with sensitive data such as Cascade substation device work orders and recent test data, TOA outage data, lightning strike data and historical fault locations. This layered map view of the data from multiple systems could improve restoration decisions and times by providing additional near real-time assessment data of the Transmission grid. Moving to a standard Esri data model will also facilitate integration with other Electric Transmission tools such as TOA, TRODS and Cascade as shown below.
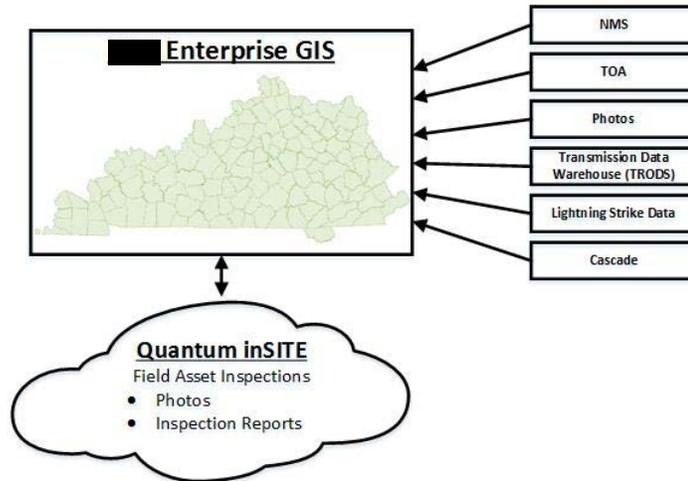
Additionally, the on-premise GIS platform will allow Transmission to leverage Esri dashboarding tools on a real-time version of our geo-spatial data. Presently this requires a two step process to create a static copy of the data set and then move it into an ArcGIS online environment. This manual process will be eliminated with the Enterprise GIS solution and allow the dashboard tools to interact with a live version of the data set.

Telecom currently uses Google Earth to map Company-owned and Partner-owned outside plant fiber cable routes. Associated documentation including fiber splice detail drawings, fiber performance test results, and 3rd Party Agreements are stored in a local database in a variety of formats including VISIO drawings, Excel files, and PDF files. Information such as electric line routes, pole ownership, pole numbers and buried gas line routes are not available with Telecom's current Google Earth solution. Also, mapping tools used by the lines of business do not identify Telecom's outside plant fiber cable. The current scenario creates engineering and design challenges for new fiber cable routes in proposed gas, electric distribution and transmission route construction and renovation projects. Also, during storm restoration efforts, identifying damaged fiber and repairing fiber is often more difficult with multiple mapping systems being utilized across the lines of business. The ▇ GIS platform will enable Telecom to more accurately identify fiber cable damage locations utilizing pole and structure numbers, and be able to provide a faster response.

An enterprise platform would allow all lines of business to readily see assets across the company layered together providing a much clearer view of potential interactions in the

various facilities for routine operations and maintenance work and, more critically, during **Although** emergency storm restoration efforts.

Alternatives Considered

Recommendation: NPVRR: ($000) $43,688
Design and implement ▮▮ Enterprise GIS with SSP Innovations as the system integrator.

The recommendation is to move forward with the design and implementation of the ▮▮ Enterprise GIS in a 3-phased approach utilizing the expertise of SSP Innovations as the SI. This recommendation meets the business requirements for an enterprise GIS. The complete Enterprise GIS project (2017-2023) was modeled in the Capital Evaluation Model (CEM).

Alternative #1:   NPVRR: ($000) $54,281
Upgrade and continue with GE Smallworld.

This alternative is unacceptable due to gaps in requirements and long term dependency on the vendor for all enhancements. Significant customization would be required along with the conversion from B&V ENOM data model to Smallworld v5 and the GE data model. In addition to Smallworld, an in-house ▮▮ platform will need to be implemented and maintained for Generation and Electric Transmission as well as additional ▮▮ interfaces to support GDO. Long term maintenance would be necessary to bridge the Smallworld and Esri platforms in order to simulate an Enterprise GIS. The complete Enterprise GIS project using ▮▮ and Smallworld was modeled in the CEM. The team does not recommend this option.

Alternative #2:   NPVRR: N/A
Do Nothing:
This alternative puts LKE at risk due to lack of Smallworld functionality required to meet upcoming gas regulations and the need to move off a data model that is currently at end of life. This option has not been modeled in the CEM due to the lack of long-term feasibility. The team does not recommend this option.

Project Description

- **Project Scope and Timeline**
  The Enterprise GIS will be implemented in a phased approach as shown below.

LOB	Roadmap, Infrastructure, and Architecture	Design	Build	Implementation
IT Telecommunications	Phase I	Phase I	Phase I	Phase I
Generation Services	Phase I	Phase I	Phase I	Phase I
Electric Transmission	Phase I	Phase I	Phase I	Phase I
Gas Distribution Operations	Phase I	Phase I	Phase II	Phase II
Electric Distribution Operations	Phase I	Phase II	Phase III	Phase III

The following is the Phase I project scope:
- Develop a roadmap, infrastructure and architecture scalable to meet future phases.
- Design, build and implement the ▮ Enterprise solution for Electric Transmission, Telecom and Generation Services.
- Develop the design for the GDO ▮ Enterprise solution.

Tentative key milestones for the complete Enterprise GIS project are as follows:

Milestone Event	Date
Develop Roadmap, Governance and Organization Change Management Plan	Q4 2018
Develop Architecture and Infrastructure Design	Q4 2018
Begin Design for Generation Services, Telecom, Electric Transmission and GDO	Q1 2019
Generation Services go live	Q2 2019
Telecom go live	Q3 2019
GDO Design complete	Q4 2019
Phase 2 Planning	Q4 2019
Electric Transmission go live	Q1 2020
GDO go live	Q4 2021
EDO Design complete	Q4 2021
Phase 3 planning	Q4 2021
EDO go live	Q4 2023

- **Project Cost for the Enterprise GIS Project by Phase.**

Capital cost ($000)	2017	2018	2019	2020	2021	2022	2023	Total
Phase I	$1,486	$1,221	$7,297	$ 1,464				$11,468
Phase II				$10,536	$8,000			$18,536
Phase III						$7,000	$2,400	$ 9,400
Total	$1,486	$1,221	$7,297	$12,000	$8,000	$7,000	$2,400	$39,404

O&M cost ($000)	2017	2018	2019	2020	2021	2022	2023	Total
Phase I		$ 260	$ 632	$ 301	$ 301	$ 301	$ 307	$ 2,102
Phase II				$ 2,350	$2,400			$ 4,750
Phase III						$2,350	$2,350	$ 4,700
Total	$ -	$ 260	$ 632	$ 2,651	$2,701	$2,651	$2,657	$11,552

Economic Analysis and Risks

Bid Summary

A Request For Proposal (RFP) was sent to four prospective bidders and following a thorough RFP process, two potential SIs were evaluated. This included presentations by each vendor, reference calls and two separate three day planning sessions to create a budget and project plan.

Bidder #1: SSP Innovations

SSP Innovations was the unanimous recommendation for the role of SI from a team including IT and representatives from each of the impacted lines of business. The decision was based on scoring criteria including favorable cost.

Bidder #2: UDC Inc.

It was decided by the core IT and business team that UDC Inc, in addition to providing a higher cost, was not the preferred SI for the project. The customer references and the proposed work plan were not optimal for this project.

RFP Vendor Scoresheet	SSP Innovations	UDC Inc.
MBE/WBE	No	No
ACA Compliance	Yes	Yes
Total Vendor Cost ($000s)	$2,904	$3,773
Total Price Score	30	23
Completeness of Proposal	10	10
Proposed Work Plan	25	25
Key Resources	15	15
References	10	0
Company Leadership	10	10
Scoresheet Criteria Total	**100**	**83**

- **Budget Comparison and Financial Summary for the complete Enterprise GIS Project**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,486	1,221	7,297	29,400	39,404
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,486	1,221	7,297	29,400	39,404
4. Capital Investment 2018 BP	1,486	3,000	2,000	5,800	12,286
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,486	3,000	2,000	5,800	12,286
7. Capital Investment variance to BP (4-1)	-	1,779	(5,297)	(23,600)	(27,118)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	1,779	(5,297)	(23,600)	(27,118)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	260	632	10,660	11,552
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	(260)	(632)	(10,660)	(11,552)

The 2018BP was not adjusted since fully developed estimates had not been completed at the time. The 2019BP (Capital and O&M) funding includes fully developed estimates for Phase I and revised estimates for Phase II and Phase III. However, final detailed estimates for Phase II and III will be developed as business requirements are refined.

Financial Capital Summary for Phase I ($000s):	
Discount Rate:	6.59%
Capital Breakdown:	
Internal Labor:	$3,872
Contract Labor:	$3,620
License Purchase (2017)	$1,486
Other (taxes, travel, office supplies etc)	$1,190
Contingency (15% excluding licenses):	$1,300
Total Capital Expenditure:	$11,468

The capital breakdown above is for the 2017-2020 Phase I of the Enterprise GIS Project to be consistent with the capital investment approval sought in this proposal. The NPVRR calculations in the document reflect the complete Enterprise GIS Project.

Assumptions

- Phase II and Phase III of the Enterprise GIS project will be brought to the Investment Committee for approval prior to commencement of work.
- SSP Innovations is successful with Phase I implementation and earns Phase II project work.

Risks   **Arbough**

- SSP Innovations fails to earn Phase II project work resulting in renewal of vendor selection and delay of the project for GDO and EDO.
- During Phase I the System Integrator will conduct a conflation analysis to determine the degree of spatial location variation between the assets from different lines of business. If conflation work is recommended, incremental O&M funds will be required.
- Constraints on internal resources due to multiple competing projects.
- Maintaining consistent resources from the System Integrator given the length of the project.
- Technical complexity of the GIS project.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve Phase I of the Enterprise GIS Project for $11,468k to complete the GIS design, build and implementation for Electric Transmission, Telecom and Generation Services, the GIS design for GDO, as well as the architecture design for all future phases.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:	DocuSigned by:
kent Blake	*kent Blake* DOA for Paul Thompson
C055E669F1EB443...	C055E669F1EB443...

Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: 7/26/2017

Project Name: GH Barge Unloader Recert

Total Expenditures: $9,089k (Including $826k or 10% contingency)

Project Number(s): 140203

Business Unit/Line of Business: Generation

Prepared/Presented By: Steven Straight/Steven Turner

Executive Summary

This project is for the recertification of the Ghent Continuous Barge Unloader (CBU). The scope of this project includes the engineering, fabrication, procurement and construction required to replace several major structural components of the CBU, fabrication and installation of a new operator's cab and replacement-in-kind of various CBU components.

The Ghent CBU has been in service since 1973 and has begun to exhibit signs of degradation and component failures in the past several years. The CBU unloads approximately six million tons of coal per year to maintain unit operations and the station's stockpile. The CBU is the station's only means of unloading coal.

A total of $3,720k was included in the 2017BP. That amount was based on cost estimates derived in 2013. Additional inspections were performed in 2016, and an updated scope of work was developed. The project was bid as a turnkey project including the engineering, fabrication, procurement, management and construction required to complete the work. An increase in the scope drove the cost to the current proposed amount of $9,089k (See Appendix I). The 2018 proposed amounts will be requested as part of the 2018 business planning process to be completed later this year.

Background

The Ghent Station Heyl & Patterson designed CBU was constructed in the early 1970's and began operation in 1973 when the station's first generating unit began operation. Since 1973 the CBU has operated nearly continuously until the past several years when several major components have either failed or begun to exhibit signs of degradation. In the early 1990's the CBU was upgraded to accommodate the unloading of limestone in addition to coal. In 2005, structural repairs were made to address several cracks in structural members. The CBU is inspected annually and areas of concern have been noted which need to be corrected to ensure the reliable and safe operation of the CBU for the next thirty years.

All coal used to operate the Ghent Station must be unloaded from barges on the river via the CBU.

- **Alternatives Considered**

  1. Recommendation: NPVRR: ($000s) <u>$10,568</u>

  2. Alternative #1: Do Nothing   NPVRR: ($000s) <u>$26,764</u>
     [This alternative should not be chosen because the CBU has been exhibiting signs of damage for several years and poses a risk to operations and the CBU operators.]

  3. Alternative #2: Total Replacement   NPVRR: ($000s) <u>$33,092</u>
     [This alternative should not be chosen due to replacement project costs being much greater than the recommendation. Also, this alternative would delay the project several years allowing the CBU to further degrade and continue to pose a risk to operations and the CBU operators.]

Project Description

- **Project Scope and Timeline**

  The scope of this project includes the engineering, procurement and construction required to repair and replace several major structural components of the CBU, fabrication and installation of a new operator's cab and replacement-in-kind of various equipment. A scope was first developed for this project in 2013 based on annual inspections of the CBU. In 2016, an inspection focused on extending the life of the CBU was completed, and based upon this inspection the scope was revised and expanded. A list of scope items added and which were increased in 2017 can be found attached in Appendix I.

  Milestones:
  - July 2017 – Investment Committee meeting and approval
  - August 2017 – Issue purchase order
  - August 2017 – Project kick-off, begin engineering, fabrication & procurement
  - October 2017 –2017 Outage work
  - December 2017 – Finish fabrication
  - September 2018 – Begin 2018 Outage work
  - October 2018 – Complete 2018 Outage work
  - November 2018 – Complete Punchlist items

- **Project Cost**

  This project is expected to cost a total of $9,089k. The material cost is estimated to be $3,265k and the labor is estimated at $4,405k. Burdens are estimated to be $593k. Contingency (10%) is $826k and will cover any unknown conditions discovered once the work begins that would be directly related to the scope of the Project. The labor will be

awarded as lump-sum and any additional work discovered during the Project will be**Arbough** completed on a T&M basis.

Economic Analysis and Risks

- **Bid Summary**

  The project was bid as a turnkey project including the engineering, fabrication, procurement, management and construction required to complete the work. The bidders include the ████ ████████████████████████, general contractors and bulk material handling engineering and equipment companies. Proposals were received from ████████████████, ████████ ████████ and █████. The contract is still being negotiated. The table below shows the provided pricing and normalized comparison.

Engineering & Material (2017)			
Engineering Services			
Material/Equipment			
Other			
TOTAL 2017			
Installation (2018)			
Mobilization/Demobilization			
Demolition/Removal Labor			
Installation Labor			
Material/Equipment			
Other			
TOTAL 2018			
TOTAL BID			
Normalized Comparison*			

*The normalized comparison is attached as Appendix II.

Thorough review of the short list proposals from ████████████ and ████████ ████████ has generated concerns with regard to the level of confidence in the lower priced ████████ offering. While ████████████ has taken an all-encompassing approach, a close review of ████████'s proposal revealed several gaps with the potential for significant delays, large change orders or both. Multiple large cost items are included in the ████ ████████ proposal which ████████ did not include, for example the cost of a full-time tug boat during the five week outage and adequate quality controls during the fabrication of the CBU structural components. ████████████████ also proposed to execute some scope items in an unsatisfactory manner. For these reasons, award to ████████████ is being recommended. Benefits for this selection are shown as normalized adders/deducts in the attached Appendix II.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	3,756	4,752	-	-	8,508
2. Cost of Removal Proposed	-	581	-	-	581
3. Total Capital and Removal Proposed (1+2)	3,756	5,333	-	-	9,089
4. Capital Investment 2017 BP	3,720	-	-	-	3,720
5. Cost of Removal 2017 BP		-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	3,720	-	-	-	3,720
7. Capital Investment variance to BP (4-1)	(36)	(4,752)	-	-	(4,788)
8. Cost of Removal variance to BP (5-2)	-	(581)	-	-	(581)
9. Total Capital and Removal variance to BP (6-3)	(36)	(5,333)	-	-	(5,369)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 4,405
Materials:	$ 3,265
Local Engineering:	$ 130
Burdens:	$ 463
Contingency:	$ 826
Reimbursements:	($0)
Net Capital Expenditure:	$ 9,089

- **Assumptions**
  The Capital Evaluation Model contains the following assumptions:
  o An availability disimprovement of forty-eight weeks is assumed for both alternatives. This is based on a twelve week fabrication and five week installation schedule minus the station's five week coal supply then multiplied by the four units at the station.
  o Unbudgeted O&M Costs assumed for both alternatives are based on miscellaneous repairs related to the CBU.
  o Alternative #2 assumes a completely new CBU and associated conveyors and structures would cost $30,000k.
  o The potential increase in steel prices was not incorporated into either alternative.

- **Environmental**

The Army Corps of Engineers will be notified of the work on the river as required.

	New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.	
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes; See Background section
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**
If this project is not completed during the 2018 Coal Yard fall outage, continued corrosion and degradation of the Barge Unloader structure will occur which will increase the potential of having a structural failure which would affect the station's ability to supply the operating units with fuel.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the GH Barge Unloader
Recertification project for $9,089k to ensure the station can continue to safely and reliably
unload coal.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the
members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the
signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Appendix I

- 2017 scope items not included in 2013 scope

    o New LED lighting of structure(s) *(+ at least $75k)*

    o Replace counterweight pins *(+ at least $25k)*

    o Prep and re-grout cantilever hoist drive base *(+ at least $75k)*

    o Replace operator's cab support structure *(+ at least $50k)*

    o Replace 1A Conveyor and conveyor structure *(+at least $500k)*

    o Replace the bucket wheel hood *(+ at least $70k)*

    o Replace the boom, bucket slide assembly and related supports *(+ at least $350k)*

    o Replace the bucket discharge chute *(+ at least $50k)*

    o New positioner arm and wheel *(+ at least $100k)*

    o New hydraulic power unit, cylinder and related piping *(+ at least $100k)*

    o New brakes and coat east and west barge hauls *(+ at least $50k)*

- 2017 scope items with increased scope from 2013

    o Sheave and cable replacement; $50k included for 2013 and low bid of $375k for 2017 scope

    o Service crane replacement; $100k included in 2013 and bids of $250k for 2017 scope

    o Counterweight drums, shafts, bearings and associated cables and connections; $50k estimate in 2013 and low bid of $531k for 2017 scope

    o New cantilever hoist motor, brakes, drum, gear reducer and VFD; $125k estimate in 2013 and bids of $460k for 2017 scope

    o Cantilever hoist cables and sheaves; $25k estimate in 2013 and bids of $225k for 2017 scope

    o Cantilever box girder replacement scope significantly increased to include the entire cantilever assembly rather than only replacing sections of the box girder due to safety and installation concerns; approximately $425k increase in cost from 2013 scope to 2017 scope

Appendix II
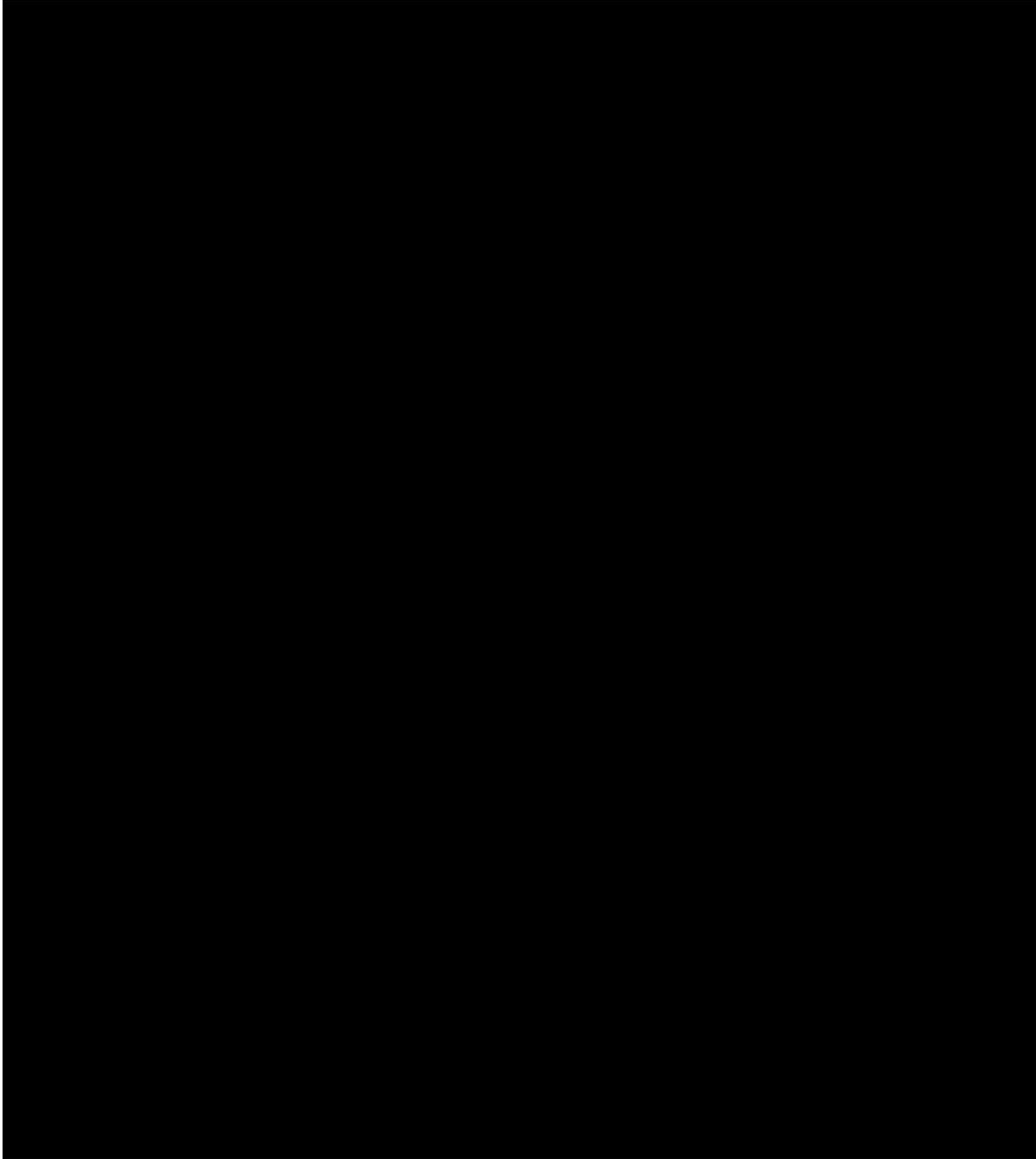
Investment Proposal for Investment Committee Meeting on: May 30, 2017

Project Name: GH1 SCR Catalyst L3 New

Total Expenditures: $2,493k (including $227k (10%) contingency)

Project Number(s): 144326

Business Unit/Line of Business: Power Generation/ Ghent 1

Prepared/Presented By: Dara Griggs

Executive Summary

The scope of this project includes the purchase and installation of new plate type catalyst for the GH1 Selective Catalytic Reduction (SCR) layer 3. The removed layer 3 catalyst will be mechanically cleaned and recycled. If the catalyst is not installed, the SCR performance will degrade below the target 90% removal rate and additional NO_x allowances will be surrendered by KU. As the SCR catalyst deactivates, the higher ammonia slip through the SCR will increase the risk of an unplanned outage due to air heater pluggage.

The total GH1 project cost is $2,493k. The project materials including the catalyst material and installation labor have been competitively bid in a fleetwide bid process. The catalyst will be ordered in Q3 of 2017. Bolt-on style doors will be added to this SCR layer based on positive results with this feature on Layer 1. Cleaning labor will be bid by the plant in January 2018. The current 2017BP includes approximately $832k for 2017 and $1,661k for 2018. It is recommended that the project be approved in order to meet the target NO_x emissions.

Background

The GH1 SCR was placed in service in March 2004 and is designed to hold three catalyst layers. The two top layers were loaded initially, and the third bottom-most layer of catalyst was loaded in 2006. During the February 2011 outage the top layer (layer 1) was replaced with new catalyst. The new layer 1 was low SO_2 to SO_3 conversion type catalyst. Consequently, the SCR had a shorter active life and a catalyst change out was required in 2012. In February 2012, the layer 1 (low SO_2 conversion) catalyst was moved to layer 3 and the regenerated original catalyst from layer 1 was reinstalled in layer 1. In 2014, catalyst activity declined and a new catalyst, Hitachi CM, was installed in layer 2. In 2016, the activity levels in layer 1 and layer 3 required that they be replaced with a regenerated Trimble County layer and the regenerated original catalyst from layer 3, respectively. Due to the decline of the regenerated catalyst activity in layer 3, a new catalyst layer is required in 2018 to meet the requirements of the Cross-State Air Pollution Rule (CSAPR) that have lowered ozone season limits beginning in May 2017.

- **Alternatives Considered**
    1. Recommendation: Replace GH1 SCR L3 with new catalyst
       NPVRR ($000s): $3,179
    2. Alternative #1: Delay Project Until 2019   \
       NPVRR ($000s):$3,898
    3. Alternative #2: Do Nothing
       NPVRR ($000s): $6,436

The alternatives to this project are to *delay the project until 2019* or to *do nothing.* The *do nothing* alternative can be eliminated based upon the NPVRR and increased NO_x emissions that would occur. Delaying the project until 2019 is undesireable as well due to the potential for increased ammonia slip leading to an increase in forced unit outages to wash air heaters. Additionally, KU will have to surrender additional NO_x emissions allowances during ozone seasons to meet recent CSAPR regulations.

Project Description

- **Project Scope and Timeline**
  The scope of this project includes the purchase and installation of new plate type catalyst for the GH1 SCR layer 3. The new catalyst will be installed in layer 3 and the old layer 3 catalyst will be mechanically cleaned and recycled.

>   February 2017- Bid for Removal/Installation Labor
>   March 2017- Bid for New Catalyst Layer
>   May 2017 – Investment Committee meeting and approval
>   July 2017 – Issue purchase order for catalyst
>   November 2017- Issue purchase order for bolt-on style doors
>   January 2018- Bid for Catalyst Cleaning
>   January 2018- Issue purchase order for seals
>   April 1, 2018 – Catalyst delivery to Ghent
>   April 15, 2018 – Install new catalyst in layer 3
>   May 2018- Tune U1 SCR
>   May 2018- Mechanically clean and recycle used layer 3

- **Project Cost**
  The total project cost, material and labor, is $2,493k with $832k in 2017 and $1,661k in 2018. A total contingency of $227k (10%) is included in the project cost. The contingency level is based on past catalyst projects at the plant. The project material costs include catalyst, seals, bolt-on style doors, and miscellaneous materials for installation that are subject to change as material costs change.

  The cost estimate for catalyst material is based on bids received in March 2017 from a fleetwide RFQ. Installation costs have been bid in a fleetwide contract and have been awarded to ███.

Tuning labor costs have been bid in a fleetwide contract and have been awarded t▮▮▮▮▮▮ Cleaning labor and other labor will be awarded in 2018.

Economic Analysis and Risks

- **Bid Summary**
  An RFQ has be issued by Commercial Management to qualified catalyst suppliers. A detailed bid evaluation has been completed and the scores can be seen below. ▮▮▮▮▮▮▮▮▮▮ ▮▮▮▮▮▮▮▮▮▮▮ was the recommended bidder.

Ghent 1 Layer 2	Possible Score	▮▮	▮▮	▮	▮	▮▮	▮▮
Normalized Pricing (new and end of life) and remedies offered	60	52.7	40.6	49.6	47.5	48.7	38.4
Technical Evaluation (Exceptions, SO2 conversion, Potential Guarantees – new/ end of life)	40	44.7	44.7	39.8	39.8	41.5	43.5
Total Evaluated Score	100	**97.3**	85.3	89.4	87.3	90.2	82.0
Total Firm Fixed Price ($000s)		▮▮	▮▮▮▮▮▮				▮▮

An RFQ has been issued by Commercial Management for labor to install the catalysts. The technical and commercial evaluations were completed by the plant proponents and commercial managers. ▮▮▮ was the recommended bidder.

Labor ($000s):	▮▮▮▮▮▮▮▮▮▮
Material ($000s):	▮▮▮▮▮▮▮▮▮▮
Equipment ($000s):	▮▮▮▮▮▮▮▮▮▮
Other ($000s):	▮▮▮▮▮▮▮▮▮▮
Total Cost ($000s):	▮▮▮▮▮▮▮▮▮▮

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	832	1,161	-	-	1,993
2. Cost of Removal Proposed	-	500	-	-	500
3. Total Capital and Removal Proposed (1+2)	832	1,661	-	-	2,493
4. Capital Investment 2017 BP	832	1,661	-	-	2,493
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	832	1,661	-	-	2,493
7. Capital Investment variance to BP (4-1)	-	500	-	-	500
8. Cost of Removal variance to BP (5-2)	-	(500)	-	-	(500)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$0
Contract Labor:	$358
Materials:	$1,670
Local Engineering:	$30
Burdens:	$208
Contingency:	$227
Reimbursements:	($0)
Net Capital Expenditure:	$2,493

- **Assumptions**

  Recommendation
    - o This option allows the unit to continue operating as normal.
    - o No cost savings or incremental costs are incurred.
    - o Capital spend occurs only in 2017 and 2018.
      - ▪ Cost estimates are based on catalyst bids and historical costs for similar projects completed.

  Alternative 1: Delay until 2019
    - o The project cost increases 2.5% per year due to inflation.
    - o There will be four unplanned outages in 2018 and one in 2019 to clean air heater baskets.
    - o The probability of outages in 2018 and 2019 is 50% and 60% respectively.
    - o The cost of a three-day outage is $256k per the corporate capital evaluation model standard calculation of lost availability for Ghent 1.
    - o O&M cost of an air heater cleaning is $25k.
    - o Cost of additional NOx credits that would likely be required to meet emissions targets was not included in evaluation.

  Alternative 2: Do Nothing
    - o There will be four unplanned outages per year to clean air heater baskets.
    - o The probability for forced outages starts at 50% in 2018 and increases by 10% each year as the catalyst becomes more deactivated. The probability reaches a maximum of 90% in 2022.
    - o The cost of a three-day outage is $256k per the corporate capital evaluation model standard calculation of lost availability for Ghent 1.
    - o O&M cost of an air heater cleaning is $25k.
    - o Cost of additional NOx credits that would likely be required to meet emissions targets was not included in evaluation.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes, layers 1 and 3 were replaced with regenerated layers in 2016
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

The Ghent Environmental Coordinator has signed off on this project.

- **Risks**

The risks of *not completing* this project include:

- o Forced NO_x Credit Purchase: Failure to meet NO_x reduction rates will require the company to purchase NO_x credits at the current market price. The risk associated with this is significant volatility in the NO_x credit pricing.
- o Non-Compliance with Cross-State Air Polution Rule: Beginning in May 2017, all units will be required to lower emissions during the ozone season.
- o Unplanned Outages: Without the replacement of the catalyst layer in GH1 SCR, the level of un-reacted ammonia will increase. This ammonia will be available to form ammonium bisulfate in the air heater. This sticky deposit will build up over time and require a unit outage for air heater cleaning; it is also corrosive and can add

significant O&M repair costs over time. This cost is included in the capital expenditure though
model (CEM).

The risks associated with *completion* of this project outside the optimal window:

- o Catalyst Performance: While past experience at other units has proven catalyst reliable, catalyst formulas are customized for the unit needs and there is a small risk that the formula will not perform as guaranteed.
- o Schedule: The catalyst will be installed during a planned maintenance outage of the unit. Any delay in the project will extend the outage, impacting the outage rate of the unit and potentially increasing the cost of the project.
- o Increased NOx emissions. The SCR will be required to operate at reduced efficiency in order to limit ammonia slip. As the NOx removal efficiency decreases the NOx emissions will increase and the company could be required to purchase NOx credits for compliance.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the GH1 SCR Catalyst L3 New project for $2,493k to allow the SCR to operate at the target efficiency.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: June 28, 2017

Project Name: GH2 4kv Switchgear Replacement

Total Expenditures: $7,495k (Including $681k (10%) contingency)

Project Number(s): 144302

Business Unit/Line of Business: Generation

Prepared/Presented By: Ritchie Chambless

Executive Summary

The scope of this project is to replace the Ghent Unit 2 (GH2) forty year old Federal Pacific 4kv switchgear during the 2019 eight week major outage to improve safety and increase the short circuit rating of the switchgear. New replacement switchgear lead time is approximately 24 months.

The existing switchgear design requires the Operator to be inside the switchgear cubicle when racking the breaker with a manual lever. Operators are required to wear a 100 calorie arc flash suit when racking the breakers, but they can still be severely injured when an arc flash occurs because they are so close to the arc flash energy. The new arc resistant switchgear will include bus differential protection and a reliable closed door remote racking system that significantly reduces Operator exposure to an arc flash incident. In the event that an arc flash occurs, the arc resistant switchgear will exhaust the arc flash energy to the outside of the building away from the Operator.

In 2013, during the design phase of the GH2 Bag House Project, it was discovered that the close and latch rating of the existing feeder breakers will be exceeded by approximately 23% if Unit 1 Reserve Auxiliary Transformer (RAT1) is used to start-up Unit 2 in the event Unit 2 Reserve Auxiliary Transformer (RAT2) fails. The short circuit close and latch rating of the new switchgear feeder breakers will be increased to 130 kilo-amperes (130ka) to ensure Unit 1 RAT1 can safely be used to start-up Unit 2 in the event RAT2 fails.

This project was included in the 2017BP at $8,007k through 2019. The timing change has resulted in higher spend projected in 2017 and lower spend in 2018 and 2019. Funding for the 2017 variance amount of $1,500k was approved by RAC in 3+9 forecast. Spending in 2018 and 2019 will be adjusted as part of the 2018 Business Planning process.

Background

The existing GH2 Federal Pacific (FPE) 4kv switchgear was installed in 1977 and consists of two buses labeled 2A and 2B with each bus consisting of one 3000A main breaker, one 3000A reserve breaker and eighteen 1200A feeder breakers. NFPA 70E requires our Operators to wear an arc flash suit rated a minimum of 100 calories when racking breakers due to the available short circuit fault current. The existing switchgear design requires the operator to be inside the switchgear cubicle when racking the breaker with a manual lever. If an arc flash incident occurs when lever racking a breaker, the Operator could be severely injured by being so close to the arc flash energy. Such an incident was experienced at Ghent Station in the 1990's when an Operator was severely injured while racking a GH2 4kv breaker. There are no safe and reliable remote racking systems on the market available for our FPE switchgear.

The GH2 FPE switchgear was retrofitted with replacement breakers in 1997, 2006, and 2010 to improve reliability. In 2013, during the design phase of the GH2 Bag House Project, it was discovered that the close and latch rating of the existing feeder breakers will be exceeded by approximately 23% if RAT1 is used to start-up Unit 2 in the event RAT2 fails. Project Engineering has worked with KBR to reduce the new RAT2 short circuit capability so the close and latch rating of GH2 4kv switchgear feeder breakers would be adequate during normal operation and start-up. The Ghent Bag House project team concluded the best solution was to replace the GH2 4kv switchgear at the earliest opportunity in order to safely use RAT1 as a backup for RAT2.

- **Alternatives Considered**
    1. Recommendation: NPVRR: $8,683k
    2. Alternative 1 – Do Nothing: NPVRR: N/A
       We will continue to place Operators in an unsafe situation when lever racking 4kv breakers. This is not considered a viable option given the Company's commitment to safety and meeting the operational performance metrics with the station.
    3. Alternative 2 – Retro-fill Exiting Switchgear   NPVRR: $8,864k
       This alternative requires replacing all the internal components in the existing switchgear cubicles which would increase the unit outage approximately two weeks. Operator arc flash exposure would be increased because existing switchgear cannot be converted to arc resistant switchgear. Retro-fill switchgear assembled on site would not be as high a quality as new switchgear assembled and tested at the factory.

Project Description

- **Project Scope and Timeline**

    The existing 4kv switchgear will be replaced with new arc resistant switchgear with matching footprint design, closed door remote racking system, bus differential protection, new electronic protection relays and on-line thermal monitoring for main bus, breaker line and load bus and feeder cable connections.

Plans are to replace the existing switchgear during an eight week unit outage that is currently scheduled to start September 30, 2019. Timeline milestones for the project are:

June 2017 – Project Approved
July 2017 – EPC Contract Awarded
Dec 2017 – Engineering and design 80% Complete
June 2018 – Switchgear Placed on Order
July 2019 – Factory Acceptance Testing Complete
Aug 2019 – Switchgear Delivered to Ghent Station
Sept 2019 – Switchgear Training Complete
Oct 2019 – Installation Begins
Nov 2019 – Installation & Commissioning Complete

- **Project Cost**

  Total estimated cost of the project is $7,495k with 10% contingency for labor and material included.

Economic Analysis and Risks

- **Bid Summary**

  Competitive bids were solicited from four firms with specialty expertise deemed capable of designing a workable replacement for the unusual 24 inch width Unit 2 switchgear. Three bidders submitted proposals, among which, two (▮▮▮▮▮▮▮▮▮▮▮▮▮▮) were short listed as being the best technically evaluated and/or lowest cost. Both short list proposals utilize the same Powell equipment so the differentiation between the two proposals, aside from pricing, lies largely in design expertise, experience, execution plan, and KU experience. After clarifications, both bidders were allowed to submit "best and final" offerings, which are represented in the table below. Although the bids show ▮▮▮▮▮ to be slightly lower cost than ▮▮▮, the normalized bid evaluation showed ▮▮▮ to have the lowest normalized cost. This is largely due to the number of engineering and start-up/commissioning hours allotted to the project by ▮▮▮. In summary, the evaluation team recognized a strong advantage to ▮▮▮ in terms of engineering expertise.

EPC Contract		
Equipment		
Engineering		
Construction		
Options		
Total		
Normalized Adders/Deducts		
Normalized Comparison		

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,650	2,311	3,274	-	7,235
2. Cost of Removal Proposed	-	-	260	-	260
3. Total Capital and Removal Proposed (1+2)	1,650	2,311	3,534	-	7,495
4. Capital Investment 2017 BP	150	4,177	3,420	-	7,747
5. Cost of Removal 2017 BP	-	-	260	-	260
6. Total Capital and Removal 2017 BP (4+5)	150	4,177	3,680	-	8,007
7. Capital Investment variance to BP (4-1)	(1,500)	1,866	146	-	512
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(1,500)	1,866	146	-	512

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Labor:	$ 305
Contract Labor:	$2,300
Materials:	$3,275
Local Engineering:	$ 83
Burdens:	$ 851
Contingency (10%):	$ 681
Reimbursements:	($0)
Net Capital Expenditure:	$7,495

RAC will provide the $1,500k additional funding in 2017. Spending in 2018 and 2019 will be adjusted in the 2018BP.

- **Assumptions**
    1. Alternative 2 – Retro-fill Existing Switchgear
        a. Budget Estimate = $6,600k
        b. Would need to add two weeks to the GH2 2019 major outage.

- **Environmental**

There are no local, state, or federal environmental requirements for permitting, notification, reporting, etc., regarding these repairs.

There are no known environmental isuses regarding this project.

	New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.	
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	No
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes, breakers have been replaced in 1997, 2006, and 2010.
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**

We risk severe injury and possible death to Operators if an arc flash incident occurs when lever racking a breaker. We will also risk a feeder breaker catastrophic failure if RAT1 is used to start-up GH2 in the event RAT2 fails.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the GH2 4kv Switchgear
Replacement project for $7,495k to improve safety and reliability.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the
members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the
signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: _May 30, 2017_

Project Name: _GH3 Burner Replacement_

Total Expenditures: $8,532k (Including 10% contingency of $775k)

Project Number(s): _133515_

Business Unit/Line of Business: _Generation__133515_

Prepared/Presented By: _Christina Schwind / Steve Turner_

Executive Summary

This project is to replace the existing Low NOx Burner Assemblies on Ghent Unit 3 with functionally equivalent new Low NOx Burner technology. Existing Overfire Air and Underfire Air Systems will be evaluated as part of the project as well. The existing Burner Assemblies have reached the end of their useful lives. These outdated Burner Assemblies are the source of a significant loss of operational control over the unit's firing system. This project consists of replacing all 24 existing Burner Assemblies with a new Low NOx Burner System.

A total of $2,400k was budgeted for 2024 and $6,100k in 2025 for this project in the 2017BP. Ghent Unit 3 will experience significant losses in operational control and an inability to manage the changing fuels projected for the future if the existing firing system is not replaced before 2025. The Corporate RAC approved $3,000k for 2017 in the 3+9 forecast. The $5,532k in 2018 will be reallocated from 2024/2025 as part of the 2018BP process.

Background

The existing Ghent Unit 3 ABT Opti-Flow Low NOx Burner Assemblies were installed in 1999 as part of a Low NOx Burner Upgrade project. Due to the design of the existing Burner Assemblies, the Secondary Air Damper and Swirl Vane linkages are prone to bind and break during normal operation. As a result there is significant loss of operational control within 48 hours of startup after a planned outage. During the fall 2016 outage it was discovered that four of the Burner Air Registers were internally damaged beyond repair. Severe damage was also found on 7 of the 24 coal nozzles at that time. After the fall 2016 outage, all Secondary Air Dampers and Swirl Vanes were placed in an optimum open position and remain in these positions throughout the range of operation. This action ensures that the dampers and swirls will not get stuck in light-off positions and cause further damage to the Burner Assemblies, but significantly limits ability to control combustion. The new burner design will allow for individual burner control across the load range, improving combustion management, emissions control, and better management of the burning of a broader spectrum of fuels. Replacing all 24

existing Burner Assemblies is necessary to regain operational control and continue to operate the Although generating unit safely and reliably.

- **Alternatives Considered**
  1. Replace all 24 existing Burner Assemblies on Ghent Unit 3 with functionally equivalent new low NOx burner technology.
       This is the best (recommended) option as it is the only option that is guaranteed to address all the current issues with the existing firing system.
       NPVRR: ($000s) $9,935k

  2. Do nothing.
       A quarter of the firing system on Ghent Unit 3 has been found to be severely damaged. Due to the design of the existing Burner Assemblies, the unit is currently being operated with limited combustion control. If these issues are not addressed, the unit will experience catastrophic damage to the firing system.
       NPVRR: ($000s) $14,924k

  3. Replace all 24 existing Burner Assemblies on Ghent Unit 3 with functionally equivalent new low NOx burner technology in 2025 as scheduled.
     a. This option does not address current issues with damaged air registers and will require significant maintenance above the current budgeted O&M.
     b. The risk of a windbox fire remains until the project is executed.
     c. Challenges with managing variable fuels remains until the project is executed
       NPVRR: ($000s) $11,916k

Project Description

- **Project Scope and Timeline**
  The scope of this project includes the engineering, procurement and construction required to replace the existing ABT Opti-Flow Low NOx Burner Assemblies on Ghent Unit 3 with functionally equivalent new low NOx Burner technology. The project also includes evaluating the existing Overfire Air and Underfire Air Systems for improvement or replacement. This project is similar to the GH4 Burner Replacement project in 2014. All four Vendors that were invited to bid the material supply for this project have experience designing and supplying similar technology on comparable generating units. Current unit drawings and operating parameters are being provided to the Vendors to ensure that the new system is sized and designed properly. Due to the duration of the Fall 2017 (3 weeks) and Fall 2018 (8 weeks) outages, only eight burners will be replaced in 2017 with the remainder in 2018.

  - April 18, 2017 – Formal bid specification issued to Vendors
  - May 16, 2017 – Bids due back for evaluation
  - May 30, 2017 – Investment Committee meeting and approval; Issue purchase order
  - June 2017 – Project kick-off, begin engineering and procurement

- October 2017 – Receive 8 Burner Assemblies and install during the fall planned outage
- November 2017 – Complete installation and commissioning of 8 Burner Assemblies
- December 2017 – Receive remaining 16 Burner Assemblies
- Spring/Summer 2018 – Bid fall 2018 installation labor
- Fall 2018 – Complete installation of 16 Burner Assemblies
- November 2018 – Begin commissioning and performance testing of new Burner System
- December 2018 – Project complete

- **Project Cost**
  The total cost of the project is $8,532k and includes 5% burdens and 10% contingency. The contingency amount was determined based upon the risk associated with the project and common contingency levels of projects of a similar size. The material supply for the project was bid as a lump sum. The supplemental labor contractor will perform the installation labor for the fall 2017 outage. The installation labor for the fall 2018 outage will be bid as a lump sum.

Economic Analysis and Risks

- **Bid Summary**
  Four Vendors ██
  were invited to bid the material supply for the project. Bid proposals are due Tuesday, May 16th. The installation labor for the fall 2018 outage will be issued for bid in 2018.

  Due to time constraints associated with receiving the installation drawings from the material supply Vendor, the supplemental labor contractor ██████████████ will be utilized for the fall 2017 installation. ██████████████ is familiar with the existing firing system on Ghent Unit 3 and has experienced personnel that were involved in the GH4 Burner Replacement project in 2014 and the Trimble County 2 Burner replacement.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	A Post through 2019	Total
1. Capital Investment Proposed	2,785	4,709			7,494
2. Cost of Removal Proposed	215	823			1,038
3. Total Capital and Removal Proposed (1+2)	3,000	5,532	-	-	8,532
4. Capital Investment 2017 BP				8,532	8,532
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	-	-	-	8,532	8,532
7. Capital Investment variance to BP (4-1)	(2,785)	(4,709)	-	8,532	1,038
8. Cost of Removal variance to BP (5-2)	(215)	(823)	-	-	(1,038)
9. Total Capital and Removal variance to BP (6-3)	(3,000)	(5,532)	-	8,532	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$160
Contract Labor:	$2,408
Materials:	$4,820
Local Engineering:	$0
Burdens:	$369
Contingency:	$775
Reimbursements:	($0)
Net Capital Expenditure:	$8,532

- **Assumptions**

  o Recommendation – Replace 24 Burner Assemblies
    The capital evaluation model assumes that we will purchase all 24 Burner Assemblies and complete installation of 8 Burner Assemblies in 2017. The model assumes that installation of the remaining 16 Burner Assemblies and commissioning of the new firing system will be completed in 2018.

  o Alternate #1 – Do Nothing
    The capital evaluation model assumes $200k/yr in unbudgeted OPEX to repair or replace the Burner Assemblies and outages based on burner damage and windbox fires. Improvements to the Overfire Air System were also not considered. Challenges burning future fuels was not taken into consideration. This alternative assumes a catastrophic failure in 2027 requiring an extensive capital investment.

o Alternate #2 – Replace 24 Burner Assemblies in 2025

The capital evaluation model assumes executing the project in 2025. The model assumes $200k/yr in unbudgeted OPEX to repair or replace the Burner Assemblies and outages based on burner damage and windbox fires until the project is completed. The pricing for the project in 2025 assumes 3% inflation rate.

• **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	Yes
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	Yes
	a. Provide frequency or when equipment or component in question was last repaired or replaced.	All 24 Burner Assemblies were modified to a hybrid design as part of a low NOx retrofit project in 1999.
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment?	No
	a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

• **Risks**

All Four material supply Vendors have experience designing and supplying comparable generating units with similar technology with good results. Improved combustion, reliability and operational control are expected with a high degree of certainty.

If this project is not completed the unit will experience significant loss of operational control of the firing system resulting in severe damage to equipment and increased derates and outages. As fuel supplies change over time there will be a reduced ability to deal with related combustion issues.

Conclusions and Recommendation Arbough

It is recommended that the Investment Committee approve the GH3 Burner Replacement project for $8,532k to regain operational control and continue to operate Ghent Unit 3 safely and reliably.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Combined Investment Proposal for Investment Committee Meeting on: 11/28/2017

Project Name: GH3 Cooling Tower Complete Rebuild

Total Project Expenditures: $12,605k   (Including $600k or 5% contingency)

Contract Total Seeking IC Approval: ███████
Total Contract Expenditures: ██████

Project Number(s): 194GH

Business Unit/Line of Business: Generation

Prepared/Presented By: Steven Straight/Steven Turner

Executive Summary

The fourteen cell Ghent Unit 3 cooling tower began operation in 1981. Cells 9 through 14 were rebuilt with wooden structures from 2002-2004 and the remaining 8 cells were replaced with polyester fiberglass structures from 2005-2009. Following the collapse of cells 2 and 3 in the Ghent Unit 4 cooling tower during the summer of 2016, thorough inspections of all cooling towers were conducted. The inspections revealed several failed columns in Units 1, 3 and 4. Unit 3 had over fifty structural columns which had failed throughout the 8 fiberglass cells on the cooling tower. The excessive failures caused the replacement strategy to be revised to a complete rebuild rather than the previous cell-by-cell replacement strategy which was in the 2017BP.

This project is for the complete rebuild of the Ghent Unit 3 cooling tower. The scope of this project includes the engineering, fabrication, procurement, demolition, construction and testing required to replace the entire Unit 3 cooling tower. In addition to the full replacement of the tower, the circulating water distribution piping will be re-located from the top of the cooling tower to the ground, which decreases the weight the structure is required to support.

The 2018BP includes $10,929k and reflects the change from a cell-by-cell rebuild strategy to the complete tower rebuild. The project was bid as a turnkey project including the engineering, demolition, fabrication, procurement, management, construction and testing required to complete the work. The lowest bid, which is the recommended proposal plus a 5% contingency, requires the current proposed amounts of $1,260k in 2017 and $11,345k in 2018. Funding for this project in 2017 was requested from the Resource Allocation Committee (RAC) and submitted as part of the 2017 9+3 forecast. $10,929k of the $11,345k amount for 2018 has been requested as part of the proposed 2018 Business Plan. The $416k incremental spend in 2018 will be funded internally from other Ghent projects.

Background

The fourteen cell Ghent Unit 3 cooling tower began operation in 1981. The original tower was a 14 cell wooden tower designed and constructed by Ecodyne. Starting in 2002 and continuing through 2003, cells 9 through 14 were rebuilt with wooden structures. The remaining 8 cells were replaced with polyester fiberglass structures between 2005 and 2009.

The cooling tower is inspected annually and areas of concern are noted and corrected to ensure the reliable operation of the cooling tower for the next year. Typically the cooling tower fill material, which occupies nearly all of the internal volume of the tower, is not removed and the inspection focuses on the external and mechanical areas. Following the collapse of cells 2 and 3 in the Ghent Unit 4 cooling tower during the summer of 2016, a thorough inspection of the Unit 3 cooling tower was conducted which required the removal of portions of the fill. The inspection revealed 54 structural columns that had split at the corners and failed throughout the 8 fiberglass cells.

Since the collapse of several cells on the Unit 4 cooling tower, the plant has conducted a thorough inspection and removed fill material from cells in order to inspect the columns which typically cannot be seen. The thorough inspections have identified several split columns and helped to revise the station's cooling tower replacement strategy from individual cell replacements to more comprehensive rebuild projects which include the mechanical and piping components.

This project includes demolition of the entire existing cooling tower, installation of a new cooling tower structure, new mechanical equipment, moving the large distribution piping from the top of the structure to the ground, new electrical and control cables, variable frequency drives for the fan motors and third party testing of the new tower's thermal performance. A comprehensive rebuild project, such as this project for Ghent 3, will help prevent future failures resulting in forced outages, and ensure plant personnel remain safe while on or in the cooling tower.

- **Alternatives Considered**

    1. Recommendation: Complete Rebuild   NPVRR: ($000s) $14,334

    2. Alternative #1: Do Nothing   NPVRR: ($000s) $16,907
       [This alternative should not be chosen because the Unit 3 cooling tower has exhibited signs of damage throughout the structure and poses a risk to operations and personnel safety.]

    3. Alternative #2: Rebuild Cell-by-Cell   NPVRR: ($000s) $14,719
       [This alternative should not be chosen due to project costs greater than the recommendation. In addition, this option does not provide the benefit of relocating the distribution piping to grade. Also, this alternative would delay the completion of the replacement several years allowing the Unit 3 cooling tower to further degrade and continue to pose a risk to operations and personnel safety.]

Project Description

- **Project Scope and Timeline**

  The scope of this project includes the engineering, demolition, procurement, management, construction and testing required to replace the entire Unit 3 cooling tower and the engineering, procurement and installation required to install the circulating water distribution piping at grade.

  Milestones:
  - November 2017 – Investment Committee meeting; Project approval
  - December 2017 – Issue purchase order; Project kick-off
  - May 2018 – Fabrication and procurement
  - June 2018 – Mobilize to site
  - September 2018 – Begin 2018 Outage work
  - November 2018 –Complete 2018 Outage work; Mechanical Completion
  - December 2018 – Complete Punchlist items; Final Completion
  - July 2019 – Performance Testing Completion

- **Project Cost**

  This project is expected to cost a total of $12,605k. The material cost is estimated to be $6,489k and the labor is estimated at $4,198k. Burdens are estimated to be $1,318k. Contingency (5%) is $600k and is reasonable given the current level of inspection and engineering work. The base scope will be awarded as lump sum and any additional work discovered during the project will be completed on a lump sum, unit price, or time and material basis.

- **Contract Description**

  The total value of this firm, fixed contract is ▮▮▮▮▮▮ including ▮▮▮▮ of contingency. All installation work is scheduled to be completed by November 17, 2018. Contract provisions include performance guarantees supported by liquidated damages, liquidated damages for schedule delay, a parent guarantee by ▮▮▮▮▮▮▮▮, and a final milestone retention payment. All Work will be governed by a negotiated General Commercial Agreement between LG&E and KU Services Company and ▮▮▮▮▮▮▮.

Economic Analysis and Risks

- **Bid Summary**

The request for proposal (RFP) was issued to two contractors specializing in this type of work: ▮▮▮▮▮▮▮▮▮▮▮▮▮▮ and ▮▮▮▮▮▮▮▮. A pre-bid meeting was conducted on August 8, 2017. Both solicited bidders returned a bid by the due date, September 7, 2017.

In addition to pricing, proposals were evaluated based on technical approach, proposed warranty and liquidated damages, conformity to the scope of work, proposed material suitability, experience, commercial terms, and safety. Overall, ████████ was found to have the preferable bid (see Bid Pricing Comparison below) based on input from the Commercial, Maintenance, Operations, and Planning Departments. The ████████ proposal is fully compliant with both the scope and schedule. It includes significant schedule liquidated damages, a make right performance guarantee to be verified by third party performance testing, as well as a 10 year material and workmanship warranty on the structure and a five year material and workmanship warranty on the mechanical equipment.

- **Bid Pricing Comparison**

Pricing Sheet	
Item #	Item Description
1	Engineering Labor
2	Removal Labor
3	Installation Labor
4	Equipment/Consumables
5	Material
6	Freight
7	Option 1 Pricing: 100% of the basin is utilized
8	Option 2 Pricing: Sparger pipe
9	Option 3 Pricing: VFD Purchase and Install
10	Option Pricing: Geotechnical Investigation
11	Warranty - 10 years on structure, 5 years on mechanic
12	Recommended Spare Parts
	TOTAL BASE BID
	TOTAL OPTIONS BID
	TOTAL AWARD AMOUN
Adders to make bid compliant with scope	
Adder 1	**Liquidated Damages for Schedule Delay***
Adder 2	**Seal edges of FRP structural members**
Adder 3	**Adder for unpriced options**
Adder 4	**Performance Guarantee**
	TOTAL NORMALIZED COMPARISON
	Notes
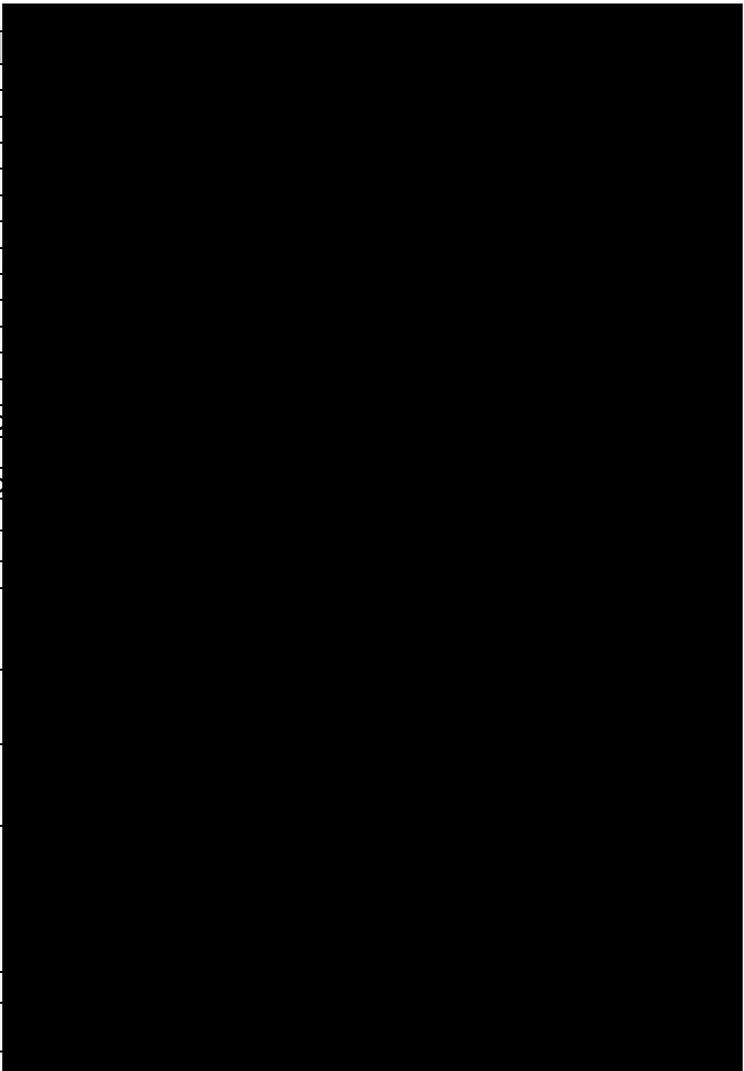
- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,260	10,923	-	-	12,183
2. Cost of Removal Proposed	-	422	-	-	422
3. Total Capital and Removal Proposed (1+2)	1,260	11,345	-	-	12,605
4. Capital Investment 2018 BP	-	10,929	-	-	10,929
5. Cost of Removal 2018 BP		-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	-	10,929	-	-	10,929
7. Capital Investment variance to BP (4-1)	(1,260)	6	-	-	(1,254)
8. Cost of Removal variance to BP (5-2)	-	(422)	-	-	(422)
9. Total Capital and Removal variance to BP (6-3)	(1,260)	(416)	-	-	(1,676)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 4,198
Materials:	$ 6,489
Local Engineering:	$ 0
Burdens:	$ 1,318
Contingency:	$ 600
Reimbursements:	$ (0)
Net Capital Expenditure:	$12,605

- **Assumptions**

The Capital Evaluation Model contains the following assumptions:
  - o An availability disimprovement of one week per cooling tower cell failure is assumed for Alternative #1 and increases by a quarter of a week each subsequent year. This is based on previous cell failures at the station and schedule information received with the bids.
  - o An availability disimprovement of one week per cooling tower cell failure is assumed for Alternative #2 and increases by a quarter of a week each subsequent year until half of the tower is rebuilt, then it decreases by a quarter week until the entire tower is rebuilt. This is based on previous cell failures at the station.
  - o Unbudgeted O&M Costs assumed for both alternatives are based on previous repairs related to the cooling tower structure and mechanical equipment.

o Alternative #2 assumes the cooling tower cells will be replaced cell-by-cell over a through years, as was the case in previous business plans. Costs for new mechanical equipment have been added.

o Alternative #2 does not include costs to re-route the circulating water, install variable frequency drives for the fan motors, install new power cabling, install vibration monitoring equipment or perform third party performance testing.

- **Environmental**

Kentucky State Demolition Permit will be submitted.

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes; See Background section
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**

If this project is not completed during the 2018 Unit 3 fall outage, continued degradation of the cooling tower structure will occur which will increase the potential risk of having a structural failure which would affect the unit's ability to produce energy. The 2018 Unit 3 outage is a major turbine overhaul, which gives enough time for the proposed work. Ghent 3 does not currently have another outage of sufficient duration planned until 2025.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the GH3 Cooling Tower Rebuild
project for $12,605k and the GH3 Cooling Tower Rebuild contract to ███████████ for
███████ to ensure long term relability and safety of the Ghent 3 cooling tower.

**<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million and
Contract Authority Greater Than or Equal to $10 million bid, or $2 million sole sourced</u>:**

The Capital project spending and contract authority requests included in this Investment Proposal
have been approved by the members of the LKE Investment Committee. Pursuant to the LKE
Authority Limit Matrix, the signatures below are also required for approval of this Capital
project spending and contract authority request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
GH3 Cooling Tower

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the GH3 Cooling Tower Rebuild contract to ███████████ for ████████.

Sourcing Leader Jared Kelley Contract Administrator, Ghent		Proponent Steven Straight Civil Engineer, Ghent	
Supplier Diversity Manager	N/A	Manager Brad Pabian Manager - Enginereing and Technical Services, Ghent	
Commercial Operations Alex Betz Manager - Commercial Operations, Ghent		Commercial Operations Joe Clements Director – Power Gen. Commercial Operations	
Director Steve Turner General Manager, Ghent		Vice President Ralph Bowling VP Power Production	

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: <u>July 26, 2017</u>

Project Name: <u>GH3 Primary SH Tube Repl</u>

Total Expenditures: <u>$4,047k (Including $368k, or 10% contingency)</u>

Project Number(s): <u>131980</u>

Business Unit/Line of Business: <u>Ghent Generating Station / Power Generation</u>

Prepared/Presented By: <u>Stephen Nix / Steve Turner</u>

Executive Summary

This project is for replacement of the Primary Superheater in the furnace backpass of Ghent Unit 3. The scope of this project includes the design and supply of new assemblies and removal and installation during the fall 2018 outage. This boiler section is planned to be replaced simultaneously with both the Upper Economizer Upper Bank (Project 144311) which is situated directly below in the same boiler gas backpass and the Vertical Reheater (Project 155008) which is situated directly above. Materials for all three projects will be designed and fabricated by the same supplier with installation by the same contractor. The Primary Superheater is original tubing. There are design issues with tube support connections (solid ties) which have caused numerous leaks over the past two decades. This condition will continue to get worse with age of the assemblies. This project is being recommended in accordance with the Ghent Boiler Reliability Plan.

Tubing material supply for this project has been sourced using an aggregated competitive bid strategy with the two other large boiler projects mentioned above. The contract for erection is being awarded under the Boiler Craft Labor 2017-2018 contract initiative. ██████████ is the selected bidder for material and ████████████████████ for installation labor.

This project is in the 2017 BP for $3,661k. The incremental 2017 funding was from internal reallocations. The incremental 2018 funding will be requested as part of the 2018 business planning process to be completed later this year.

Background

The Primary Superheater has been in service since startup in 1981. The Primary Superheater is constructed mostly of low alloy carbon steel tubing. Harsh operating conditions in the superheat front backpass have caused tube leaks due to flyash erosion and failures with the tube assembly alignment system. Alignment system failures and related support lug disengagements have led

to fatigue cracking at solid tube ties causing most of more than thirty leaks since 1995. Although original stainless steel alignment system was eventually replaced with a modified design.

The goal of this project is to replace the Primary Superheater and to use an improved design for better alignment and support. The improved design will keep tubes aligned and support lugs engaged to avoid fatigue cracking at solid tube ties. Proposed support systems will reduce or eliminate the use of solid ties in favor of other support mechanisms. Tube shields will be installed to protect from flyash and sootblower erosion. The result of these improvements will be fewer forced outages from tube failures. Also, reduction in the number of different material grades and wall thickness in the primary superheater will be considered to save on fabrication costs and plant tube inventory.

- **Alternatives Considered**

    1. Recommendation: NPVRR: ($000s) $ 4,598
       Execute this project by replacing the Primary Superheater in 2018.

    2. Alternative #1:   NPVRR: ($000s) $ 7,139
       Delay replacement until the next major outage in 2025.
       Forced outages to be expected until implemented. Manage the risk of forced outages with more inspections, tube shielding, dutchmen, pad welding and repairs. Mobilization and unit access costs will be higher for this project and for the Upper Economizer Upper Bank replacement (Project 144311) if not performed during the same outage.

    3. Do Nothing: NPVRR: ($000s) $10,949
       Continue operation and maintenance without replacement.
       Forced outages to be expected to continue. Manage the risk of forced outages with more inspections, tube shielding, dutchmen, pad welding and repairs. Mobilization and unit access costs will be higher for Upper Economizer Upper Bank replacement (Project 144311).

The project cost evaluation shows it is more beneficial to replace the Primary Superheater in 2018 than it is to either delay replacement until the next major outage in 2025 or to Do Nothing and continue operation and maintenance without replacement while risking forced outage leak repairs.

Project Description

- **Project Scope and Timeline**

The Primary Superheater replacement will take place during the fall 2018 outage. The installation work was included in the Boiler Craft Labor 2017-2018 contract initiative. Installation bids were solicited from ten contractors in July 2016. ▆▆▆ is being awarded installation work for the Ghent 2018 outage. Bids for materials were solicited from seven boiler

pressure part suppliers in late January 2017, six of which submitted bids. ███████ is being although awarded the material supply for this project.

Operational and maintenance issues with the existing assemblies have been shared with the bidders to get more focused proposals. An improved design for the support and alignment system with a higher temperature grade of stainless steel and Inconel alignment straps has been specified. The specification has requirements for the location and gauge of tube shields and details for attachment to the tubes. Tube cut points have been selected to facilitate erection. The base bid was for in-kind tube materials. Bidders were permitted to offer alternate materials to consolidate the supply into fewer material changes and fewer shop welds. Various material changes will be implemented with the award to ██████████.

Milestones:
- July 2017 – Investment Committee meeting and approval
- July 2017 – Issue material purchase order
- August 13, 2018 – Material received
- September 24, 2018 – Outage Start Date
- November 18, 2018 – Complete Outage work

- **Project Cost**

    The cost for this project is $4,047k which includes 10% contingency for KU purchased materials and installation labor.

Economic Analysis and Risks

- **Bid Summary**

    Bid Summary (Installation): ██████████████ will be awarded the installation for the firm price of $1,737k based on prior approval on the Boiler Craft Labor 2017-2018 contract initiative.

    Bid Summary (Material Supply): Material for this project will be awarded to ██████████. The tubing material was sourced using an aggregated competitive bidding strategy, illustrated by the table below.
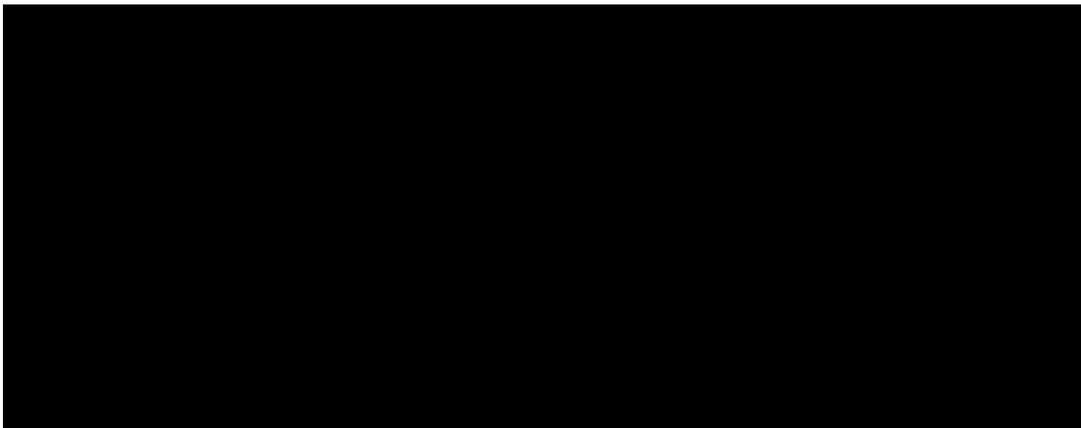
- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	318	3,358			3,676
2. Cost of Removal Proposed		371			371
3. Total Capital and Removal Proposed (1+2)	318	3,729	-	-	4,047
4. Capital Investment 2017 BP	104	3,229			3,333
5. Cost of Removal 2017 BP		328			328
6. Total Capital and Removal 2017 BP (4+5)	104	3,557	-	-	3,661
7. Capital Investment variance to BP (4-1)	(214)	(129)	-	-	(343)
8. Cost of Removal variance to BP (5-2)	-	(43)	-	-	(43)
9. Total Capital and Removal variance to BP (6-3)	(214)	(172)	-	-	(386)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 23
Contract Labor:	$ 2,410
Contract Materials:	$ 985
Burdens:	$ 261
Contingency:	$ 368
Reimbursements:	($0)
Net Capital Expenditure:	$ 4,047

- **Assumptions**

The Capital Evaluation Model contains the following assumptions:
  - 10% contingency and burdens have been included in capital investment costs.
  - Availability Disimprovement (AD) probability is based on 3 forced outages per year and progressively becoming more frequent. Forced outages last 1.5 days each. AD probability is based on historical leaks with age factored.
  - Reduced incremental cost is based on $19k to fix leaks, $130k unit startup cost and $50k preventive maintenance (PM) on assemblies per year. Forced outage maintenance and startup costs are factored based on the AD probability above.
  - 3% inflation assumed per year.
  - Alternative #1 is to delay the project 7 years until the next major outage in 2025.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes Annual
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	Yes

8a.   GADS data shows leaks on 5/24/2012, 1/25/2014 and 7/1/2016.

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**

Choosing one of the alternatives such as not implementing the tube replacement project or delaying the work until the next major outage will lead to forced outages and will have a negative commercial availability impact.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the GH3 Primary Superheater Tube Replacement project for $4,047k to avoid forced outages and to maintain the reliability of Ghent Unit 3.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: <u>July 26, 2017</u>

Project Name: <u>GH3 Partial Vertical RH Repl - 2018</u>

Total Expenditures: <u>$3,553k</u>   (Including $323k, or 10% contingency)

Project Number(s): <u>155008</u>

Business Unit/Line of Business: <u>Power Generation</u>

Prepared/Presented By: <u>Ben Zeigler</u>

Executive Summary
The project scope includes the purchase and installation of nineteen vertical reheater tube assemblies for the Ghent Unit 3 boiler. This component has experienced three boiler tube failures in recent years and the rate of failure is expected to increase if repairs are not made. This project will eliminate the sections of tubing that are most affected by corrosive attack. The corrosion is a derivative of high tube temperatures and elevated chlorine content in fuel.

The new reheater assemblies will replace the front and rear portions of the vertical reheater and include all support loops that extend into the penthouse. All assemblies will be fabricated with 304H stainless steel tube material to combat the advanced corrosion. This design will mirror existing elements in this area that are not showing signs of degradation. This change in material selection will not alter the geometry and will have no effect on the overall boiler heat input or combustion process.

This component was replaced in 2003 with additional surface area as an attempt to balance steam temperatures at the time of a selective catalytic reduction equipment addition, burner replacement, and waterwall refractory removal. After experiencing the first tube failure in June of 2015, increased inspection efforts and localized repairs were made to extend the life of this component until a larger scale project could be planned. In order to mitigate future risk of tube failures in this component, it is recommended to replace nineteen assemblies during the fall 2018 outage. This project is being recommended in accordance with the Ghent Boiler Reliability Plan.

Tubing material supply and labor for this project has been sourced using an aggregated competitive bid strategy with two other large boiler projects scheduled for fall 2018 outage.

The project was not included in the 2017 business plan, but is being recommended as a result of recent tube failures and inspections. Funding for this project in 2017 was authorized by the Resource Allocation Committee (RAC) as part of the 2017 5+7 forecast. The 2018 proposed amounts will be requested as part of the 2018 business planning process to be completed later this year.

Background

When this component was replaced in 2003, twenty-four assemblies were made of stainless steel material. These were strategically placed in two separate zones of the boiler that were known to operate at higher temperatures. The other thirty-nine assemblies were made of low alloy carbon steel tubing. The areas just outside of these stainless zones are now experiencing coal ash corrosion due to high tube temperatures and chlorine content. In conjunction with a separate project for the fall 2017 outage, the overall project scope includes twenty-nine new stainless assemblies, leaving ten alloy assemblies in the center of the unit. These are known to operate with cooler tube metal temperatures and current material condition does not warrant replacement.

This project is necessary to address the worst areas of corrosion attack. The existing tubing material is SA-213 T22 and has a chromium (Cr) content of 2.25%. The new assemblies will be fabricated with SA-213 TP304H, which contains up to 20% Cr that will better withstand the operating environment. Extensive inspections and repairs have been made to address this issue. One forced outage occurred due to a tube failure on this component in 2015 and two occurred in 2016. During the fall 2016 outage, twenty-one tubes were replaced in the worst areas, and more were pad welded as an effort to address the immediate need. Upgrading the tube material to stainless in this area will deliver long term protection against high tube temperatures and coal ash corrosion.

- **Alternatives Considered**
  1. Recommended replacement of 19 assemblies   NPVRR: ($000s) $4,022

  2. Defer project 5 years to 2023   NPVRR: ($000s) $6,401

  3. Do nothing. Repair leaks on O&M.   NPVRR: ($000s) $8,058

The recommended option is to replace nineteen assemblies during the fall 2018 outage. This is in conjunction with a separate project to replace an additional ten assemblies during the fall 2017 outage. Alternatively, deferring the project five years to 2023 was also considered. The observed material condition of the tubing provides confidence that the tubing will not last until 2023 without a significant EFOR impact. The risk of tube failures and continued O&M spend will increase substantially if no major replacement is made.

Project Description   **Arbough**

- **Project Scope and Timeline**
  The scope of this project includes a material upgrade to combat high tube temperatures and coal ash corrosion.

  - 07/26/2017   Project presented for approval before the IC
  - 08/03/2017   Issue purchase order for material
  - 08/03/2017   Issue purchase order for labor
  - 08/13/2018   Material delivered to Ghent for 2018 install
  - 11/16/2018   2018 Outage work complete

- **Project Cost**
  Total cost of the 2018 project is estimated to be $3,553k.

  There is a 10% contingency included with this estimate for both material and labor. Contingency considerations are for additional boiler inspection findings and rigging complication.

Economic Analysis and Risks

- **Labor Bid Summary**
  Labor for this project will be awarded to ████████████████ This project is a negotiated lump sum addition to the competitively bid boiler craft labor package that was issued during the fall of 2016. Two other major projects are being done simultaneously in the same area of the boiler. Due to restrictions and safety concerns, it is necessary for the same mechanical contractor to execute all scopes of work.

- **Material Bid Summary**
  Material for this project will be awarded to ████████ The tubing material was sourced using an aggregated competitive bidding strategy, illustrated by the table below.
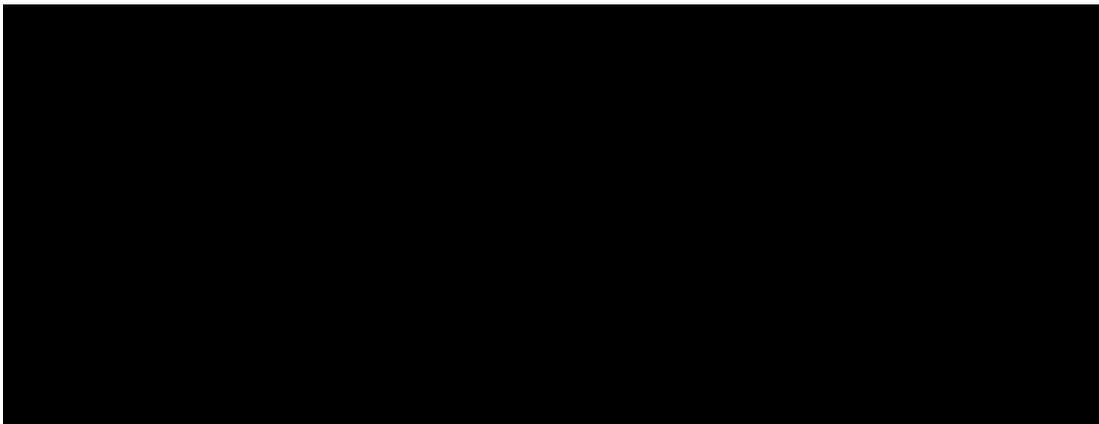
- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	135	2,956	-	-	3,091
2. Cost of Removal Proposed	-	462	-	-	462
3. Total Capital and Removal Proposed (1+2)	135	3,418	-	-	3,553
4. Capital Investment 2017 BP	-	-	-	-	-
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(135)	(2,956)	-	-	(3,091)
8. Cost of Removal variance to BP (5-2)	-	(462)	-	-	(462)
9. Total Capital and Removal variance to BP (6-3)	(135)	(3,418)	-	-	(3,553)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Note: This project has been included with the 2018 BP.

Financial Summary ($000s):

Discount Rate: 6.32%

Capital Breakdown:
Labor: $ 10
Contract Labor: $ 2,347
Materials: $ 681
Local Engineering: $ 32
Burdens: $ 160
Contingency: $ 323
Reimbursements: ($0)
Net Capital Expenditure: $ 3,553

- **Assumptions**
    1. Availability "disimprovement" was determined to be two three day (0.43 weeks) outages caused by boiler tube failures. An incremental increase in probability is assumed.
    2. Deferring the project to 2023 (alternative #2) assumes a 3% inflation rate and $168k spend is included in 2022 for a material procurement.
    3. Incremental costs are based on $130k for unit start up and $28k for tube failure repair. These costs are multiplied by the probability of disimprovement.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes 2003
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	*Yes

8a. GADS data shows leaks on 06-15-2015, 03-08-2016, and 09-22-2016.

The Ghent Environmental Supervisor and Environmental Affairs has reviewed and approved this project.

- **Risks**
  1. The most significant risks to this project are related to the project schedule. The location of these boiler components require complex rigging and difficult welds to be made.
  2. If this project is delayed, a significant EFOR impact may be realized.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the GH3 Partial Vertical Reheater Replacement - 2018 project for $3,553k to prevent future forced outages and maintain availability.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: 06/27/2018

Project Name: GH3 Waterwall Panel Replacement 2019

Total Expenditures: $2,127k   (Including $178k of contingency)

Project Number(s): 151366

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Benjamin Zeigler/Brad Pabian/Steve Turner

Executive Summary

The project scope includes the purchase and installation of shop fabricated waterwall panels with weld metal overlay for the Ghent 3 boiler furnace. This unit is of Foster Wheeler design with all burners located on the front and rear walls. These new panels will be installed near the combustion zone from the bottom burner elevation extending up above the overfire air elevation for a total height of 44 feet. The scope of this project includes a total of 144 tubes furnished in 20' and 24' panels for a total area of 3,048 sq ft. The new waterwall panels will include Inconel 622 weld metal overlay to increase corrosion resistance while burning Illinois basin coals that have increasing chlorine and sulfur content with a low NOx firing system. The installation of these panels is to be completed during the planned Ghent 3 fall outage in 2019. This project is being recommended in accordance with the Ghent Boiler Reliability Plan.

Competitive bids for tubing material have been solicited. The material order is ready to be awarded upon project approval. Mechanical installation labor will be sourced later this year.

The total project cost is estimated to be $2,127k. A total of $1,934k was included with the 2018BP. Due to changes in burden rates, a total of $1,927k was included with the proposed 2019BP. The additional $200k has been internally funded within the Ghent capital budget.

Background

The goal of this project is to prevent forced outages due to waterwall tubing corrosion that is accelerated by rising chlorine and sulfur content in fuels. The wall fired GH3 boiler has not historically been prone to fireside waterwall wastage, but based upon fleet and industry findings in the post wet flue gas desulfurization and low NOx era, increased efforts have been initiated to monitor the condition of waterwall boiler tubing. Historical tube failures on GH3 have been caused by mechanisms that were initiated from the internal surface of the tube. These issues have largely been addressed with smaller scale repairs, cycle chemistry adjustments, and chemically cleaning the unit. Beginning in 2011, inspections have revealed the tube wall thickness to be wasting away from the fire side of the tube and is now below the minimum wall thickness in some areas. Material thickness readings have indicated that the tubing targeted for replacement has lost approximately 30% of the original wall thickness.

The recent data has shown that large scale replacement projects need to be implemented in a phased approach to address the current (and predicted) condition of the furnace wall tubing. The material wastage rate is expected to increase proportionally with chlorine levels in fuels such as those from the Illinois #6 seam. As a company, we have targeted 25% of non-Powder River Basin burn to come from this seam. Our fleet as well as our industry has seen chlorine levels rise from 800-1200 ppm to 2000-2500 ppm and in some cases over 3000 ppm. This is the main driver for wall wastage rates as high as 0.050" to 0.080" per year.

The recommended weld metal overlay has a negligible effect on heat transfer and will not affect boiler efficiency. This project will not impact the dispatch order or the utilization of the unit. Completion of this project will support the reliable operation and prevent waterwall tube failures due to fireside corrosion.

- **Alternatives Considered**
  1. Recommended 2019 panel replacement   NPVRR: ($000s) $2,383k

  2. Field applied overlay of existing panels   NPVRR: ($000s) $2,451k

  3. Do Nothing   NPVRR: ($000s) $6,476k

The recommended option is to replace 3,048 square feet of furnace wall tubing surface during the 2019 fall outage. This is based on current tubing material condition as measured over the last several years to be below the minimum wall thickness. Two other options were considered as alternatives. The first of which was to apply weld metal overlay to the existing furnace wall in the field. This requires extensive surface preparation via grit blasting and eliminates the possibility of other work in the gas path. In addition to this, the field application process requires a minimum existing tube wall thickness prior to field applying weld metal overlay. There are likely several areas that are approaching this limit, which would require complete tube replacements. Lastly, if field applied weld overlay is selected, the potential safety and reliability benefits of replacing existing tubing with other defects will not be realized. As reflected in the capital evaluation model, doing nothing has a significant impact on EFOR.

Project Description

- **Project Scope and Timeline**
  The scope of this project includes the purchase and installation of furnace waterwall panels with weld metal overlay in zones of fireside corrosion.

  - 04/13/2018   Material bids received
  - 06/27/2018   Project presented to the Investment Committee for approval
  - 11/01/2018   Installation labor secured (as part of aggregated fleet bidding effort)
  - 10/04/2019   Panels due on site
  - 11/04/2019   Outage work begins
  - 11/27/2019   Project complete

- **Project Cost**   **Arbough**
  Total cost of the project is estimated to be $2,127k. There is an 8% contingency included with this estimate for labor. The labor estimate for this project is based on other projects of similar nature and budgetary estimates from craft labor contractors. Also included in this project estimate is funding for scaffold access to the waterwalls. The total cost of this boiler scaffolding will be shared with funds in the O&M outage budget due to the need for normal inspection access. These costs were estimated from previous work of the same scope. Material and labor will be secured via a firm fixed price contract.

Economic Analysis and Risks

- **Labor Bid Summary**
  Budgetary labor estimates have been received for project development. Labor for this project will be sourced later this year.

- **Material Bid Summary**
  Material for this project will be awarded upon approval of the project. Competitive bids have been solicited from 7 suppliers and 5 were received on 04/13/2018. Due to long lead times, potential impacts of tariff changes, and anticipated increases in nickel prices, expedited procurement is attractive.

	▆ ▆	▆▆▆	▆	▆	▆▆ ▆ ▆	▆▆ ▆	▆▆
Total Cost ($000s)	▆	▆	▆	▆▆▆▆▆▆▆▆▆▆▆			

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	200	1,675			1,875
2. Cost of Removal Proposed		252			252
3. Total Capital and Removal Proposed (1+2)	200	1,927	-	-	2,127
4. Capital Investment 2018 BP		1,870			1,870
5. Cost of Removal 2018 BP		64			64
6. Total Capital and Removal 2018 BP (4+5)	-	1,934	-	-	1,934
7. Capital Investment variance to BP (4-1)	(200)	195	-	-	(5)
8. Cost of Removal variance to BP (5-2)	-	(188)	-	-	(188)
9. Total Capital and Removal variance to BP (6-3)	(200)	7	-	-	(193)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s): **Arbough**

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$9
Contract Labor:	$1,142
Materials:	$671
Local Engineering:	$0
Burdens:	$122
Contingency:	$183
Reimbursements:	($0)
Net Capital Expenditure:	$2,127

- **Assumptions**

1. For all future costs, a 3% inflation rate was used.
2. The availability disimprovement was determined to be a three day (0.43 weeks) outage caused by a boiler tube failure. An incremental increase in probability is assumed.
3. The alternative case for applying weld metal overlay in the field includes a 20% probability of a tube failure for the first two years after the project is completed. This is based on the assumption that the welding process applied to the large area on the existing furnace wall will add risk in the short term. This process can create defects in the existing tube material that may not be detected due to the inability to perform a hydro test.
4. For the "do nothing" alternative, the duration of the availability disimprovement is increased in future years to reflect multiple boiler tube failures.
5. Incremental costs are based on $130k for unit start up, $28k for tube failure repair, and $15k for boiler deslag. These costs are multiplied by the probability of disimprovement.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	Yes 1990's*

	a.	Provide frequency or when equipment or component in question was last repaired or replaced. * Replacement panels from the early to mid-1990's were driven by internal corrosion issues. The scope of this project addresses an external damage mechanism in different areas.	**Arbough**
#8		Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project. * 6/13/2015 – Waterwall tube leak	Yes

The Ghent environment supervisor has reviewed and approved this project.

- **Risks**
  1. If this project is delayed, there will be an increased EFOR risk.
  2. This project is targeted to replace known areas of corrosion. There are likely areas outside of these zones that will need to be addressed with similar projects in the future. Such projects are included with the proposed 2019BP for 2022 and 2025.
  3. The timeline for this project is limited. There is a risk that complications with the material delivery or mechanical installation can extend the length of the planned 2019 outage. This risk will be addressed with firm contractual milestones and associated liquidated damages. Also, the mechanical contractor bidder list for this project has been qualified using metrics for quality, safety, and recent projects of similar scope.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the GH3 Waterwall Panel Replacement project for $2,127k to prevent future forced outages and maintain availability.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:
Kent Blake
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Kent W. Blake   Date
Chief Financial Officer

6/28/2018 | 1:26 PM PDT

DocuSigned by:
Paul Thompson
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Paul W. Thompson   Date
Chairman, CEO and President

6/28/2018 | 2:29 PM EDT

Investment Proposal for Investment Committee Meeting on: August 29, 2018

Project Name: GH4 PJFF Bag Replacement 19

Total Expenditures: $2,337k   (Including $212k of contingency)

Project Number(s): 135284

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Jen Price / Brad Pabian / Steve Turner

Executive Summary

The project scope includes the purchase and installation of fabric filter bags for the Ghent Unit 4 (GH4) pulse jet fabric filter (PJFF), which contains 17,280 bags. The scope also includes the removal and disposal of used bags, inspection of various pulse air components, replacement of all top hatch door gaskets, and a fluorescent powder leak test to verify proper installation. The proposed work is to be completed during the 2019 GH4 planned spring outage.

In order to continue to meet particulate matter (PM) emissions limits set forth by the Environmental Protection Agency (EPA), it is recommended to replace the fabric filter bags in 2019 before bags begin to fail. Once bag failure occurs, it will continue at an exponential rate and ultimately cause forced outages due to not being able to maintain PM compliance.

If bags are not replaced during the 2019 spring outage, the unit runs the risk of forced outages. If the project is continuously delayed, the probability of forced outages increases each year. The option to change bags in select compartments upon failure not only jeopardizes unit reliability, but also decreases the life of new bags due to the majority of the gas flow going through the new, more permeable bags.

Competitive bids for the above scope have been received. Upon project approval and a detailed bid evaluation, the work will be awarded and material ordered as soon as possible due to a twenty (20) week lead time on the filter bags. The total project cost is estimated to be $2,337k. A total of $2,706k is proposed in the 2019BP. This project was originally proposed in the 2018BP to be completed in 2020, however, bag test results indicated the need to complete the project in 2019. The lower project cost estimate compared to the proposed 2019BP is a result of established bids and eliminating the purchase of new cages after conducting a thorough investigation on the condition of the current cages.

Background   Arbough

The Mercury and Air Toxics Standard (MATS) rule, published in 2012 by the EPA, established emission limits and requirements reflective of maximum achievable control technologies (MACT) for toxic air emissions. In order to assure continuous compliance with the standards set forth within the rule, additional technologies were implemented at each coal-fired generating station within the Louisville Gas & Electric and Kentucky Utilities (LG&E-KU) fleet to allow further flexibility beyond what was currently in place. This included the addition of PJFFs on all four (4) units at Ghent for filterable particulate control.

The Ghent Unit 4 PJFF, designed by Clyde Bergemann Power Group, has been in service since December 2014. The PJFF is comprised of two casings (4-1 and 4-2) each containing ten compartments. Each compartment holds 864 filter bags, totaling 8,640 bags per casing, and 17,280 bags for the entire system. The filter bags, which are woven fiberglass finished with an acid resistant polytetrafluoroethylene (PTFE) membrane, serve as the filtering medium for the boiler flue gas. Each bag is 6" in diameter and 26'-9" in length.

Beginning in the spring of 2016, in-service bags have been sampled from Ghent 4 during unit outages. Third party testing has been performed in order to establish and monitor the bag life cycle; twenty-eight (28) bags have been analyzed to date. In addition to sending off bags for analysis, a leak test utilizing fluorescent powder (identical to the original equipment startup activities) was conducted during the spring 2018 outage to identify bag failures. Although no failed bags were identified during the leak test, bag analysis results have shown lower than expected endurance/durability values which has increased concern regarding remaining bag life.

Since the condition of the cages has been a concern since the start of the bag testing program, an analysis was conducted on the carbon steel cages, which are inserted into each bag for structural support, in order to determine if the original condition of the cages was contributing to bag degradation. During the spring 2018 outage, four (4) cage samples were sent off for analysis, including two (2) used cage samples from the Unit 4 PJFF and two (2) original cage samples from the warehouse. Examination of the used cage samples revealed no evidence of any significant service-induced damage. In particular, there were no signs of measurable corrosion attack nor had any of the joints between the wires and rings separated. The metallurgical condition of the used cage samples was identical to that of the original cage samples. Based on the findings, the cage material (both as-received and service-exposed) would not be expected to affect the long-term performance of the bag material.

In order to ensure continued reliability of the unit, it is recommended to replace the filter bags during the next scheduled 2019 spring outage, while re-using the current cages. At that time, the bags will have been in service for 4 ½ years, reaching the expected 5-year life span. Installation of new bags will allow the unit to continue operating as necessary to comply with PM emissions limits.

- **Alternatives Considered**

  1. Recommendation: Purchase/Install New Bags   NPVRR: ($000s) $2,733
  2. Alternative #1: Delay Project One (1) Year   NPVRR: ($000s) $2,881
  3. Alternative #2: Do Nothing   NPVRR: ($000s) $11,447

  Recommendation – Purchase/Install New Bags
  The purchase and installation of new bags in 2019 is the recommended option. This plan is least cost over the life of the project, avoids the probability of unit outages, and ensures PM emissions compliance.

  Alternative #1 – Delay Project One (1) Year
  Delaying the project one (1) year to the next planned unit outage presents multiple risks. These risks include decreased PM removal efficiency and risk of unit outages due to inability to maintain environmental compliance. As bags start to fail, the failure will accelerate exponentially leading to PM compliance issues and potentially multiple unit outages to replace failed filter bags. This alternative is not recommended due to the above risks and unfavorable NPVRR.

  Alternative #2 – Do Nothing
  This alternative is not recommended as this would yield a high probability of forced unit outages and would be unfavorable to unit operations.

Project Description

- **Project Scope and Timeline**

  Ghent Unit 4 work is scheduled to be performed during the spring 2019 outage. At the earliest, the PJFF can be accessed beginning on March 4, 2019. All work, including the leak test and final inspections, is to be complete by March 29, 2019. The below scope items have been competitively bid as a turnkey project; a single bidder will be awarded both the bag purchase and installation services.

  The project scope includes the following:
  - New filter bag fabrication
  - Inspection of pulse air components including pulse air piping, headers, and j-pipes
  - Removal of existing bags and cages
  - Disposal of used bags
  - Installation of new bags and existing cages
  - Replacement of top hatch door gaskets (labor only, not material)
  - Leak test with fluorescent powder to ensure proper installation
  - Optional bag pre-coat if contractor deems hydrated lime is not acceptable

The expected project milestones are as follows:

- o June 2018   RFQ released
- o July 2018   Bids received
- o September 2018   Award contract, place order for new bags
- o January 2019   Delivery of new bags
- o February 2019   Pre-outage mobilization activities
- o March 2019   Outage starts, work begins, work complete

- **Project Cost**

The total project cost is $2,337k, including $212k of contingency. The total cost is based on received bids for labor, material, and equipment. The dollar amount from the highest bidder was used as the basis for the estimated project cost, as a conservative approach since bid evaluation is ongoing. Also included in the cost is funding for top hatch gasket material (provided by KU) and estimated KU labor throughout the duration of the project.

Economic Analysis and Risks

- **Bid Summary**

MBE/WBE	
Removal Labor	
Installation Labor	
Removal Equipment	
Installation Equipment	
Material	
Other Pricing	
Total ($000s)	

███ was the only bidder to include other pricing. This price is a combination of equipment and labor for both removal and installation activities. Specifically, it is the cost of a vacuum truck, labor to handle the equipment, and labor to inspect clean up. This scope was included in the RFQ requirements, and other bidders included the cost in their base offering.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed		1,881			1,881
2. Cost of Removal Proposed		456			456
3. Total Capital and Removal Proposed (1+2)	-	2,337	-	-	2,337
4. Capital Investment 2018 BP			2,076		2,076
5. Cost of Removal 2018 BP			139		139
6. Total Capital and Removal 2018 BP (4+5)	-	-	2,215	-	2,215
7. Capital Investment variance to BP (4-1)	-	(1,881)	2,076	-	195
8. Cost of Removal variance to BP (5-2)	-	(456)	139	-	(317)
9. Total Capital and Removal variance to BP (6-3)	-	(2,337)	2,215	-	(122)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$6
Contract Labor:	$575
Materials:	$1,347
Equipment	$102
Other Pricing:	$70
Burdens:	$25
Contingency:	$212
Reimbursements:	($0)
Net Capital Expenditure:	$2,337

- **Assumptions**

For the recommended project, the following assumptions were made:
   o Capital spend only occurring in 2019
   o All fabric filter bags will be supplied by the contractor
   o 10% contingency on total project cost

For alternative #1, delay the project one (1) year, the following assumptions were made:
   o Capital spend occurring in 2019 and 2020
   o 10% milestone payment on the fabric filter bags in 2019 based off the material cost
   o 2% inflation rate
   o 25% probability of a four (4) day forced outage due to replacing failed bags

o   Incremental costs include labor and material for replacing bags in two (2) through compartments if a failure occurred; labor rates from the highest bidder were used as well as assuming the bags will be checked out of Ghent's warehouse at the current burden rate of 20%

For alternative #2, do nothing, the following assumptions were made:
o   25% probability of a four (4) day forced outage starting in 2019 and increasing by 25% each year; the probability would be 100% by 2022
o   Incremental costs for 2019-2022 are the same as alternative #1, including 2% inflation each year
o   100% probability of a one (1) week forced outage starting in 2023 and occurring indefinitely
o   Incremental costs for 2023 and beyond include labor and material for replacing bags in four (4) total compartments, including 2% inflation each year

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	Yes
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	No
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

The Ghent Environmental Supervisor has reviewed and approved this project.

- **Risks**

Failure to meet particulate emissions limit: If the filter bags are not replaced there is a risk that particulate emissions will increase and pose a risk to the unit's reliability.

Forced outages: If the bags are not replaced there is a risk that the particulate emissions will not meet compliance regulations and the unit will be forced to take outages to replace sections of broken bags.

Changing bags online: The bags could be changed one compartment at a time while the Unit remains online, however, the life expectancy of the new bags would be greatly affected due to gas flow taking the path of least resistance through the new, clean bags. Also, changing the bags online constitutes a higher risk in safety.

Limited timeline: The timeline for this project is limited due to material lead time. There is a risk that if an order for the material is not submitted in the 3rd quarter of 2018, the filter bags may not be delivered in time for the spring outage. This could result in an extended outage or a one (1) year delay in the project.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the GH4 PJFF Bag Replacement project for $2,337k to continue to meet particulate matter emission limits and avoid forced unit outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:
Kent Blake
C055E669F1EB443...
Kent W. Blake   Date
Chief Financial Officer

DocuSigned by:
Paul Thompson
57E11AF682314EE...
Paul W. Thompson   Date
Chairman, CEO and President

Arbough

Investment Proposal for Investment Committee Meeting on: October 31, 2018

Project Name: GH4 Primary SH Repl

Total Expenditures: $3,826k   (Including $217k of contingency)

Project Number(s): 137474

Business Unit/Line of Business: <u>Ghent Generating Station / Power Generation</u>

Prepared/Presented By: <u>Stephen Nix / Steve Turner</u>

Executive Summary

This project is for replacement of the Primary Superheater in the furnace backpass of Ghent Unit 4. A similar project is being completed on Ghent Unit 3 during the fall 2018 outage as the result of numerous tube failures. The scope of this project includes the design and supply of new assemblies with installation during the spring 2020 outage. This boiler section is planned to be replaced simultaneously with both the Upper Economizer Upper Bank (Project 137244) which is situated directly below in the same boiler gas backpass and the Vertical Reheater (Project 155017) which is situated directly above. Materials for all three projects will be designed and fabricated by the same supplier with installation by the same contractor. The Unit 4 Primary Superheater is original to the unit. There are design issues with tube support connections (solid ties) which have caused numerous leaks over the past two decades. This condition will continue to get worse with age of the assemblies. As Unit 3 is three years older than Unit 4, the degraded condition and failures were first seen on that unit. Proactive maintenance has helped mitigate tube leaks on Unit 4 to this point, but as wear continues deeper in the tube banks, failures are anticipated to mirror that of Unit 3. This project is being recommended in accordance with the Ghent Boiler Reliability Plan.

Tubing material supply for this project and the two other large boiler projects mentioned above is being sole sourced to ▮▮▮▮▮▮ using the aggregated competitive bid strategy performed for Unit 3 as the basis. This approach is providing cost savings on engineering and will maintain the same design that was provided for the identical project scope on Ghent Unit 3. The contract for erection is being competitively bid and awarded under the Boiler Craft Labor 2019-2020 contract initiative.

This project was first submitted in the 2013 BP, is approved for $4,243k in the 2018BP, and was proposed for $4,169k in the 2019BP. Although labor bids are still being negotiated, preliminary bid information was utilized to develop the installation cost. In the 2018 8+4 forecast, the Resource Allocation Committee (RAC) approved $312k to be spent in 2018. These funds will be pulled forward from 2019 and will allow for initial milestone payments on materials. The funds for this project in the 2018 RAC approved forecast and 2019BP which are in excess of the

requested amount will be used in part to offset funding needs for other Ghent boiler projects. Although associated with this outage.

Background

The Unit 4 Primary Superheater has been in service since startup in 1984. The Primary Superheater is constructed mostly of low alloy carbon steel tubing. Normal operating conditions and years of service in the superheat front backpass have caused tube leaks due to flyash erosion and failures with the tube assembly alignment system. Alignment system failures and related support lug disengagements will lead to fatigue cracking at solid tube ties. More than thirty leaks have occurred on the identical Foster Wheeler assemblies in Unit 3. There have been three leaks in these assemblies on Unit 4 in the last 5 years.

The goal of this project is to replace the Primary Superheater and to use the improved design being installed on Unit 3 for better alignment and support. The improved design will keep tubes aligned and support lugs engaged. Solid tube ties will be eliminated. Tube shields will be installed to protect from flyash and sootblower erosion. The result of these improvements will be fewer forced outages from tube failures. Also, a reduction in the number of different material grades and wall thickness in the primary superheater will save on fabrication costs and plant tube inventory.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $4,055
     Execute this project by replacing the Primary Superheater in 2020.

  2. Delay project to 2027 (next major outage)   NPVRR: ($000s) $5,990
     Forced outages to be expected until implemented. Manage the risk of forced outages with more inspections, tube shielding, dutchmen, pad welding and repairs. Mobilization and unit access costs will be higher for this project and for the Upper Economizer Upper Bank replacement (Project 137244) if not performed during the same outage.

  3. Do nothing. Repair leaks on O&M   NPVRR: ($000s) $9,134
     Continue operation and maintenance without replacement. Forced outages have a high probability to increase. Manage the risk of forced outages with more inspections, tube shielding, dutchmen, pad welding and repairs.

The project cost evaluation shows it is more beneficial to replace the Primary Superheater in 2020 than it is to either delay replacement until the next major outage in 2027 or to Do Nothing and continue operation and maintenance without replacement while risking forced outage leak repairs.

Project Description

- **Project Scope and Timeline**

The Primary Superheater replacement will take place during the spring 2020 outage. The Arbough installation work was included in the Boiler Craft Labor 2019-2020 contract initiative. Installation bids were solicited from multiple contractors in July 2018 and are being evaluated. Tubing material supply for this project is being sole sourced using the January 2017 Unit 3 competitive bid as a basis. Those bids for materials were solicited from seven boiler pressure part suppliers. This strategy will maintain a consistent design between Units 3 and 4 as well as offering savings on engineering costs.

The goal for the new Unit 3 design was to resolve operational and maintenance issues with the existing assemblies. Additional alignment straps made of temperature resistant Inconel material will be added to enable the elimination of solid ties in favor of tube saddles. Tube shields will be added in the sootblowing lanes. Tube cut points have been selected to facilitate erection. Tube material changes are being reduced so there will be fewer shop welds.

Milestones:
- October 2018 – Investment Committee meeting and approval
- November 2018 – Issue material purchase order
- February 2020 – Material received
- March 2020 – Outage Start
- May 2020 – Complete Outage work

- **Project Cost**

  Total cost of the 2020 project is estimated to be $3,826k.

  There is a 5% contingency for material and a 7% contingency for installation. Contingency considerations are included during the execution of the material contract in 2019 and 2020 and for installation during the outage in 2020.

Economic Analysis and Risks

- **Bid Summary**

Bid Summary (Installation): Bids for these projects were received under the Boiler Craft Labor 2019-2020 contract initiative and are being reviewed. Although labor bids are still being negotiated, preliminary bid information was utilized to develop the installation cost. A labor contract will be presented to the Investment Committee at a later date.

Bid Summary (Material Supply): Material for this project is proposed to be sole sourced to ▮▮ ▮▮▮▮ for $1,413k. Nearly the same scope of supply was competitively bid for Ghent Unit 3 along with two other large boiler projects in 2017. ▮▮▮▮▮▮ was the successful bidder. Utilizing ▮▮▮▮▮▮ reduces engineering costs and maintains the same component design on Ghent 3 and 4.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	261	901	1,931		3,093
2. Cost of Removal Proposed			733		733
3. Total Capital and Removal Proposed (1+2)	261	901	2,664	-	3,826
4. Capital Investment 2018 BP		633	3,192		3,825
5. Cost of Removal 2018 BP			418		418
6. Total Capital and Removal 2018 BP (4+5)	-	633	3,610	-	4,243
7. Capital Investment variance to BP (4-1)	(261)	(268)	1,261	-	732
8. Cost of Removal variance to BP (5-2)	-	-	(315)	-	(315)
9. Total Capital and Removal variance to BP (6-3)	(261)	(268)	946	-	417

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$22
Contract Labor:	$1,865
Materials:	$1,426
Local Engineering:	$0
Burdens:	$296
Contingency:	$217
Reimbursements:	($0)
Net Capital Expenditure:	$3,826

- **Assumptions**

The Capital Evaluation Model contains the following assumptions:
- o 5% contingency on boiler tube material supply and 7% contingency on installation plus burdens have been included in capital investment costs.
- o Availability Disimprovement (AD) for Unit 4 was calculated based on Unit 3 forced outage data. Unit 3 has been in service three years longer. Failures will likely parallel Unit 3 and be in eroded areas deeper in the tube bank which are inaccessible to boiler inspectors.
- o Availability Disimprovement (AD) probability is based on three forced outages per year and progressively becoming more frequent. Forced outages last 1.5 days each. AD probability is based on historical leaks with age factored.

- o Incremental cost is based on $19k to fix leaks, $130k unit startup cost and $50k **Arbough** preventive maintenance (PM) on assemblies per year. After project implementation, annual PM costs are zero. PM costs increase with age. Forced outage maintenance and startup costs are factored based on the AD probability above.
- o 3% inflation assumed per year for Incremental Costs and delayed Capital Investment project.
- o Alternative #1 is to delay the project 7 years to the next major outage in 2027.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	Yes
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	Yes
	a. Provide frequency or when equipment or component in question was last repaired or replaced.	Annual
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment?	Yes
	a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	

8a. GADS data shows leaks on 10/14/2013, 5/3/2017 and 7/15/2017.

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**

Choosing one of the alternatives such as not implementing the tube replacement project or delaying the work until the next major outage will lead to forced outages and will have a negative commercial impact.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the GH4 Primary SH Repl project for $3,826k to avoid forced outages and to maintain the reliability of Ghent Unit 4.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by: *Kent Blake*	11/2/2018 | 8:42 AM EDT	DocuSigned by: *Paul Thompson*	11/8/2018 | 6:27 AM EST
Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Arbough

Investment Proposal for Investment Committee Meeting on: October 31, 2018

Project Name: GH4 Upper Econ Repl

Total Expenditures: $2,783k   (Including $175k of contingency)

Project Number(s): 137244

Business Unit/Line of Business: <u>Ghent Generating Station / Power Generation</u>

Prepared/Presented By: <u>Stephen Nix / Steve Turner</u>

Executive Summary

This project is for replacement of the Upper Economizer Upper Bank in the furnace backpass of Ghent Unit 4. A similar project is being completed on Ghent Unit 3 during the fall 2018 outage as the result of numerous tube failures. The scope of this project includes the design and supply of new assemblies with installation during the spring 2020 outage. This boiler section is planned to be replaced simultaneously with both the Primary Superheater (Project 137474) which is situated above in the same boiler gas backpass and the Vertical Reheater (Project 155017) which is situated directly above the Primary Superheater. Materials for all three projects will be designed and fabricated by the same supplier with installation by the same contractor. The Unit 4 Upper Economizer Upper Bank is original tubing to the unit. There are design issues related to tube support disengagement and areas subject to fly ash and sootblower erosion. These conditions will continue to get worse with age of the assemblies. As Unit 3 is three years older than Unit 4, the degraded condition and failures were first seen on that unit. Proactive maintenance has helped mitigate tube leaks on Unit 4 to this point, but as wear develops out of reach of boiler inspectors deeper in the tube banks, failures are anticipated to mirror that of Unit 3. This project is being recommended in accordance with the Ghent Boiler Reliability Plan.

Tubing material supply for this project and the two other large boiler projects mentioned above is being sole sourced to ▇▇▇▇▇ using the aggregated competitive bid strategy performed for Unit 3 as the basis. This approach is providing cost savings on engineering and will maintain the same design that was provided for the identical project scope on Ghent Unit 3. The contract for erection is being competitively bid and awarded under the Boiler Craft Labor 2019-2020 contract initiative.

This project was first submitted in the 2013 BP, is approved for $1,816k in the 2018BP, and $1,707k was proposed in the 2019BP. The increased cost is due to increased material costs and higher than expected installation labor costs. Although labor bids are still being negotiated, preliminary bid information was utilized to develop the installation cost. In the 2018 8+4 forecast, the Resource Allocation Committee (RAC) approved $162k to be spent in 2018. These funds will be pulled forward from 2019 and will allow for initial milestone payments on

materials. The incremental costs in each year of spend on this project will be funded internally through within the Ghent Capital Budget.

Background

The Unit 4 Upper Economizer Upper Bank has been in service since startup in 1984. The Upper Economizer Upper Bank is constructed from carbon steel tubing. Operating conditions in the backpass have caused tube leaks due to flyash and sootblower erosion. Misalignment and support lug disengagement also increases stress in the assemblies. Erosion caused a tube leak in 2016.

This bank of tubing will be replaced before forced outages begin to happen regularly as they did on the identical Foster Wheeler assemblies on Unit 3 where erosion has caused four leaks from 2011 to 2015. Since 2012, forty-six dutchmen tube sections have been installed across thirty-three assemblies during scheduled outages. Many tubes replaced during the scheduled outages were below 50% minimum wall thickness. The actions taken between 2012-2015 were critical in keeping this component from becoming a major EFOR contributor.

The goal of this project is to replace the Upper Economizer Upper Bank with a combination of thicker tube, weld overlay and tube shields in targeted high risk areas. The improved design will provide better resistance to erosion and reduced maintenance in the long term. Tube shields will be located in sootblower lanes to protect from erosion. The result of these improvements will be fewer forced outages from tube failures.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,937
     Execute this project by replacing the Upper Economizer Upper Bank in 2020.

  2. Delay project to 2027 (next major)   NPVRR: ($000s) $4,822
     Forced outages to be expected until implemented. Manage the risk of forced outages with more inspections, tube shielding, dutchmen, pad welding and repairs. Mobilization and unit access costs will be higher for this project and for the Primary Superheater replacement (Project 137474) if not performed during the same outage.

  3. Do nothing. Repair leaks on O&M   NPVRR: ($000s) $8,257
     Continue operation and maintenance without replacement.
     Forced outages have a high probability to increase. Manage the risk of forced outages with more inspections, tube shielding, dutchmen, pad welding and repairs.

The project cost evaluation shows it is more beneficial to replace the Upper Economizer Upper Bank in 2020 than it is to either delay replacement until the next major outage in 2027 or to Do Nothing and continue operation and maintenance without replacement while risking forced outage leak repairs.

Project Description

- **Project Scope and Timeline**

The Upper Economizer Upper Bank replacement will take place during the spring 2020 outage. The installation work was included in the Boiler Craft Labor 2019-2020 contract initiative. Installation bids were solicited from multiple contractors in July 2018 and are being evaluated. Tubing material supply for this project is being sole sourced using the January 2017 Unit 3 competitive bid as a basis. Those bids for materials were solicited from seven boiler pressure part suppliers. This strategy will maintain a consistent design between Units 3 and 4 as well as offering savings on engineering costs.

The goal for Unit 4 assemblies is to use the same design as on Unit 3. This design will resolve operational and maintenance issues with the existing assemblies. An improved design with a combination of thicker tube, weld overlay and tube shields on bends and fully shielded end assemblies has been specified. Tube cut points have been selected to facilitate erection. Tube shields will be added in the sootblowing lanes. Tube material changes are being reduced so there will be fewer shop welds.

Milestones:
- October 2018 – Investment Committee meeting and approval
- November 2018 – Issue material purchase order
- February 2020 – Material received
- March 2020 – Outage Start
- May 2020 – Complete Outage work

- **Project Cost**

Total cost of the 2020 project is estimated to be $2,783k.

There is a 5% contingency for material and an 8% contingency for installation. Contingency considerations are included during the execution of the material contract in 2019 and 2020 and for installation during the outage in 2020.

Economic Analysis and Risks

- **Bid Summary**

Bid Summary (Installation): Bids for these projects were received under the Boiler Craft Labor 2019-2020 contract initiative and are being reviewed. Although labor bids are still being negotiated, preliminary bid information was utilized to develop the installation cost. A labor contract will be presented to the Investment Committee at a later date.

Bid Summary (Material Supply): Material for this project is proposed to be sole sourced to ▉▉ ▉▉▉▉ for $884k. Nearly the same scope of supply was competitively bid for Ghent Unit 3 along with two other large boiler projects in 2017. ▉▉▉▉▉▉ was the successful bidder. Utilizing ▉▉▉▉▉▉ reduces engineering costs and maintains the same component design on Ghent 3 and 4.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	163	567	1,453		2,183
2. Cost of Removal Proposed			600		600
3. Total Capital and Removal Proposed (1+2)	163	567	2,052	-	2,783
4. Capital Investment 2018 BP		573	1,087		1,660
5. Cost of Removal 2018 BP			155		155
6. Total Capital and Removal 2018 BP (4+5)	-	573	1,243	-	1,816
7. Capital Investment variance to BP (4-1)	(163)	6	(365)	-	(523)
8. Cost of Removal variance to BP (5-2)	-	-	(444)	-	(444)
9. Total Capital and Removal variance to BP (6-3)	(163)	6	(810)	-	(967)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$15
Contract Labor:	$1,502
Materials:	$895
Local Engineering:	$0
Burdens:	$196
Contingency:	$175
Reimbursements:	($0)
Net Capital Expenditure:	$2,783

- **Assumptions**

The Capital Evaluation Model contains the following assumptions:
  - 5% contingency on boiler tube material supply and 8% contingency on installation plus burdens have been included in capital investment costs.
  - Availability Disimprovement (AD) for Unit 4 was calculated based on Unit 3 forced outage data. Unit 3 has been in service 3 years longer. Failures will likely parallel Unit 3 and be in eroded areas deeper in the tube bank which are inaccessible to boiler inspectors.
  - Availability Disimprovement (AD) probability is based on three forced outages per year and progressively becoming more frequent. Forced outages last 1.5 days each. AD probability is based on historical leaks with age factored.
  - Incremental cost is based on $19k to fix leaks, $130k unit startup cost and $50k preventive maintenance (PM) on assemblies per year. After project implementation

annual PM costs are zero. PM costs increase with age. Forced outage maintenance though Arbrough startup costs are factored based on the AD probability above.

o 3% inflation assumed per year for Incremental Costs and delayed Capital Investment project.

o Alternative #1 is to delay the project 7 years to the next major outage in 2027.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	Yes
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	Yes
	a. Provide frequency or when equipment or component in question was last repaired or replaced.	Annual
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment?	Yes
	a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	

8a. GADS data shows leaks 3/14/16.

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**

Choosing one of the alternatives such as not implementing the tube replacement project or delaying the work until the next major outage will lead to forced outages and will have a negative commercial impact.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the GH4 Upper Econ Repl project for $2,783k to avoid forced outages and to maintain the reliability of Ghent Unit 4.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent Blake	11/2/2018 | 8:42 AM EDT	*Paul Thompson*	11/8/2018 | 6:27 AM EST
Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: October 31, 2018

Project Name: GH4 Vertical RH Partial Repl

Total Expenditures: $4,041k   (Including $244k of contingency)

Project Number(s): 155017

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Ben Zeigler/Steve Turner

Executive Summary

This project scope includes the purchase and installation of twenty-nine vertical reheater tube assemblies for the Ghent Unit 4 boiler. A similar project was completed on Ghent Unit 3 during the fall 2018 outage as the result of several tube failures driven by corrosive attack from various fuel constituents, primarily chlorine. Inspection data shows that tube failures on Ghent 4 are expected if repairs are not made. The scope of this project includes the front and rear portions of the vertical reheater and includes all support loops that extend into the penthouse. All assemblies will be fabricated with 304H stainless steel tube material to combat the advanced corrosion. This design will mirror existing elements in this area that are not showing signs of degradation. This change in material selection will not alter the geometry and will have no effect on the overall boiler heat input or combustion process. This boiler section is planned to be replaced simultaneously with both the Upper Economizer Upper Bank (Project 137244) and the Primary Superheater (Project 137474) which are situated directly below the front vertical reheat.

This component was replaced in 2002 with additional surface area as an attempt to balance steam temperatures at the time of a selective catalytic reduction equipment addition, burner replacement, and waterwall refractory removal. After discovering advanced corrosion occurring in this same component on Ghent 3, increased inspection efforts and localized repairs were made to extend the life of the component until a larger scale project could be planned. In order to mitigate future risk of tube failures in this component, it is recommended to replace twenty-nine assemblies during the spring 2020 outage. This project is being recommended in accordance with the Ghent Boiler Reliability Plan.

Tubing material supply for this project and the two other large boiler projects mentioned above is being sole sourced to ▓▓▓▓▓▓ using the aggregated competitive bid strategy performed for Unit 3 as the basis. This approach is providing cost savings on engineering and will maintain the same design that was provided for the identical project scope on Ghent Unit 3. The contract for erection is being competitively bid and awarded under the Boiler Craft Labor 2019-2020 contract initiative.

A total of $5,116k was included in the 2018BP and $5,104k is included in the proposed 2019BP. Although This project is currently estimated to cost $4,041k. Although labor bids are still being negotiated, preliminary bid information was utilized to develop the installation cost. The funds for this project in the 2019BP which are in excess of the requested amount will be used in part to offset funding needs for other Ghent boiler projects associated with this outage. In the 2018 8+4 forecast, the Resource Allocation Committee (RAC) approved $126k to be spent in 2018. These funds will be pulled forward from 2019 and will allow for initial milestone payments on materials. Incremental costs in 2018 and 2019 over the BP amount will be funded within the Ghent Capital Budget.

Background

When this component was replaced in 2002, twenty-four of sixty-three assemblies were made of stainless steel material. These were strategically placed in two separate zones of the boiler that were known to operate at higher temperatures. The other thirty-nine assemblies were made of low alloy carbon steel tubing. The areas just outside of these stainless zones are now experiencing coal ash corrosion due to high tube temperatures and elevated chlorine content in fuel. The project scope includes twenty-nine new stainless assemblies, leaving ten alloy assemblies in the center of the unit. These are known to operate with cooler tube metal temperatures and current material condition does not warrant replacement. The project scope does include the replacement of the single most damaged circuit in these ten assemblies that will remain.

This project is necessary to address the worst areas of corrosion attack. The existing tubing material is SA-213 T22 and has a chromium (Cr) content of 2.25%. The new assemblies will be fabricated with SA-213 TP304H, which contains up to 20% Cr that will better withstand the operating environment. Extensive inspections and repairs have been made to address this issue. During the spring 2017 outage, seven individual tubes were replaced to address immediate reliability risk. The same damage mechanism was found on Ghent Unit 3 and has caused three tube failures. While there has not yet been any tube failures on Ghent Unit 4 due to this issue, this project is necessary to prevent them. Upgrading the tube material to stainless in this area will deliver long term protection against high tube temperatures and coal ash corrosion.

- **Alternatives Considered**
    1. Recommended replacement of 29 assemblies   NPVRR: ($000s) $4,466

    2. Defer project 7 years to 2027   NPVRR: ($000s) $6,094

    3. Do nothing. Repair leaks on O&M   NPVRR: ($000s) $6,178

The recommended option is to replace twenty-nine assemblies during the spring 2020 outage. Alternatively, deferring the project seven years to 2027 was also considered. The observed material condition of the tubing provides confidence that the tubing will not last until 2027 without a significant EFOR impact. The risk of tube failures and continued O&M spend will increase substantially if no major replacement is made.

Project Description   **Arbough**

- **Project Scope and Timeline**
  The scope of this project includes a material upgrade to combat high tube temperatures and coal ash corrosion.
  - October 2018   IC meeting and approval
  - November 2018   Issue purchase order for material
  - February 2020   Material delivered to Ghent for 2020 install
  - March 2020   Outage start
  - May 2020   Complete outage work

- **Project Cost**
  Total cost of the 2020 project is estimated to be $4,041k.

  There is a 5% contingency for material and an 8% contingency for labor. Contingency considerations are for additional boiler inspection findings and rigging complication.

Economic Analysis and Risks

- **Bid Summary**

Bid Summary (Installation): Bids for these projects were received under the Boiler Craft Labor 2019-2020 contract initiative and are being reviewed. Although labor bids are still being negotiated, preliminary bid information was utilized to develop the installation cost. A labor contract will be presented to the Investment Committee at a later date.

Bid Summary (Material Supply): Material for this project is proposed to be sole-sourced to ▮▮ ▮▮▮ for $1,196k. The same scope of supply was competitively bid for Ghent Unit 3 along with two other large boiler projects in 2017. ▮▮▮▮▮ was the successful bidder. Utilizing ▮▮▮▮ reduces engineering costs and maintains the same component design on Ghent 3 and 4.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	221	618	2,236		3,075
2. Cost of Removal Proposed			966		966
3. Total Capital and Removal Proposed (1+2)	221	618	3,202	-	4,041
4. Capital Investment 2018 BP		406	4,164		4,570
5. Cost of Removal 2018 BP			546		546
6. Total Capital and Removal 2018 BP (4+5)	-	406	4,710	-	5,116
7. Capital Investment variance to BP (4-1)	(221)	(212)	1,928	-	1,495
8. Cost of Removal variance to BP (5-2)	-	-	(420)	-	(420)
9. Total Capital and Removal variance to BP (6-3)	(221)	(212)	1,508	-	1,075

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$40
Contract Labor:	$2,249
Materials:	$1,219
Local Engineering:	$0
Burdens:	$289
Contingency:	$244
Reimbursements:	($0)
Net Capital Expenditure:	$4,041

- **Assumptions**
  - Discount rate of 6.59% was obtained from the current CEM model
  - Availability "disimprovement" was determined to be two three day (0.43 weeks) outages caused by boiler tube failures. An incremental increase in probability is assumed.
  - Deferring the project to 2027 (alternative #2) assumes a 3% inflation rate. Spending is included in 2025 and 2026 for material procurement.
  - Incremental costs are based on, $130k for unit start up, and $28k for tube failure repair. These costs are multiplied by the probability of disimprovement.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes 2002
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment?	No

	a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	**Arbough**

The Ghent Environmental Supervisor and Environmental Affairs has reviewed and approved this project.

- **Risks**
  - The most significant risks to this project are related to the project schedule. The location of these boiler components require complex rigging and difficult welds to be made.
  - If this project is delayed a significant EFOR impact will be realized.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the GH4 Vertical RH Partial Repl project for $4,041k to avoid future forced outages and to maintain the reliability of Ghent Unit 4.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:

Kent Blake   11/2/2018 | 8:42 AM EDT

C055E669F1EB443...

Kent W. Blake   Date

Chief Financial Officer

DocuSigned by:

Paul Thompson   11/8/2018 | 6:27 AM EST

57E11AF682314EE...

Paul W. Thompson   Date

Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: Ghent 138kv Switchyard Reconfiguration

Total Expenditures: $4,647k (Including $371k of Contingency)

Project Number(s): Substation Construction – 131355, P&C – 150644

Business Unit/Line of Business: Generation

Prepared/Presented By: Ritchie Chambless – Project Manager, Generation
                       Chris Talley – Manager, Transmission Substation Construction

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Executive Summary

Generation and Transmission recommend reconfiguring the Ghent 138kv switchyard as described below to eliminate a single point of failure for the Ghent Unit 1 generator, improve the ability to perform switchyard maintenance and improve switchyard reliability.

- Install tie-breaker between 716 & 754 breakers for connecting Unit 1 generator to either the south bus or north bus.
- Install tie-breaker between 724 & 764 breakers and separate the existing common bus and protection system so it can be operated as a two bus system.
- Install protection relaying for normal breaker and a half operation as in our 345kv switchyard.
- Disconnect the T-389 345kv/138kv tie transformer from the south bus and reconnect to the north bus.

The 2011 Fleet Single Point of Failure Analysis identified a single point of failure in the Ghent 138kv switchyard for GH1 generator. The GH1 generator is connected to the north 138kv bus through a single circuit breaker and an isolation disconnect switch. A breaker failure, disconnect switch failure or a 138kv bus outage will force Unit 1 generator off line.

The project estimated cost is $4,647k, with $624k in 2016, $3,694k in 2017 and $329k in 2018. This project was included in Power Generation's 2016 BP (project 137024). Since the project involves Transmission assets, the BP was moved from Power Generation to Transmission in the 2017 BP. Transmission's 2017 BP for the project is $4,210k with $599k in 2016, $3,101 in 2017 and $510k in 2018.

The cost estimate was revised after the BP submittal based on further development of the scope as part of the engineering effort. The increased cost ($437k) between the 2017 BP and the estimated cost is primarily due to the need to expand the control building.The 2016 spending was approved by the RAC in the 10+2 forecast to complete the design to obtain firm pricing. The 2017 variance will be addressed through the allocation of funds through the RAC during 2017.

The 138kv switchyard is comprised of a north bus and a south bus that are operated as one common bus via a normally closed tie switch. The following issues arise when a bus fault occurs with our existing common bus configuration. Transmission loses network connectivity of the 138kv lines leaving the switchyard. Ghent Station loses GH1 and GH3 25kv reserve power system, one of the Coal Combustion Residual (CCR) power sources, one ammonia farm power source and one limestone prep power source. As a result GH1 is forced into an uncontrolled shutdown which presents severe risks to the boiler and potential catastrophic damage to the turbine-generator. Separating the two buses and providing separate protection for each bus will insure one bus will be in operation when there is a fault on the other bus. The existing 138kV switchyard configuration as well as the recommended single line is shown in Appendix 1.

The 138kv switchyard is connected to the Ghent 345kv system through two different 345kv/138kv autotransformers. Both autotransformers are connected to the south 138kv bus. GH1 generator is connected to the north 138kv bus. An outage on the south bus will force a load limit on GH1 generator because the capability of GH1 generator is greater than the two 138kv transmission lines connected to the north bus.

Background
The existing Ghent 138kv switchyard was designed and built over 40 years ago and does not provide the level of redundancy and reliability required by today's operating standards. The 2011 Fleet Single Point of Failure Analysis identified a single point of failure in the Ghent 138kv switchyard for GH1 generator. Failure of the 716 breaker or a 138kv bus fault forces a GH1 generator outage.

When GH1 and the GH1/GH3 25kv reserve system trip during a 138kv bus fault, GH1 comes off line uncontrolled, meaning without auxiliary power to the unit. Consequently, the unit must rely on emergency backup systems to ensure proper cooling and lubrication via DC pumps and battery backup. The intent of these systems are to protect the unit in the most extreme circumstances such as a major transmission failure, not a bus fault. Additionally, without auxiliary power, major systems such as the boiler feed pumps will trip without backup, resulting in a dry boiler and related overheating issues and extended startup time waiting for drum metal temperatures to stabilize. An emergency quench system will initiate to protect the scrubber mist eliminators. The baghouse will go into bypass to prevent overheating and catching fire. DC motors will put the turbine on turning gear to prevent bowing of the rotor. DC lube oil and seal oil pumps will come on to protect the turbine generator bearings and ensure generator seals continue to contain hydrogen. Failure of the UPS system and any of these systems can result in extended outage times and major financial impact. An uncontrolled unit shutdown presents severe risks to the boiler and potential catastrophic damage to the turbine-generator. The estimated cost to rebuild a turbine-generator set after a catastrophic failure is $135M in 2016 dollars with the unit offline 24 to 36 months. There have been similar units in the industry retired after a catastrophic failure.

An uncontrolled unit shutdown with loss of auxiliary power also causes the limestone and Arbough gypsum sumps to overflow potentially resulting in limestone and gypsum slurry releases into the Ohio River through storm drains.

A 138kv bus fault also trips the GH3 25kv reserve system which prevents a GH3 controlled shutdown or start-up if required at the time of the bus fault.

In addition to addressing operational concerns at the plant, this proposed project presents the following benefits to Transmission:
- An outage to the bus in the existing configuration results in the loss of (2) 450 MVA, 345/138kV transformers as well as (6) 138kV lines on a radial feed from the remote end.   Upon completion of this project, a bus outage will lead to the loss of a 345/138kV transformer and a single 138kV line on a radial feed.
- Outages to complete routine maintenance of equipment will be less problematic due to operational flexibility offered by reconfiguring the switchyard.
- Protection schemes will be upgraded from electromechanical schemes to microprocessor based relays. This will also include establishing a redundant protection scheme for both the bus and lines.

Listed below are incidents on record that have caused forced outage time on GH1 generator. A 138kv bus outage also occurred during the 11/13/15 and 6/14/07 incidents.
- 11-18-2015 – 5.73 hours of GH1 forced outage. Disconnect switch 703 failed which forced Unit 1 off line at 2124 hours. The disconnect switch was repaired and Unit 1 was placed back on line 11-19-2015 at 0308 hours.
- 11-13-2015 – 54.25 hours of GH1 forced outage. Disconnect switch 716B failed which caused 716 breaker to fail. GH1 tripped at 2223 hours. The disconnect switch and breaker were replaced and GH1 was placed back on line 11-16-2015 at 0438 hours.
- 6-14-2007 – 10.42 hours of GH1 forced outage. North bus 'C' phase potential transformer faulted to ground at 0637 causing a 138kv bus lockout which tripped GH1. The potential transformer failure was isolated and GH1 was placed back on line at 1702 the same day.

Listed below are other incidents Mr. David Payne, retired KU Manager of Transmission Substation and Protection, remembers that have caused forced outages on GH1 generator and the Ghent 138kv switchyard bus during the early years of operation.
- GH1 generator had to be taken off line due to overheating disconnects on breaker 716.
- GH1 generator could not be put on line because of a mechanism failure on breaker 716.
- A bus fault occurred when an oil circuit breaker on the south bus had an internal failure attempting to reclose into a transmission line fault.
- A bus fault occurred when a lineman caused a conductor to fall across the south bus during GH2 construction.
- A bus fault occurred when a transmission line conductor fell across the south bus due to a mechanical failure.
- A bus fault occurred due to a tornado related event.

Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)   Arbough
  Alternative 1 - Recommendation – NPVRR: ($000s) $5,202k
    These reconfiguration changes to the 138kv switchyard are recommended and will eliminate a single point of failure for the GH1 generator, minimize Ghent 138kv switchyard forced outages, minimize uncontrolled Unit 1 shutdowns and improve the ability to perform switchyard maintenance.

  Alternative 2 - Do Nothing – NPVRR: ($000s) $147,103k
    We will continue to have a single point of failure for Unit 1, severe risks to the boiler and potential catastrophic damage to the turbine-generator. The cost of this alternative assumes that a switchyard 138kv bus fault occurs in 2017 which then causes the Turbine Generator (T-G) back-up DC lube oil pump system to fail as a result. The resulting implications assumed in this alternative are described in the Assumptions section. The NPVRR for this alternative was calculated using a separate CEM for the Power Generation line of business and the Steam Production depreciation category since the T-G and related costs are not transmission assets.

  Alternative 3 - Next Best Alternative – NPVRR: ($000s) $5,986k
    Complete all work noted in the recommended alternative along with the addition of a breaker between the Fairview and Gallatin lines making the station layout a true breaker and a half configuration from a Transmission perspective.

Project Description

- **Project Scope and Timeline**
  The scope of this project involves separating the existing 138kV bus into two separate sections and moving one of the 345/138kV transformers from the north bus to the south bus. This includes the addition of the following equipment:
    - (2) 138kV breakers
    - (5) 138kV disconnect switches
    - Miscellaneous equipment such as instrument transformers and bus work.

  The Protection and Control scheme will be revised as follows:
    - Control Building:
      The control building will be expanded to contain the new redundant protection relay panels.
    - Relay Panels:
      All electromechanical relays will be replaced with microprocessor relays for all transmission assets. This includes the removal of (8) electromechanical panels and the installation of (11) microprocessor protection panels. Currently, only the 165-714 line protection panel provides redundancy. After the completion of the project, all line and bus protection will be redundant. In addition, breaker failure will be implemented on all breakers.
    - Cable:

Install 92,100 feet of various cables between Panel to panel, panel to substation Arbough equipment, and panel to generation plant. Cables will be installed to incorporate redundancy with trip coils and CT circuits where applicable.

- Batteries:
Existing batteries are under sized for proposed substation layout and additional required equipment. The DC systems (battery banks, charges and DC panels) will be replaced to sufficiently provide required amp-hour ratings and DC circuit isolation.

Description	Date
Preliminary Engineering Project Approval	April, 2016
Physical Engineering Completed	October, 2016
Full Project Approval	December, 2016
Protection and Control Work Begins	February, 2017
Subs Construction Below Grade Work Begins	April, 2017
Protection and Control Engineering Completed	June, 2017
Subs Construction Below Grade Work Completed	July, 2017
Subs Construction Above Grade Work Begins	September, 2017
Subs Construction Above Grade Work Completed	December, 2017
Protection and Control Work Completed	March, 2018
Unit Outage Work	March, 2018
Project Complete	April, 2018

- **Project Cost**
The project estimated cost is $4,647k, with $624k in 2016, $3,694k in 2017 and $329k in 2018. The estimate includes an 8% contingency. This contingency is reasonable based on the level of detailed engineering performed in 2016 and is expected to cover uncertainty with the contract labor costs based upon variances that have been observed on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
Physical Work:
Bids for the below grade and above grade work have been received and evaluated. The bid prices were used as part of the cost estimate reflected in this Investment Proposal. Material prices for major components are firm while estimated costs were used for minor material.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	624	3,694	329	-	4,647
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	624	3,694	329	-	4,647
4. Capital Investment 2017 BP	599	3,101	510	-	4,210
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	599	3,101	510	-	4,210
7. Capital Investment variance to BP (4-1)	(25)	(592)	181	-	(437)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(25)	(592)	181	-	(437)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Spend (000's)	2016	2017	2018	Total	Arbough
Company Labor					
Subs Const	$ 15	$ 60	$ 10	$ 85	
P&C	$ 38	$ 208	$ 119	$ 365	
Contract Labor					
Subs Const	$ 192	$ 590	$ 15	$ 797	
P&C	$ 280	$ 652	$ 55	$ 987	
Materials					
Subs Const	$ -	$ 600	$ -	$ 600	
P&C	$ -	$ 778	$ -	$ 778	
Burdens					
Subs Const	$ 37	$ 160	$ 9	$ 206	
P&C	$ 62	$ 299	$ 97	$ 458	
Contingency					
Subs Const	$ -	$ 142	$ 4	$ 146	
P&C	$ -	$ 205	$ 20	$ 225	
Total					
Subs Const	**$ 244**	**$ 1,552**	**$ 38**	**$ 1,834**	
P&C	**$ 380**	**$ 2,142**	**$ 291**	**$ 2,813**	
Overall Total	**$ 624**	**$ 3,694**	**$ 329**	**$ 4,647**	

- **Assumptions**

Alternative 1 - Recommendation
  o Project engineering is completed in 2016.
  o Construction starts in 2017 and completed in 2018 in conjunction with the planned Unit #1 outage in the spring.

Alternative 2 - Do Nothing
  o Switchyard 138kv bus fault occurs in 2017 and T-G back-up DC lube oil pump system assumed to fail resulting in the following:
  o Risk of failure is 0.1%
  o T-G repairs estimated at $135,000k
  o Forced outage time estimated at 24 months
  o T-G bearing journal damage
  o T-G structural foundation damage
  o Turbine blade tips destroyed
  o Turbine rotor bowing and hard spots
  o Turbine stationary components extensive damage
  o Generator field and stator rewind
  o Generator exciter extensive damage

Alternative 3 – Next Best Alternative
  o Project engineering is completed in 2016.
  o Construction starts in 2017 and completed in 2018 in conjunction with the planned Unit #1 outage in the spring.

- **Environmental**
This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
If the project is not completed, we will continue to experience 138kv switchyard forced outages and uncontrolled Unit 1 shutdowns which present severe risks to the boiler and potential catastrophic damage to the turbine-generator.

Conclusions and Recommendation Arbough

It is recommended that the Investment Committee approve the Ghent 138kv Switchyard Reconfiguration project for $4,647k to enhance the reliability of the transmission system and minimize the risk of potential catastrophic damage to GH1 turbine-generator.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Existing Layout:
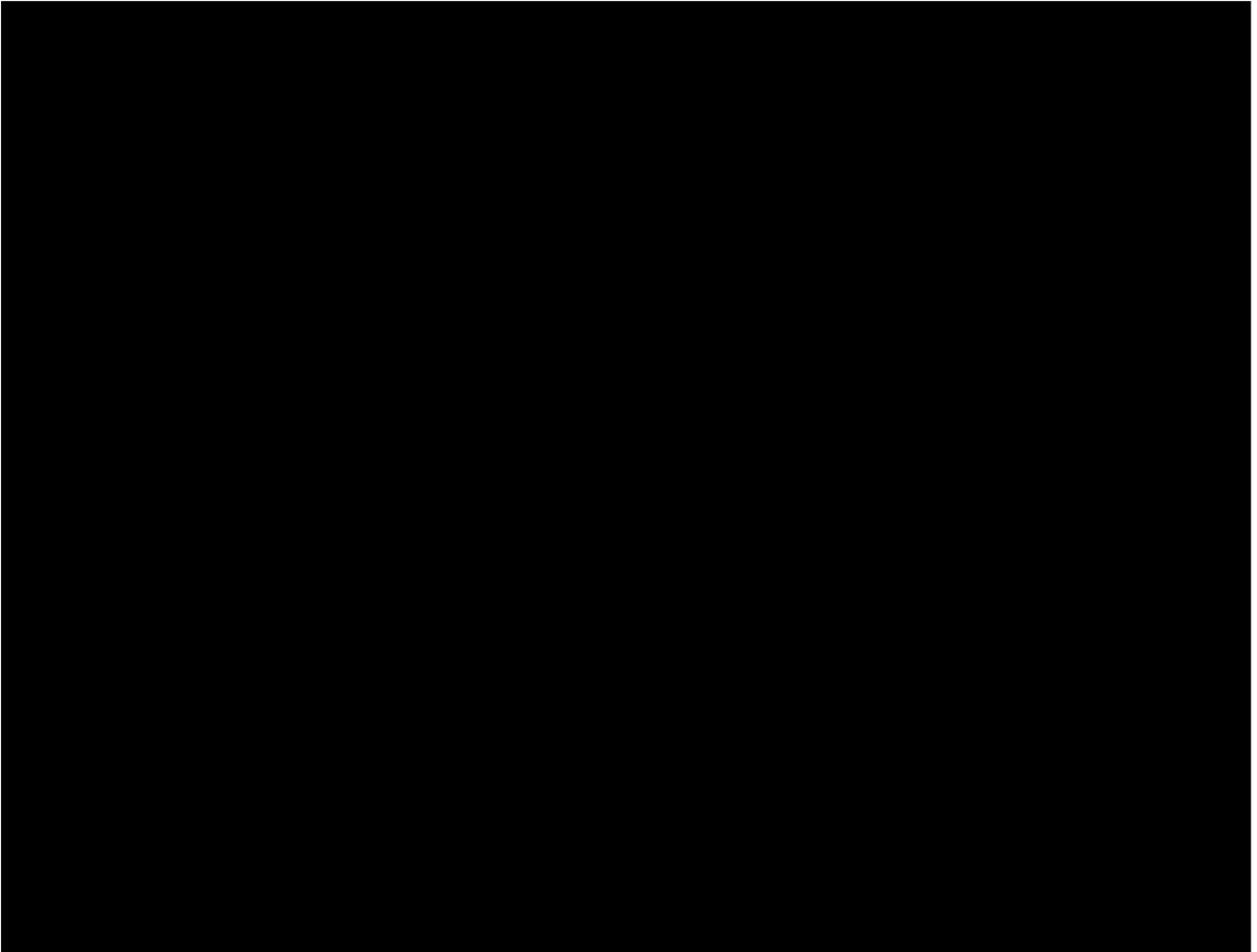
Proposed Layout:
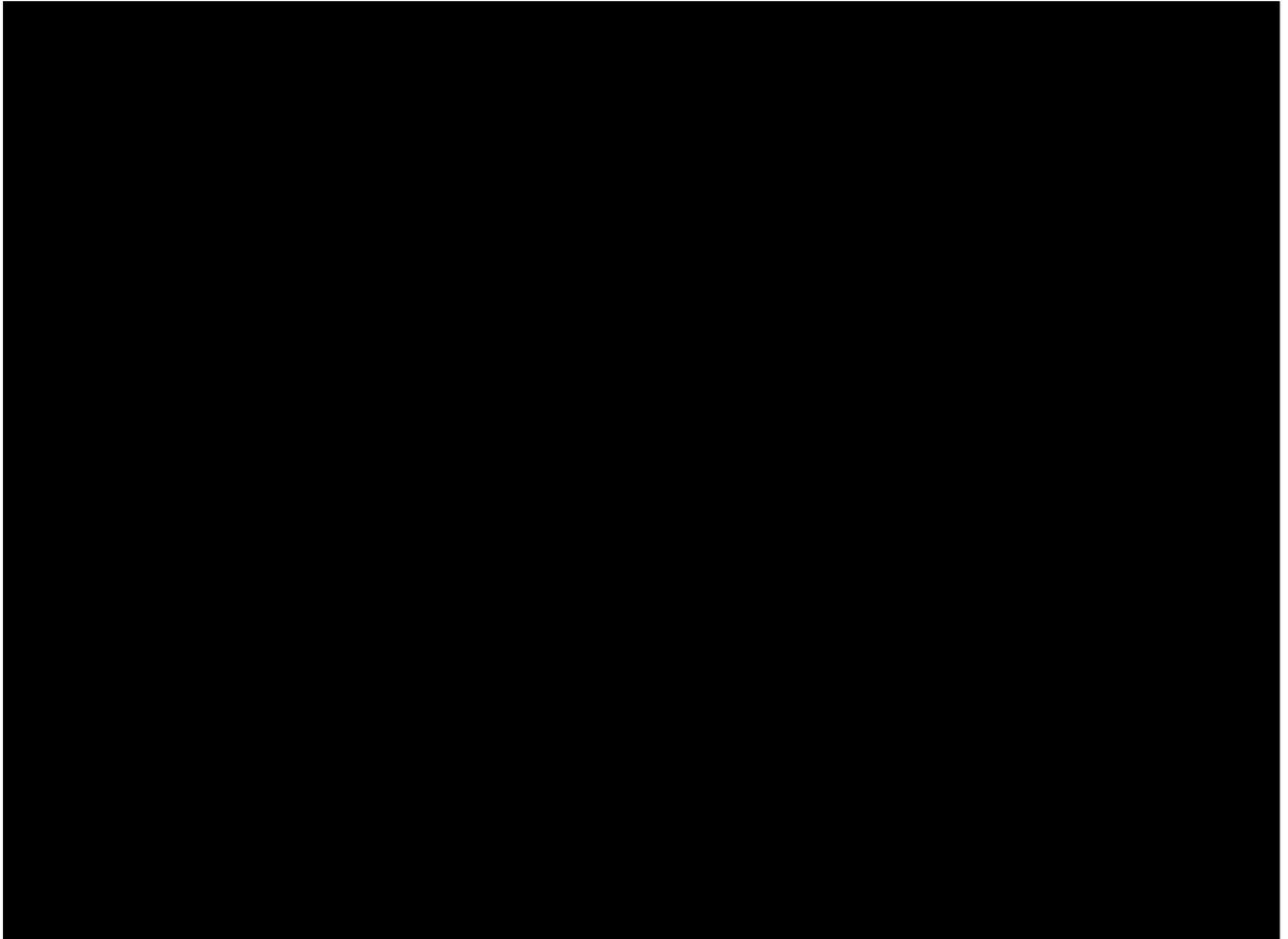
Investment Proposal for Investment Committee Meeting on: <u>25 April 2018</u>

Project Name: <u>GH CY Transfer Point Upgrade</u>

Total Expenditures: <u>$3,713k (Including $338k of contingency)</u>

Project Number(s): <u>152862</u>

Business Unit/Line of Business: <u>Generation</u>

Prepared/Presented By: <u>Christina Schwind/Steve Turner</u>

Executive Summary

This project is to replace the existing transfer point load zones and skirt boxes in the Ghent Coal Handling System with functionally equivalent upgraded equipment. The existing transfer point load zones and skirt boxes have reached the end of their useful lives. These original pieces of equipment require frequent repair, cause significant amounts of coal spillage and create operational issues. Ghent's entire 2,000 MW output requires a reliable Coal Handling System to supply fuel to each of the four coal-fired generating units. The outdated transfer points jeopardize the reliability of this critical system. This project consists of replacing all existing transfer point load zones and skirt boxes, except those located in the Sample House and 10,000 ton silo, with updated equipment. Since the transfer points in the Sample House are newer and the equipment is dissimilar, the Sample House is not included in this project. The transfer points in the 10,000 ton silo will be executed with a future project to optimally manage the scheduling of work with coal yard operations.

A total of $3,257k for this project in 2018 was included in the 2018 BP. The additional $456k necessary to complete this project will be funded by the plant. Ghent's Coal Handling System will continue to experience decreased reliability and increased operations and maintenance costs until the transfer points are upgraded.

Background

The four units at Ghent Generating Station can burn more than 20,000 tons of coal a day. All coal is supplied to the units via Ghent's Coal Handling System. The existing coal transfer points within this system are original and require frequent repairs in order to meet the station's fuel handling needs. As well as the increase in repair requirements, coal spillage, chute plugging and premature belt wear can also be attributed to the age and design of the current transfer points. These outdated pieces of equipment also create problems downstream of the conveyor system. Detached components can travel through the system and cause plugging in a unit's gravimetric coal feeders and pulverizers. Note that the design of the new transfer points will allow for a more centered load on the conveyor belts, reducing coal spillage, chute plugging and premature

belt wear. More durable material has been selected for the new design, increasing the life of the components and reducing the frequency of repairs. In addition, the new design allows for repairs to be made from the exterior of the transfer point which reduces maintenance hours and the need for confined space entry. Replacing the transfer points in Ghent's Coal Handling System with upgraded equipment is necessary to regain operational reliability and decrease maintenance and cleaning costs.

- **Alternatives Considered**
    1. Replace the identified coal transfer points with functionally equivalent upgraded equipment.
        a. This is the best (recommended) option because it addresses the current issues with the existing transfer points and has the lowest NPVRR.
        NPVRR: ($000s) $2,039k
    2. Defer project until 2025.
        a. This option will address the current issues with the existing transfer points but will require the plant to continue to experience incremental maintenance costs and decreased system reliability until the project is completed in 2025.
        NPVRR: ($000s) $2,118k
    3. Do nothing.
        a. The existing transfer points are at the end of their useful lives. The age and design of the existing components cause operational and maintenance issues. If the equipment is not replaced, the system will continue to experience decreased reliability and increased maintenance costs.
        NPVRR: ($000s) $3,636k

Project Description

- **Project Scope and Timeline**
    The scope of this project includes the engineering, procurement and construction required to replace the existing coal transfer points at Ghent Station. This project is similar to smaller projects that have been implemented at other stations in the fleet. All Vendors that were invited to bid the material supply and construction for this project have experience in the industry. Current system drawings and operating parameters have been provided to the Vendors to ensure that the new equipment is sized, designed and installed properly.

    - April 25, 2018 – Investment Committee meeting and approval
    - May 1, 2018 – Bid award date; Issue contract
    - May 2018 – Project kick-off, begin engineering and procurement
    - June 2018 – Begin construction
    - September 1, 2018 – All outside (coal yard) construction and testing complete
    - November 30, 2018 – Units 1-4 coal rooms construction and testing complete
    - December 2018 – Project complete

- **Project Cost**

The total cost of the project is $3,713k and includes 10% contingency. The contingency amount was determined based upon the risk associated with the project and common contingency levels of projects of similar size. The material supply and construction package was bid as a lump sum.

Economic Analysis and Risks

- **Bid Summary**

The request for proposal (RFP) was issued to four (4) contractors specializing in this type of work: ███████████████████████████ A pre-bid meeting was conducted on February 5, 2018. Three (3) of the four (4) solicited bidders returned a bid by the due date, February 21, 2018. Additional pricing for Scope of Work (SOW) modifications was requested from ████ and will be provided by April 20, 2018.

Competing Bids			
Co. 1	Co. 2	Co. 3	Co. 4
███████	███████	████████	███████
████	██████	█████	

In addition to pricing, proposals were evaluated based on technical approach, proposed warranty and liquidated damages, conformity to the scope of work, proposed material suitability, experience, commercial terms, and safety. Overall, ██████ was found to have the preferable bid (see Attachment 1 - Bid Pricing Comparison) based on input from the Commercial, Engineering, and Operations departments. The ██████ proposal is fully compliant with both the scope and schedule. It includes schedule liquidated damages and a performance guarantee, as well as a 10 year material and workmanship warranty on the ceramic liners and a one year material and workmanship warranty on all other upgrades.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	3,106				3,106
2. Cost of Removal Proposed	607				607
3. Total Capital and Removal Proposed (1+2)	3,713	-	-	-	3,713
4. Capital Investment 2018 BP	2,884				2,884
5. Cost of Removal 2018 BP	373				373
6. Total Capital and Removal 2018 BP (4+5)	3,257	-	-	-	3,257
7. Capital Investment variance to BP (4-1)	(222)	-	-	-	(222)
8. Cost of Removal variance to BP (5-2)	(234)	-	-	-	(234)
9. Total Capital and Removal variance to BP (6-3)	(456)	-	-	-	(456)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s): Arbough

Discount Rate: 6.58%

Capital Breakdown:

Labor:	$21
Contract Labor:	$1,804
Materials:	$1,530
Local Engineering:	$0
Burdens:	$20
Contingency:	$338
Reimbursements:	($0)
Net Capital Expenditure:	$3,713

- **Assumptions**
  - Recommendation – Replace the identified transfer points with upgraded equipment
    The capital evaluation model assumes that the project will be complete by the end of 2018. A savings in maintenance and cleaning costs of $20k in 2018 and $112k per year after 2018 is assumed. The model assumes 3% inflation.

  - Alternate #1 – Defer project until 2025
    The capital evaluation model assumes that the project will be complete by the end of 2025. Until the project is completed in 2025, the model assumes a 5% probability of Ghent 1 being unavailable for 2 days in the event that a repair requires the coal conveyor to be taken out of service. The model also assumes an incremental maintenance cost of $10k per year through 2025. After 2025, a savings of $138k each year in maintenance and cleaning costs is assumed. The model assumes 3% inflation.

  - Alternate #2 – Do nothing
    The capital evaluation model assumes a capital expenditure every third year to replace a conveyor belt due to premature wear. The model assumes a 5% probability of Ghent 1 being unavailable for 2 days in the event that a repair requires the coal conveyor to be taken out of service. The coal conveyor system that feeds Ghent 1 has less redundancy than Ghent 2, 3 and 4. An incremental maintenance cost of $10k per year is assumed. The model assumes 3% inflation.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	No
#3	Does the project increase through-put with any of the material handling systems?	No

#4	Will the project affect the dispatch order or utilization of the unit?	Although / No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes Repaired on a yearly basis
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

The Ghent Environmental Supervisor has reviewed this project.

- **Risks**
  The recommended Vendor is familiar with the maintenance and operation of the Coal Handling System at Ghent Station and has experience supplying comparable systems with similar technology with good results. Improved reliability and reductions in maintenance and cleaning costs are expected with a high degree of certainty. Risks to the proposed project schedule include weather impacts and scheduling conveyor downtime without interfering with plant operations. If the project is not completed, Ghent Station will continue to experience higher maintenance, cleaning and operations costs associated with the aged transfer points in the fuel handling system.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the GH CY Transfer Point Upgrade project for $3,713k to reduce maintenance costs and improve operability of Ghent's Coal Handling System.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

gh

Arbough

Investment Proposal for Investment Committee Meeting on: <u>6/27/2018</u>

Project Name: <u>GH Stacker Reclaimer Recert</u>

Total Expenditures: $9,223k   (Including $310k of contingency)

Project Number(s): 140202

Business Unit/Line of Business: Generation

Prepared/Presented By: <u>Stephen Nix/Steven Turner</u>

Executive Summary

This project is for the recertification of the Ghent Bucketwheel Stacker Reclaimer (BSR). The scope of this project includes the engineering, fabrication, procurement and construction required to refurbish, replace or upgrade BSR components. Completion of this project will help ensure reliability of the Ghent coal handling system well into the future.

Six million tons of coal is burned each year at Ghent Station and the BSR handles all coal that is placed on the coal pile. The BSR has been in service since 1973 and has begun to exhibit signs of degradation and component failures in the past several years. During BSR outages, coal is loaded to the Ghent units either from the coal silo, two reclaim coal yard hoppers or is conveyed directly to the Ghent units from the Continuous Barge Unloader. These methods of coal loading are less efficient than using the BSR, and could ultimately result in unavailability of a Ghent Unit. Replacement with a new BSR and "Do Nothing" with continued maintenance of the existing BSR were alternatives considered.

A total of $7,225k was included in the 2018BP for recertification of the BSR based on initial estimates of the scope. An updated scope of work was developed after a detailed condition assessment was performed in January 2018. The project was bid as a turnkey project including the engineering, fabrication, procurement, management and construction required to complete the work. A competitive bidding effort of the work identified by the condition assessment led to the current proposed project cost of $9,223k. The additional funding is proposed in 2018, and has been requested and approved by the Resource Allocation Committee.

Background

The Ghent Station Heyl & Patterson designed BSR was constructed in the early 1970's and began operation in 1973 with the station's first generating unit. The BSR receives coal from the Continuous Barge Unloader via a series of conveyor belts and discharges (stacks) onto the coal pile. This equipment can remove (reclaim) coal from the stacked pile with its rotating bucketwheel which deposits coal back onto the BSR's reversible conveyor. This reclaimed coal

is routed to the four Ghent units. The BSR must be in service for coal to be stacked on the coal **Although** pile for storage at Ghent Station.

The BSR has operated reliably with various repairs, replacements and upgrades to keep this equipment in good working condition. The BSR is inspected annually and areas of concern have been noted and corrected as needed to ensure the reliable and safe operation. Over the years, coal accumulation on structural members has caused heavy rusting and severe deterioration in certain areas and other areas have moderate rusting that must be addressed. Gradual deterioration of the coal conveyors on the BSR has caused increased spillage, which piles coal on walkway grating, structural members, cable tray and other components, creating a personnel and fire hazard.

Well managed fuel handling with highly reliable equipment is necessary to unload, store, and reclaim coal to operate the Ghent units under full load conditions. At best, while operating with four units at full load for an extended period of time, coal pile inventory will be reduced even with highly reliable and efficient operations of the BSR. Up until now, the BSR has been able to support the four Ghent units averaging 85% of full load and also slowly build coal pile inventory, when necessary, to compensate for coal yard outages when coal cannot be unloaded and stacked. However, corrosion and wear on the 45 year-old BSR's basic structure and components continue to deteriorate it to the point where lower reliability in the future will cause the coal pile to be diminished and affect availability of the coal generating units.

The most recent Heyl & Patterson Evaluation Findings Report from the January 2018 inspection provided recommendations for the BSR recertification to extend serviceable life for the next thirty years.

- **Alternatives Considered**

In addition to the recommended work, two additional cases are considered in the CEM. "Do Nothing" is an alternative that continues to maintain the equipment as done in the past but equipment reliability further declines since the required repairs are much more involved than an O&M program can provide. Replacing with a new BSR was also evaluated but has a longer installation time and higher cost.

1. Recommendation: NPVRR: ($000s) <u>10,470</u>

2. Alternative #1: Do Nothing   NPVRR: ($000s) <u>11,873</u>

   [This alternative should not be chosen because the BSR has been exhibiting signs of damage for several years and poses a risk to operations and the BSR operators.]

3. Alternative #2: Total Replacement   NPVRR: ($000s) <u>16,334</u>

   [This alternative should not be chosen due to project costs much greater than the recommendation. Also, this alternative would delay the project at least one year

allowing the BSR to further degrade and continue to pose a risk to operations **Although** BSR operators.]

Project Description

- **Project Scope and Timeline**

The scope of this project includes the engineering, procurement, fabrication and construction to refurbish, replace or upgrade BSR components. The scope is as recommended in a January 2018 condition assessment report.

Replacements that have been identified for the BSR include major structural components including travel trucks, trailing structure and boom. Other replacements include an operator's cab upgrade, electrical house, PLC and controls, wiring and conduit, cables and trays, hydraulic piping, fire protection piping, sensors, lighting, walkways, certain wear components, and outdated and obsolete equipment. All motors will be reconditioned or replaced.

Engineering and fabrication will begin in the latter half of 2018 with removal and installation in early spring 2019.

Milestones:
- June 2018 – Investment Committee meeting requesting approval
- July 2018 – Issue contract
- July 2018 – Project kick-off, begin engineering, fabrication & procurement
- January 2019 – Midpoint fabrication
- April 2019 – Complete fabrication; Site deliveries
- May 2019 – Begin 2019 Removal/Installation work
- July 2019 – Complete installation

- **Project Cost**

The total project cost is $9,223k, based on a firm price turn-key contract. The fabrication cost is $4,307k and the contractor installation cost is $4,419k. Miscellaneous expenses are estimated to be $187k. A contingency of 5% of 2019 cost ($310k) will cover any unknown conditions discovered once the work begins that would be directly related to the scope of the Project. Any additional work discovered during the Project will be completed on a Firm Price or T&M basis.

Economic Analysis and Risks

- **Bid Summary**

The project was bid as a turnkey project including the engineering, fabrication, procurement, management and construction required to complete the work. Proposals were solicited from companies that supply and refurbish this line of equipment which included ▮▮▮▮▮▮▮▮▮

�no . These companies were represented at the prebid Although
meeting. ▮▮▮▮ declined to bid days later, preferring to furnish new equipment in lieu of
a rebuild. Late in the bidding schedule, ▮▮▮ requested a six week bid extension that was
denied by KU in order to maintain project schedule. It should be noted that ▮▮▮ had been
the high bidder on the recent similarly scoped Continuous Barge Unloader Recertification
project. After attending the prebid, ▮▮▮▮▮ was not responsive and did not submit a bid.
Negotiations with ▮▮▮▮▮▮ have successfully concluded with a base bid price of
▮▮▮▮ .

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	3,462	4,416			7,878
2. Cost of Removal Proposed		1,345			1,345
3. Total Capital and Removal Proposed (1+2)	3,462	5,761	-	-	9,223
4. Capital Investment 2018 BP	1,444	5,781			7,225
5. Cost of Removal 2018 BP					-
6. Total Capital and Removal 2018 BP (4+5)	1,444	5,781	-	-	7,225
7. Capital Investment variance to BP (4-1)	(2,018)	1,365	-	-	(653)
8. Cost of Removal variance to BP (5-2)	-	(1,345)	-	-	(1,345)
9. Total Capital and Removal variance to BP (6-3)	(2,018)	20	-	-	(1,998)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$92
Contract Labor:	$5,025
Materials:	$3,711
Local Engineering:	$74
Burdens:	$11
Contingency:	$310
Reimbursements:	($0)
Net Capital Expenditure:	$9,223

- **Assumptions**

  The CEM is based on unavailability of the Ghent units due to degrading BSR reliability.

  Availability Disimprovement in Weeks:
  As the condition of the BSR degrades and reliability decreases, an annual decrease in coal pile inventory at the normal burn rate would eventually cause a one week/year shortage of coal supply to the four units.

  Probability %:
  A rate of decrease in current BSR reliability was assumed that after twenty-five years would cause the one week of Ghent plant Availability Disimprovement.

  The CEM model uses Ghent Unit 3 unavailability (highest dispatch cost) x four units. Note that the equivalent value for # of weeks x probability (i.e.: 4 weeks x 1.0 = 8 weeks x 0.5) is used in the CEM model at twenty-five years.

  Unbudgeted O&M Costs assumed for both alternatives are based on miscellaneous repairs related to the BSR which are assumed to increase in scope 3% per year.

  Alternative #2 assumes a completely new BSR and associated conveyors and structures would cost $13,000k.

  Inflation is not considered in the alternatives since they are not included in the CEM model's built-in unit annual availability improvement $000s.

  Additional information regarding the CEM assumptions is contained in Appendix A

- **Environmental**

  Lead abatement is included in the contractors work scope for this project.

  Items suspected of containing asbestos will be tested and abated as required. EPA rules requiring 10 day notification for demolition of load-supporting structural members is not considered relevant as this is a piece of equipment and not a facility.

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	Yes
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	

		Arnough
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes see below
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

Item #7a.

Previous upgrades:	Cost
2016/2017 Hydraulic System	$133k
2015 Project 140031 GH S/R MCC Repl	$226k
2013 Project 142811 GH S/R Elevating Conv Chute Repl	$67k

The Ghent Environmental Supervisor and Environmental Affairs have reviewed and approved this project.

- **Risks**

If this project is not completed, continued corrosion and degradation of the BSR will occur which will increase frequency of repairs and downtime. If not addressed, downtime of the BSR will increase to the point that coal pile inventory will be diminished and unit availability will be affected.

In the event a critical structural failure occurs, it will likely happen when under stress from loaded operating conveyors. In this scenario, the momentum of the moving belts could cause multiple failures in a chain reaction. Repairs will be much more extensive and costly.

The degraded condition of coal transfer points and skirting causes coal spillage onto equipment, cable tray, walkways and stairs. This creates corrosive conditions for equipment and fire hazards. This is also a safety concern for personnel walking on surfaces or working on the equipment.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the <u>GH Stacker Reclaimer Recertification</u> project for $9,223k to safely and reliably supply coal to the four units at Ghent.

<u>Approval Confirmation for Capital Projects Greater Than $2 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:

kent Blake   6/28/2018 | 1:26 PM EDT

Kent W. Blake   Date

Chief Financial Officer

DocuSigned by:

Paul Thompson   6/28/2018 | 2:29 PM EDT

Paul W. Thompson   Date

Chairman, CEO and President

Appendix A
Ghent Bucketwheel Stacker-Reclaimer (Stacker) CEM Analysis
Project 140202

Basic Operations Assumptions:

4 units at full load require 21,120 tons/day
Barge size is 1500 tons
The 2019 unit outage schedule is assumed every year
The coal inventory analysis starts January 1, 2019 with 600,000 tons in storage

CEM Recommendation Scenario (Normal burn rate, Stacker out of service 2 in 10 days)

In the recommended scenario, it is assumed that the condition of the Stacker reaches a point such that maintenance requires it to be out of service 20% of the time. When the Stacker is out of service, all coal from the barge unloader goes directly to the unit bunkers but coal unloading is reduced 50% due to the complexity of directly loading available coal bunkers on the units. The balance of coal to load bunkers is reclaimed from the pile using earth-moving equipment. The barge unloader would need to average 14.4 barges/day, when the Stacker is available, to keep up with this normal burn rate scenario, however, this is more than the 14 that can be maintained over an extended period of time and the end of year coal pile inventory is reduced by 130k tons. After the summer 2019 run, coal pile storage dips under 180k tons (8.5 days) which means after the summer run in 2020 with the Stacker in this condition dips under 40k tons (2 days). Coal inventory is 0 after the third quarter of 2021 and no coal can go to the unit during the final week of the barge unloader outage. This one week occurrence with no units on line repeats every year. This theoretical case of no available coal supply could actually be exacerbated by external factors such as river conditions or barge delivery issues.

The Capital Evaluation Model is based on the following calculations and assumptions:

o   Almost six million tons of coal burned per year (four units each at 85% of full load for 331.75 days/year)
o   Barge unloader unavailability (3 days/month plus 3 weeks/year during coal yard outage)
o   Barge unloading rate
    o   14.1 barges per day with BSR in service
    o   7 barges per day during periods with BSR out of service
o   Stacker Reclaimer calculations that result in coal shortage
    o   BSR out of service 20% of the time will cause 1 week/year without coal starting in 2021.
o   Stacker Reclaimer unavailability
    o   Unavailability currently at 1 day out of service per month increasing at a constant rate to 3 days out of service per month in 10 years. In 25 years the BSR will reach the point of being out of service 20% of the time.
o   The Do Nothing case utilizes a fractional probability of an 8 week plant-wide outage in the CEM in order to allow for the increasing duration of time without coal without exceeding 100% probability.
o   Unbudgeted O&M Costs assumed for both alternatives are based on $50k miscellaneous BSR repairs/year which are assumed to increase in scope 3% per year.

Investment Proposal for Investment Committee Meeting on: <u>December 19, 2016</u>

Project Name: <u>Hume Road Transformer Addition</u>

Total Expenditures: <u>$6,925k (includes $630k contingency)</u>

Project Number(s): <u>Substation-144909, Distribution-152840, Transmission-137754</u>

Business Unit/Line of Business: <u>Electric Distribution Operations</u>

Prepared/Presented By: <u>Jim Burns/Beth McFarland</u>

Executive Summary

Electric Distribution Operations (EDO) Electric Engineering and Planning (EEP) seeks funding authority to complete the necessary substation, transmission line, and distribution circuit improvements to meet the aggressively growing electrical service needs of customers in the Hamburg Area located on the east side of Lexington in Fayette County. The existing Hume Road 12kV substation serves 2,169 commercial and residential customers and the substation transformer is projected to exceed Distribution Planning's winter loading limit of 120% of the 22.4 MVA top nameplate during winter 2018/2019. The Hamburg area in Lexington is a fast growing and highly visible commercial and residential area with substantial land available for development and an active development plan. This area is expected to continue to grow at an above average pace well into the future. This Investment Proposal provides for the addition of a new transformer in the Hume Road substation, transmission protection enhancements, upgrade of an existing distribution feeder circuit and construction of a new feeder circuit to meet the long term load growth in the area. This construction also removes the Hume Road and Liberty Road substations from the Distribution Substation Transformer Contingency Program (N1DT) list (transformers that cannot be fully backed up for a failure of a substation transformer during high load periods) and provides distribution and transmission reliability enhancements for this substation. Project completion is expected by the end of 2018.

Funding is requested in the amount of $6,925k to complete the system enhancements for the Hume Road substation. This project is in the 2017 Business Plan (BP) for $6,927k. $5,878k is in the 2017 EDO BP ($2,001k-2017, $3,877k-2018) and $1,049k is in the 2017 Transmission BP ($148k-2017, $901k-2018).

Background

The Hume Road 12kV substation serves 2,169 customers and consists of a 22.4 MVA, 69-12kV transformer and four feeder breakers. It is located on the east side of Lexington on Winchester Road east of I75 in Fayette County. The Hume Road substation transformer reached 117% of its 22.4MVA top nameplate rating during the extreme cold of the winter 2014/2015, and is

forecasted to reach 124% during Winter 2018/2019 under normal winter loading conditions. Although Distribution Planning winter loading limit for substation power transformers is 120%. This area of Lexington, commonly referred to as the Hamburg area, has grown aggressively over the last two decades, causing continued construction of new substation and circuit facilities at area substations including Bryant Road, Lakeshore, and Hume Road substations. As a result of the rapid growth, two area substations, Hume Rd. and Liberty substations are currently on EDO's N1DT list.

A majority of the land that is available for development of additional commercial and residential load in this area will be served by the Hume Road substation. The most active recent growth, as well as expected immediate future growth, is on Hume road circuit 193, which carried 60% of conductor capacity during the winter 2015/2016. In addition to providing more transformer capacity at Hume Road, this forward-looking plan includes more circuit capacity to feed future heavy development and provides loading relief for circuit 193. The capacity addition and circuit improvements will remove Hume Rd. and Liberty substations from EDO's N1DT list. Transmission improvements associated with this project will provide enhanced reliability for the Loudon Ave. to Winchester 69kV line by replacing existing 69kV motor operated disconnects (MODs) with ring bus configured breaker protection.

The recommendation of this investment proposal is to expand the existing Hume Road Substation by adding a new 69-12kV, 37.3 MVA transformer and associated switchgear in the Hume Road substation. This will eliminate all overload conditions, provide full contingency for the loss of a transformer at both Liberty Road and Hume Road substations and provide distribution and transmission reliability improvements.

A Transmission Service Request for a new service point at the Hume Road substation will be submitted to TranServ International. Other than the planned transmission costs to connect the new service point no additional costs are expected for transmission improvements.

- **Alternatives Considered**

1. Recommended Option**:**   NPVRR: ($000s) $7,942
   EEP's recommended option is to install a 69-12kV, 37.3 MVA transformer in the Hume Road substation, install three 69kV breakers and complete the previously planned 69kV ring bus (the existing substation was designed for a future ring bus configuration), install new 12kV switchgear with one 2000 amp main breaker and three 1200 amp line breakers. Also recommended is the upgrade of 2,900 feet of 1/0 Copper overhead circuit to 795kCM Aluminum and construction of 9,600 feet of a new 795kCM Aluminum feeder circuit. This project provides adequate capacity for new growth, distribution and transmission reliability improvements and full year contingency capacity for both the Liberty Road and Hume Road substations. These substations are currently on EDO's N1DT list where a portion of customers would remain without service for up to 36 hours in the event of a transformer failure or outage. The estimated total cost of this option is $6,925k.

2. Do Nothing Option: NPVRR: ($000s) N/A
   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating

limits for distribution substation power transformers, and this practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset. Although

3. Upgrade Hume Road 549-1 transformer to 37.3 MVA.   NPVRR: ($000s) $12,758
This alternative proposes to replace the existing 22.4 MVA transformer at Hume Road with a 37.3 MVA unit to address transformer overloading. The same distribution circuit and substation feeder work described in the preferred option is recommended in this option to adequately meet future load growth. This option is not equivalent to the recommended option because it does not provide the same level of new capacity (14.9 MVA verses 37.3 MVA), the full improvements in distribution or transmission reliability, or remove the Hume Road transformer from EDO's N1DT list. Failure of the existing Hume Road transformer would result in an extended outage of up to 36 hours until a new transformer or mobile transformer could be installed. While the loss of an entire substation is a relatively low probability event in any given year, planning studies indicate an outage of the Hume Road substation at peak would cause as much as 16,300 kW to go unserved until the station is restored. Using the corporate "Cost of Unserved Energy" ($17.2/kWh) with estimated loads going unserved at peak for 24 hours, the minimum Cost of Unserved Energy would be $6,729k. The estimated annualized Cost of Unserved Energy based on an annual 5% probability of an outage is $336k. The estimated total capital cost for this option is $5,345k.

Project Description
- **Project Scope and Timeline**

  o Substation project #144909: Install a 37.3 MVA 69-12kV LTC transformer, new 12kV switchgear with 2000A main breaker and three 1200A line breakers. Install three 69kV breakers and tube bus to complete a ring bus substation configuration. This estimate includes funds for labor, primary equipment, protection and control, material, and wildlife protection for a 37.3 MVA transformer. The total estimated substation cost is $4,300k.
    - Mar-Dec 2017: Complete engineering and design. Specify and order all material and equipment. Receive material and equipment. Begin site preparation and foundations.
    - Jan-Dec 2018: Complete foundations and install transformer, switchgear/breakers, 69kV tube bus and all associated materials and equipment. Complete all secondary and protection and control work. Commission and energize the station.
  o Distribution project #152840: Replace 2,900 feet of 1/0 Copper conductor on an existing circuit with 795kCM Aluminum and construct a new 9,600' 795kCM Aluminum circuit. Install four manholes and three new exit circuits. The total estimated distribution cost is $1,576k.
    - Jan-Dec 1, 2018: Design and complete all distribution circuit construction.
  o Transmission project #137754: Rework existing self-supporting tap pole for an in-and-out 69kV circuit configuration. Remove two motor operated switches. Install tap for new delivery point and upgrade 3,900 feet of transmission line along Winchester Road to allow new double circuit distribution under build. The total estimated transmission cost is $1,049k.

- Oct-Dec 2017: Order poles, conductor and materials.   **Arbough**
- Jan-Mar 2018: Complete construction.

- **Project Cost**
  The total estimated cost to complete the Hume Road Transformer Addition project is $6,925k. The transmission, substation and distribution cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% of contingency ($630k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  Transmission, Substation, and Distribution will use existing material and labor contracts and follow established Supply Chain procedures. KU Company crews will be utilized based on availability at the time of work.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,148	4,656			6,804
2. Cost of Removal Proposed	-	121			121
3. Total Capital and Removal Proposed (1+2)	2,148	4,777	-	-	6,925
4. Capital Investment 2017 BP	2,149	4,778			6,927
5. Cost of Removal 2017 BP	-	-			-
6. Total Capital and Removal 2017 BP (4+5)	2,149	4,778	-	-	6,927
7. Capital Investment variance to BP (4-1)	1	122	-	-	123
8. Cost of Removal variance to BP (5-2)	-	(121)	-	-	(121)
9. Total Capital and Removal variance to BP (6-3)	1	1	-	-	2

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:

Labor:	$ 238
Contract Labor:	$ 2,610
Materials:	$ 2,530
Local Engineering:	$ 592
Burdens:	$ 288
Contingency:	$ 630
Transportation:	$ 37
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 6,925

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The project will be completed in time to meet load demands.
  - No significant unknown costs for transmission improvements will be associated with the addition of a new service point.

- **Environmental**
  - There are no known environmental issues at this time.

- **Risks**

  Failure to complete this project before winter 2018/2019 will result in substation transformer loading above normal operating limits and escalate the potential for failure of the existing Hume Road substation transformer, resulting in an extended outage for up to 2,169 customers.

Conclusions and Recommendation

EDO EEP recommends that the Investment Committee approve the Hume Road Transformer Addition project for $6,925k to prevent the overloading of the Hume Road transformer, improve distribution and transmission reliability, ensure adequate capacity for future load growth in the Hamburg area of Lexington and remove Hume Road and Liberty Road substations from EDO's N1DT list.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: December 18, 2015

Project Name: Kentucky Wired Fiber Make-Ready Project

Total Expenditures: $4,000k ($2,000k net of reimbursement)

Project Number(s): KU: 150218,150221, LG&E 150220,150222

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Robby Trimble

Executive Summary

KU and LG&E Electric Distribution proposes to invest up to a combined total of $4,000k on make-ready work associated with KentuckyWired, the Commonwealth's fiber optic cable installation project that will interconnect every county in the state. The $4,000k investment will be split into two investment work types: reimbursable and non-reimbursable work. KU/LG&E will invest up to $2,000k (non-reimbursable) on the replacement of poles determined to be in a pre-existing defective or pre-existing overloaded condition; in addition, KU/LG&E will invest up to $2,000k on fully reimbursable work tasks.

The Commonwealth has scheduled the KentuckyWired infrastructure installation for November 2015 through December 2018. Installing the new fiber optic cable on an existing route requires "make-ready" work: this work consists of all engineering, design, and construction necessary to prepare and make space on LG&E/KU poles for the new third party (KentuckyWired) pole attachments; this work ranges from raising a neutral conductor to complete pole replacement.

The $2,000k non-reimbursable investment is considered the maximum out-of-pocket capital expenditure borne by the Company to replace pre-existing priority defective poles and poles found to be in a pre-fiber overload condition. Pole integrity will be determined by Ledcor, a technical infrastructure consortium that includes Black & Veatch (B&V); B&V will perform load analysis and submit the results to KU/LG&E for verification and agreement.

The $2,000k reimbursable investment is for the recovery of chargeable employee and Company contractor time and materials. Labor charges are expected for, but not limited to, engineering design and review including survey work, asset management and administration, inspection services, dispatching services, procurement, and associated overheads. Additionally, the Company will be reimbursed for labor and material charges for any make-ready or transfer work performed by the Company's resources that does not fall under the agreement in regards to Company-owned pre-existing priority defective and overloaded poles. The Tax Department's belief is that this reimbursement will not be taxable, because this project should qualify as being for the public good since it is driven by the state.

To minimize the impact to Company resources, an agreement with KentuckyWired allows the Although third party attachee to operate under "turn-key" provisions (engineering/construction) with Company oversight; the necessary make-ready work will be executed by direct-hired electrical contractors from a list of those contractor companies approved to work on Company facilities.

LG&E/KU have agreed to waive typical pole attachment fees in exchange for 12 strands of dark fiber installed continuously across the entire "backbone" network and where needed on laterals (LG&E/KU will work with KentuckyWired to determine which laterals LG&E/KU will utilize; LG&E/KU will use all dark fiber received solely for internal use). In this agreement, dark fiber refers to fibers within KyWired's communication cable that are reserved for the exclusive use of LKE. The estimated value of the dark fibers in terms of avoided capital and O&M costs for the Company in the five year business plan (2016-2020) is $2.7M ($988k O&M and $1,688k Capital) compared to the estimated $196k annual cost of the pole attachment fees. See attachment for analysis of value. These values are subject to change based on changes in scope and schedule for the KyWired project. This portion of the agreement is taxable.

This project was not included in the 2016 Business Plan (BP) and the incremental funding will be approved through the Corporate RAC process in 2016 ($1.2M for 2016 spending). 2017 and 2018 spending will be incorporated into the 2017 BP.

Background

KU and LG&E have entered into an agreement with the Commonwealth of Kentucky allowing the state and its representatives to affix fiber optic cable to Company facilities. The mixed public/private project, KentuckyWired, also known as the Next Generation Kentucky Information Highway (NG-KIH), is a Commonwealth initiative to spur high speed internet access to underserved areas and will provide high speed internet access to the Commonwealth's governmental facilities, to public universities, and to school districts in every county throughout Kentucky. The project consists of building a 3,209 mile "middle-mile" fiber network that is designed to provide a cost-efficient solution for third parties to build the "last mile" to customers and businesses in these underserved areas.

The KentuckyWired network consists of a "backbone" network made up of 6 rings stretching across Kentucky. "Laterals" will extend off the "backbone" and eventually reach every county seat. Pre-construction design has already begun in earnest with construction in the Lexington area desired within the 4th quarter of 2015. The first two rings to be built connect 1) Louisville, Lexington, and Cincinnati, and 2) Lexington, Morehead, Ashland, Prestonsburg, Hazard, London, Somerset, and Richmond. These two rings are targeted for completion by April 2016, with the entire network to be complete by the end of 2018. In order to meet the Commonwealth's target dates for completing the network, LKE is stepping outside the typical third party pole attachment process allowing the Commonwealth to self-perform engineering and make-ready construction using certified resources.

The KentuckyWired network will attach to an estimated 27,126 poles in the LKE service territory (22,846 in KU and 4,280 in LG&E) covering about 1,100 linear miles of pole route. It is unknown how many of these poles will be determined to be pre-existing priority defective

poles; external utility pole failure rates range typically from 2 – 3%. KentuckyWired's total project buildout on all Kentucky service territories is for 3,209 miles of fiber optic cable, with an estimated 85% aerial and 15% underground.

The Commonwealth's budget for the completed project is $274.8M. The project rollout should be completed by the end of 2018.

Progression of Company responsibilities related to this project include:

- KU Stone Road will perform a thorough engineering review of the first phase of the KentuckyWired project as it commences since Lexington is the prime hub for the fiber.
- Reviews will be ongoing; the initial review will help determine the future level of involvement needed as the project rolls out to the other service areas.
- Future reviews are envisioned to be undertaken at a much higher level as the Company gains trust in the third-party's process competency.
- KU-Lexington will closely monitor construction in the first phase and formulate a best-practices review to share throughout LKE.
- Initial engineering reviews will be executed by existing KU resources; ensuing review workload will be handled by a mix of KU/LG&E Company and Contract personnel.
- All contractor crews must be passported.
- Company-hired contract inspectors will perform ongoing and post-construction installation quality management to ensure all modifications meet standards and code compliance.
- These third-party pole attachment/make ready inspectors will be sourced via a new Distribution Inspectors Contract.
- Safety will be closely monitored at every stage.
- Any poles identified as being in a pre-existing priority defective or overloaded condition along the route will be reviewed by Company engineering for accurate determination and replaced at no cost to KentuckyWired, up to a total cost of $2.0M.

Additional KentuckyWired responsibilities/general information include:

- B&V will perform make-ready design and pole integrity analysis.
- B&V has setup and will maintain a SharePoint site to post the pole attachment packets for review and approval.
- B&V estimates that 30% of all poles touched will require some make-ready activity.
- KentuckyWired will be responsible for maintaining an inventory/warehouse of material that meets Company standards. Company will provide material list and facilitate relationship with Company suppliers.
- KentuckyWired will provide all necessary documentation required by Company to evaluate and assess the project, including but not limited to as-built drawings and installed material inventory; such submissions will be in format required by LG&E/KU for GIS entry and Property Accounting ease of use.

Benefits of this project include:

- Meeting the Commonwealth's objective.
- Rehabilitation of distribution system.
- Acquisition of dark fibers for Company use.

Alternatives Considered (1-Recommendation, 2-Do Nothing, 3-Next Best Alt)

1. Recommended option: NPVRR: ($000s) $5,351
   Cooperate with the Commonwealth's KentuckyWired project by investing up to $4,000k,
   of which the non-reimbursable amount will not exceed $2,000k.
2. Do nothing option:
   Choose not to cooperate with KentuckyWired's goals. This alternative is not consistent
   with the Company's vision of promoting economic vitality or with the Public Service
   Commission's vision of avoiding duplicity of infrastructure.
3. Participate at other levels of funding; either to exceed the $2,000k threshold or to reduce
   the Company's investment. Work tasks that are considered reimbursable or non-
   reimbursable could be modified from agreement; this alternative is not suggested to avoid
   conflict with the working agreement with KentuckyWired.

Project Description

- **Project Scope and Timeline**

  Scope:
  - Design review, engineering work, miscellaneous administrative charges, and
    construction-related expenditures - including labor and materials – for third-party
    make-ready work on 3,209 aerial miles of distribution circuitry throughout the
    KU/LG&E territory to create space for the attachment of new fiber optic cable.

  Timeline:
  - May 2015: KentuckyWired Kick Off event.
  - August 2015: B&V began compiling pole review data and submitting pole
    attachment review requests.
  - October 2015: KU begins approving first application attachment packages.
  - November 16, 2015: Bowlin Electric to begin make-ready work on KU facilities at
    KentuckyWired's direct expense.
  - January 2016: LKE-funded make-ready to begin; work flow will begin in the
    Lexington area but will migrate to Louisville by June 2016 and to all of the KU
    territory over the course of the 3-year project.
  - Project begins with core ring segments that connect Lexington-Louisville-Northern
    KY and Lexington-Somerset-Hazard-Ashland in 2016. Additional core rings will tie
    northeastern KY, southeastern KY, and Western KY in 2017. Radial (non-core)
    routes into each county will be interspersed throughout the project duration.

- **Project Cost**

	2016	2017	2018	Total
Inspection failure, Pole replacement - KU	$1,000k	$520k	$80k	$1,600k
Inspection failure, Pole replacement - LG&E	$200k	$180k	$20k	$400k
Reimbursable Company charges - KU	$1,000k	$440k	$160k	$1,600k
Reimbursable Company charges - LG&E	$200k	$160k	$40k	$400k
Reimbursement	-$1,200k	-$600k	-$200k	-$2,000k
Total Projected Cost	**$1,200k**	**$700k**	**$100k**	**$2,000k**

Economic Analysis and Risks

- **Bid Summary**

  - Both reimbursable and non-reimbursable Company make-ready work will be executed using Company personnel, or contracted workers under existing contracts, and will follow established Supply Chain procedures.
  - Bids for reimbursable labor related to inspection services and some design review services will be prepared following established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	2,160	1,260	180	-	3,600
2. Cost of Removal Proposed	240	140	20	-	400
3. Total Capital and Removal Proposed (1+2)	2,400	1,400	200	-	4,000
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(2,160)	(1,260)	(180)	-	(3,600)
8. Cost of Removal variance to BP (5-2)	(240)	(140)	(20)	-	(400)
9. Total Capital and Removal variance to BP (6-3)	(2,400)	(1,400)	(200)	-	(4,000)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-

This project was not included in the 2016 BP. The net capital expenditures, after reimbursement through from KentuckyWired, is $2.0M ($1.2M in 2016, $0.7M in 2017 and $0.1M in 2018). The 2016 incremental funding will be approved through the Corporate RAC process in January 2016.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$398
Contract Labor:	$2,410
Materials:	$312
Local Engineering:	$360
Burdens:	$457
Transportation:	$63
Contingency:	$ 0
Reimbursements:	($2,000)
Net Capital Expenditure:	$2,000

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	($64)	$56	$75	$177	$200	$2,808
Project ROE	-10.30%	3.60%	3.90%	9.50%	11.30%	10.20%

- **Assumptions**

  - The estimated number of pole failures (2.33%) will be consistent with the % reported to LKE as typical in scope and are reasonably accurate.
  - The estimated split in pole ownership is 65%/35% between LKE and Joint Use Partners.
  - The estimated costs to replace a pole is consistent with historic PITP pole replacement costs: $4,673 for LG&E and KU.

- **Environmental**

  There are no known environmental issues at this time.

- **Risks**

  - The cost to perform pole inspection failure remediation work will exceed the budget; this risk is mitigated by the Company placing a contractual ceiling ($2,000k) on the total investment to be made performing this work. Risk is shifted from financial risk to relationship/political risk should an excessive number of replacement poles be found.
  - Potential unavailability of quality contractor resources to perform inspection work. The variability in inspection work forecasted over different monthly periods by B&V (ranging from 1100 poles requiring make-ready in the peak month to fewer than 400

only 3 months later) suggests difficulties in keeping contractor inspection resources at a level that is consistent with quality assurance and reasonable workload.

- Safety and quality may be found lacking in the contractor/sub-contractor workforce employed by KentuckyWired requiring LKE to shutdown make-ready operations. To avert such a shutdown, KentuckyWired proactively monitors all work for compliance through their Quality Assurance Plan.
- Schedule KentuckyWired program dates are adjusted or delayed causing a change in budget amounts from year to year.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the identified KentuckyWired Fiber Make-Ready Project for KU and LG&E for $4,000k ($2,000k net of reimbursement) to support and accommodate the Commonwealth of Kentucky's fiber optic cable build-out project.

Investment Proposal for Investment Committee Meeting on: <u>June 28, 2017</u>

Project Name: <u>KU Portable Transformer</u>

Total Expenditures: <u>$3,390k (Including $442k of contingency)</u>

Project Number(s): <u>141885</u>

Business Unit/Line of Business: <u>Electric Distribution Operations</u>

Prepared/Presented By: <u>Jude Beyerle</u>

Executive Summary

Electric Distribution Operations (EDO) proposes to secure funding to purchase a portable transformer to support both planned and unplanned transformer outages in the KU Lexington and Danville substation service areas. This purchase will complete an overall strategy to enhance portable transformer capability at KU and LG&E. A portable was purchased for LG&E in 2014, and two KU units are on order as part of the N1DT program.

KU currently utilizes two portable transformers (7.5MVA and 30MVA) both normally stored in the Lexington area when not in use. Two additional KU portable transformers are on order, one will be stored in Pineville and one in Earlington, and will be primarily dedicated to supporting those respective areas as part of the N1DT strategy. The existing portable transformers are utilized frequently for planned maintenance outages, and are also called upon for rapid deployment in the event of a transformer failure or emergency maintenance. It is not uncommon to have both portables in service at the same time for maintenance outages and unavailable for transformer failures. An additional portable will benefit Substation Construction & Maintenance in providing more flexibility to support maintenance outages while still maintaining preparedness to address an unexpected transformer failure.

This proposed project provides for enhancements to the portable transformer plan for the KU service territory for maintenance, emergency and unplanned transformer outages. Specifically, this project includes the purchase of a 30 MVA 138x69:13.09kV LTC portable transformer and cable trailer. The cable trailer is purchased as a separate unit for easier transport and to lessen the overall length of the portable, allowing for more positioning and maneuvering flexibility in difficult to access stations.

The 2017 Business Plan (BP) included $2,252k in 2019 and $308k in 2020 for the purchase of a KU portable transformer. This project is now planned for 2017 and 2018. The 2017 funding was approved by the Corporate RAC in April. Funding for 2018 will be handled through the 2018 BP and the 2019/2020 amounts will be eliminated.

Background

The 7.5 MVA and 30 MVA KU portable transformers are not interchangeable due to MVA capacity limits and voltage ratings. In addition, they are not interchangeable with LG&E portables due to differences in standard winding configurations.

Between 2012 and 2016, the 7.5 MVA portable was in use an average of 150 days per year, or 41% of the time. During this same time period, the 30 MVA portable was in use, on average, 102 days per year or 28% of the time. For 46 days per year, or 13% of the time, both portables were in service at the same time.

An additional 30 MVA portable provides two primary benefits:

- An additional option for maintenance and construction outages. 74% of KU transformers are without full N1DT redundancy, so a portable install is often necessary to complete some routine and emergency maintenance and construction tasks, including transformer and load tap changer diagnostic maintenance and internal inspections and construction necessitating transformer clearance. A portable is a much lower cost option to deploy and set up than moving a spare unit into position by crane and completing temporary facilities.

- An additional option for emergency outages. As noted, the 30 MVA portable is historically in service 28% of the time, and there is no backup portable option. There have been occasions when the portable was removed from service at a maintenance location and moved to a new location to restore service for a failed transformer. In addition, due to limited options, past practice has often favored moving a spare into place for a failed transformer over using a portable. A large spare transformer, (base 12 MVA and greater) requires extensive logistics and coordination with contract partners to move into position, remove the failed transformer, set the new unit with a crane, install radiators, complete connections, commissioning and energization. A portable philosophy is consistent with more rapid customer restoration at those locations lacking N1DT redundancy.

There are 528 3-phase substation transformers in service on the KU system. This portable will be sized and configured to provide backup capability for 228 3-phase transformers, representing over 75% of system transformer capacity, including 136 base 12 MVA 69:12kV and larger units throughout all of KU; seven base 5 through 10 MVA 138:12kV units; and 85 Lexington and Danville area base 10 MVA 69kV:12kV units.

The remaining 300 3-phase units are 10 MVA and smaller, primarily in the Pineville or Western KY areas, and these will be supported by the existing 7.5MVA portable, and the two portable units now on order under a separate N1DT project.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

1. Recommendation: NPVRR: ($000s) $4,106k
   Purchase a new 30 MVA 138x69:13.09kV LTC portable transformer and a cable trailer. This portable will provide additional coverage during the average 102 days per year the

existing 30 MVA unit is in service for scheduled maintenance or emergency response. Although estimated total cost of this option is $3,390k.

2. Do Nothing: NPVRR: ($000s) $8,556k
   The Do Nothing option would result in a continued insufficient number of adequately sized portable transformers to consistently respond to planned maintenance and construction outages and emergency restoration related to in service substation transformer failures. Transformers are typically long life assets but KU's transformer fleet continues to grow older. The average age of KU Substation transformers is 40 years old, and the risk of transformer failure grows with increasing age.

   KU averages just over 3 transformer failures per year in the Lexington and Danville areas. Sixty percent (60%) of transformers in the Lexington and Danville areas cannot be fully backed up during high loading conditions.

   It is likely that one failure per year cannot be backed up, and a portable or spare install is necessary. This was experienced during failures in 2016 at Munfordville and E-town 3 substations.

   If a spare transformer is utilized instead of a portable transformer, which is a likely case 28% of the time, this assumes an average of four hours extra time to energize a spare compared to energizing a portable. This delay is primarily a result of prepping the spare unit for shipment and set up/teardown of the crane. A four hour or more improvement in service restoration, especially in extreme weather conditions (heat or cold), when customers typically need power the most, will have a positive impact on customer experience, the community, and also the Company's reputation. It should be noted that many substation transformer failures occur in non-storm situations (blue sky days) when customers are considerably less tolerant than they would be in storm situations. Assuming the failed unit is a base 12 MVA fully loaded near peak conditions:

   The calculation of the cost of unserved energy yields:
   (1.0 Failure) X (.28) X (22000 KVA) X (4 Hours) X ($17.20/kW-Hr) = $424k per year.

   Additional handling, crane and set up costs for a spare unit install for an emergency mobilization are in the order of $25,000:
   (1.0 Failure) X (.28) X ($25k) = $7k per year.

3. Next Best Alternative(s):   NPVRR: ($000s) N/A
   No other alternative to a portable transformer is seen as viable or cost effective. KU maintains adequate spares for emergency replacement of all size transformers of concern. However as noted, timeliness, mobility and installation cost concerns are not addressed with additional spares.

Project Description

- **Project Scope and Timeline**

8/4/2017	Purchase one (1) 30 MVA, 138x69:13.09 kV LTC portable transformer and one cable trailer
7/1/2018	Receive cable trailer
8/1/2018	Receive portable transformer

- **Project Cost**

  The estimated project cost for 2017-2018 is $3,390k; $3,000k to be incurred in 2017, and $390k in 2018.

  This project is estimated with 15% contingency ($442k), as the budgetary pricing estimates for the portable includes a +/- 15% variance.

Economic Analysis and Risks

- **Bid Summary**

  Competitive bids will be solicited from qualified portable manufacturers following standard Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	3,000	390	-	-	3,390
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	3,000	390	-	-	3,390
4. Capital Investment 2017 BP	-	-	2,252	308	2,560
5. Cost of Removal 2017 BP		-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	-	2,252	308	2,560
7. Capital Investment variance to BP (4-1)	(3,000)	(390)	2,252	308	(830)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(3,000)	(390)	2,252	308	(830)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2017 BP anticipated this project in 2019 and 2020. The project is now planned for 2017 and 2018. The Corporate RAC approved the 2017 amount in April. The 2018 BP will reflect the updated information for 2018-2020.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 9
Contract Labor:	$ 6
Materials:	$2,555
Transportation:	$ 2
Local Engineering:	$ 331
Burdens:	$ 45
Contingency:	$ 442
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 3,390

- **Assumptions**

Project costs are based upon budgetary price estimates provided by a qualified portable transformer supplier and cable trailer prices are adjusted from a 2016 purchase. The budgetary price estimates included a +/- 15% variance, thus a 15% contingency was chosen for this project.

KU's installed transformer base will continue to age and failure rates will continue at current rates or possibly increase, requiring an adequate portable transformer fleet to meet customer commitments. The useful life of a portable transformer typically exceeds 40 years.   The current average age of KU's transformers is 40 years old.

- **Environmental**

No environmental issues are known at this time.

- **Risks**

In the event of a transformer failure, the unavailability of a suitably sized portable unit could put thousands of customers at risk for a more severe extended outage, or delay response to maintenance issues that could evolve into a larger failure.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the KU Portable Transformer project for $3,390k to enhance our ability to respond to substation maintenance outages, and emergency outage response and substation restoration.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: August 28, 2013

Project Name:	Furniture for LGE Building Tenant Improvement
Total Expenditures:	$4,087K (Includes $533K for contingency)
Project Number:	Source Project #SVC141386 – Budgeted to 141389(KU) /141392(LGE)/ CAP141392
Business Unit/Line of Business:	Customer Services/Operating Services
Prepared/Presented By:	Lanny Thompson & Jerry Grant / Butch Cockerill

Executive Summary

Facility Services has previously received Investment Committee approval for the facility improvements identified under the new lease agreement in the amount of $7,521K. This project is referred to as the LG&E Building Tenant Improvement Project. This request is seeking approval to purchase the necessary furniture and ancillary products required in conjunction with the Tenant Improvement Project.

The Investment Committee is being asked to approve $4,087K for the purchase of office systems furniture and equipment that includes director level furniture, workstations for manager level employees and below, ancillary items, conference room tables and chairs, file cabinets, and appliances. The 2014 proposed Business Plan (BP) includes $4,202K for 2014-2017 for this project. A contract proposal is also being requested that identifies Kimball Office Products as the proposed supplier that will be used for the company's standard workstations for managers and below.

The only alternative to this project is to reduce the scope of the LG&E Building Tenant Improvement project and only purchase furniture for floors that don't have existing furniture and appliances. This alternative does not address the risks identified in this document.

Background

The majority of the furniture in this facility is the original furniture which is over 20 years old. A primary feature of systems furniture is its flexibility and ease of which it can be assembled and disassembled and reconfigured to meet the changing needs of the clients. Over the life of the existing furniture, Facility Services has assembled and disassembled the furniture numerous times. As such, the furniture has reached is useful and safe life expectancy. Additionally, over the years, we have purchased various types of work stations and various vintages of the same workstations. Thus, it has become increasingly difficult to acquire parts and materials for our existing workstations and the powered panels for some types of the workstations are no longer available. The powered panels provide the electrical wiring for a workstation. Therefore, it is

becoming increasingly difficult to repair existing workstations and find sufficient components to **Although** create additional workstations. Without some corrective action, we will be in a position of replacing existing workstations with a different type which may not safely connect to existing workstations and be of a different size or color; creating aesthetic issues.

- **Other Alternatives Considered**
  - o Reduce the scope of the LG&E Building Tenant Improvement project and only purchase items for floors with no systems furniture existing (3ʳᵈ Floor Furnishings cost only--$434K). However, this alternative does not address all the risks identified above.

Project Description

At the present time the rate of vacant workstations per floor is <10%; impacting departmental expansion due to lack of contiguous space. To effectively optimize existing floor space, workstation space standards must be revised. Many enhancements in office space design along with technological improvements allow revisions to workspace standards without impacting the occupant's effective use of their office space. New workstations will also address escalating issues with existing workstations purchased when the building was initially occupied.

By revising workstations & office standards, space will be maximized to address long term space requirements. Concurrently, this will address fragmented business units; requiring the purchase of modular workstations and the creation of new team space. In addition, the use of rotary filing will allow for compression space dedicated to filing.

The projected timeline and schedule for purchase of furniture and ancillary products in conjunction with the Tenant Improvement Project is as follows:

- o 2013 – Floors 6 and 14
- o 2014 – Floors 3 and 7
- o 2015 – Floors 4, 5, and 8
- o 2016 – Floors 9, 10, and 11
- o 2017 – Floors 12, 15, and 16

Economic Analysis and Risks

- **Bid Summary**

The Company has identified several potential facility projects over the next five years that will require large quantities of workstations and ancillary furniture. As a result of the large volume of furniture that will be needed should these projects move forward and the desire to establish furniture standards across the Company, a Request for Proposal (RFP) was issued. As a result of the RFP process, ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮ was selected as the recommended vendor. Currently, this contract is being presented to the Investment Committee for approval this month. The table below shows the total costs of the bid for the two short listed companies. The pricing obtained from MBI was used to project the estimated costs for this investment proposal.

Total Costs ($000s)	▮	▮

The total number of workstations and director furniture to be replaced by year was determined based upon the timeline and schedule previously discussed. A RFP to establish a vendor for director furniture will be issued soon. The table below shows the proposed cost per year.

$000s	
2013	$ 413
2014	$ 767
2015	$ 1,249
2016	$ 1,249
2017	$ 409

The total cost to purchase all the projected furniture needs of the project has been estimated at $4,087K, including a 15% contingency of $533K. A higher than normal contingency percentage is included due to the likelihood of changes to either the above schedule or quantity of furniture needs. The total volume of furniture needs, especially the number of workstations, on each floor varies greatly and any change in the approved construction and renovation schedule, year over year, will affect the total spend and volume discount rate for that year.

- **Budget Comparison and Financial Summary**

Contract Expenses ($k)	2013	2014	2015	2016	2017	Total
LG&E Bldg. Project Proposed Systems Furniture Budget Incl. – Installation	$290	$535	$883	$883	$289	$2,880
Removal Costs	$19	$32	$53	$53	$17	$174
Director Level Furniture	$50	$50	$100	$100	$0	$300
Appliances	$0	$50	$50	$50	$50	$200
Sub Total All Furniture and Appliances	$359	$667	$1,086	$1,086	$356	$3,554
Contingency	$54	$100	$163	$163	$53	$533
Total with Contingency	**$413**	**$767**	**$1,249**	**$1,249**	**$409**	**$4,087**
Facility Services[1] Included in 2014 BP	$0	$1,050	$1,050	$1,050	$1,052	$4,202
Variance to BP	($413)	$283	($199)	($199)	$643	$115
Amt. Requesting Approval	**$413**	**$767**	**$1,249**	**$1,249**	**$409**	**$4,087**

[1]This is based on the current proposed 2014-18 BP.

The projected funding by year is determined based upon the project timeline and schedule previously discussed. Funds requested in this Investment Proposal will be drawn upon as each floor plan is approved.

Financial Detail by Year ($000s)	2013	2014	2015	Post 2015	Total
1. Capital Investment Proposed	394	735	1,196	1,588	3,913
2. Cost of Removal Proposed	19	32	53	70	174
3. Total Capital and Removal Proposed (1+2)	413	767	1,249	1,658	4,087
4. Capital Investment 2013 BP	-	-	-	-	-
5. Cost of Removal 2013 BP	-	-	-	-	-
6. Total Capital and Removal 2013 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(394)	(735)	(1,196)	(1,588)	(3,913)
8. Cost of Removal variance to BP (5-2)	(19)	(32)	(53)	(70)	(174)
9. Total Capital and Removal variance to BP (6-3)	(413)	(767)	(1,249)	(1,658)	(4,087)
10. Project O&M Proposed	-	-	-	-	-
11. Total Project Proposed (3+10)	413	767	1,249	1,658	4,087

Financial Summary ($000s):
Discount Rate: 6.5%
Capital Breakdown:
  Labor: $ 0
  Contract Labor: $ 464
  Materials: $3,090
  Local Engineering: $ 0
  Burdens: $ 0
  Contingency: $ 533
  Reimbursements: $ 0
  Net Capital Expenditure $4,087

Project Presented and alternatives:

Financial Analysis - Project Summary ($000)	Project Proposed	Alternative 1 (Next Best)*	Do Nothing (Not Applicable)
NPVRR	$4,762	$610	$0
NPV Cash Flows	$($331)	($26)	$0
ROE - 2013	(7.8%)	(7.8%)	0.0%
ROE - 2014	(3.9%)	(0.4%)	0.0%
ROE - 2015	(2.0%)	10.3%	0.0%
ROE - 2016	(0.4%)	10.3%	0.0%
ROE - 2017	4.7%	10.3%	0.0%
ROE - Life of Project	9.5%	10.3%	0.0%

    * This alternative does not address all the risks identified above. This project is not economically driven. The necessity to place furniture in spaces acquired at the building and replace existing furniture that is aging is the driver for the funding requested.

- **Assumptions**
  - Contract Proposal recommending ███ will be approved.
  - No changes to timeline and schedule as outlined above in the Project Description Section.

- **Environmental**
  - Not Applicable

- **Risks**
  - There is no furniture for the additional floor (3rd floor) that was just acquired in the building lease.
  - Without this project, it would impact the ability to establish work space for departmental continuity and establish space for future project teams.
  - Due to age of assets and different furniture types in use today, we are unable to obtain component parts to repair existing workstations or components needed to create additional workstations.
  - Without replacing existing furniture, we will likely need to purchase workstations on an as needed basis which may or may not properly adjoin existing workstations and will have a different appearance than existing units.
  - The current occupancy levels/space design provides very little, if any, space for departmental expansion.

Conclusions and Recommendation

It is recommended that the Investment Committee approve $4,087K of funding to purchase the necessary furnishings in order to support the completion of the Tenant Improvement Project.

Arbough

Investment Proposal for Investment Committee Meeting on: <u>November 28, 2018</u>

Project Name: <u>LG&E Center Tenant Improvement Furniture</u>

Total Approved Expenditures: <u>$4,087k</u> (Approved on 08/28/2013)

Total Revised Expenditures: <u>$4,915k</u>

Project Number(s): <u>141392, 141389, and LKS142731</u>

Business Unit/Line of Business: <u>Customer Services/Operating Services</u>

Prepared/Presented By: <u>Cheryl Bruner/Zac Conley</u>

Reason for Revision

In August 2013, the Investment Committee approved the LG&E Center Tenant Improvement Furniture project for $4,087k. This proposal is requesting approval for the revised amount of $4,915k. The original estimate used an average cost of $300k per floor for twelve floors, plus contingency. Included in this estimate was: office systems furniture and equipment, Director furniture, conference room tables, chairs, file cabinets, artwork, A/V equipment, appliances, and all ancillary equipment, such as white boards and trash receptacles. Not included originally, but purchased under this Investment Proposal, were the fitness center equipment when the second floor fitness center was constructed, and replacement/additional Officer furniture. Additionally, nine floors have exceeded the original estimate, the two remaining floors will exceed the original estimate, and two other floors were added to the original scope. Some floors required more furniture based on the final design for number of employees. The 16th floor requires an additional $100k worth of filing cabinets.

Financial Summary ($000s):	Approved	Revised
Discount Rate:	6.5%	6.59%
Capital Breakdown:		
Labor:	$ 0	$ 0
Contract Labor:	$ 464	$ 150
Materials:	$ 3,090	$ 4,653
Local Engineering:	$ 0	$ 34
Contingency:	$ 533	$ 78
Reimbursements:	($ 0)	($ 0)
Net Capital Expenditure:	$ 4,087	$ 4,915
NPVRR:	$ 4,762	$ 5,042

The NPVRRs represent the cost to ratepayers in 2013 dollars, because the project began Although 2013.

Financial Detail by Year - Capital ($000s)	Pre-2018	2018	2019	Post 2019	Total
1. Capital Investment Proposed	3,222	853	840		4,915
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	3,222	853	840	-	4,915
4. Capital Investment 2019 BP	3,222	695	342		4,259
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	3,222	695	342	-	4,259
7. Capital Investment variance to BP (4-1)	-	(158)	(498)	-	(656)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(158)	(498)	-	(656)

Financial Detail by Year - O&M ($000s)	Pre-2018	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

The increases for 2018 have been approved through the Corporate RAC process. The increases for 2019 from the 2019 Business Plan will be covered by other Facilities projects within the Customer Service RAC. See attachment for comparison to original proposal.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the furniture for the LG&E Building Tenant Improvements project for $4,915k to complete renovations at the LG&E Building.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

($000s)	ORIGINAL PROPOSAL						REVISED PROPOSAL								Variance
	2013	2014	2015	2016	2017	Total	2013	2014	2015	2016	2017	2018	2019	Total	
LG&E Bldg. Project Systems Furniture Incl. – Installation	$290	$535	$883	$883	$289	$2,880	$503	$717	$443	$592	$348	$778	$688	$4,069	($1,189)
Removal Costs	$19	$32	$53	$53	$17	$174	$0	$0	$0	$0	$0	$0	$0	$0	$174
Director Level Furniture	$50	$50	$100	$100	$0	$300	$9	$101	$194	$158	$58	$50	$50	$620	($320)
Appliances	$0	$50	$50	$50	$50	$200	$20	$24	$13	$25	$16	$25	$25	$148	$52
Sub Total All Furniture and Appliances	$359	$667	$1,086	$1,086	$356	$3,554	$532	$842	$650	$775	$422	$853	$763	$4,837	($1,283)
Contingency	$54	$100	$163	$163	$53	$533	$0	$0	$0	$0	$0	$0	$78	$78	$455
Total with Contingency	**$413**	**$767**	**$1,249**	**$1,249**	**$409**	**$4,087**	**$532**	**$842**	**$650**	**$775**	**$422**	**$853**	**$841**	**$4,915**	($828)
Facility Services Included in BP	$0	$1,050	$1,050	$1,050	$1,052	$4,202	$532	$842	$650	$775	$422	$853	$343	$4,417	($215)
Variance to BP	($413)	$283	($199)	($199)	$643	$115	$0	$0	$0	$0	$0	$0	($498)	**($498)**	$613
Amt. Requesting Approval	**$413**	**$767**	**$1,249**	**$1,249**	**$409**	**$4,087**	**$532**	**$842**	**$650**	**$775**	**$422**	**$853**	**$841**	**$4,915**	($828)

Investment Proposal for Investment Committee Meeting on: <u>November 28, 2018</u>

ProjectProject Name: <u>Lime Kiln Substation</u>

Total Expenditures: <u>$11,477k (includes $1,043k of contingency)</u>

Project Number(s): <u>Distribution Substations 148885, Distribution Lines 148884, Transmission Lines 134238</u>

Business Unit/Line of Business: <u>Electric Distribution Operations</u>

Prepared/Presented By: <u>Zachary Allen-Kelly/Dan Hawk</u>

Executive Summary

LG&E Electric Distribution Operations (EDO) seeks funding authority of $11,477k to enable construction of a new distribution substation on Brownsboro Road near Lime Kiln Lane (see Attachment 1). Additional system capacity is needed in the nearby service area to meet load requirements for the new ███████████████████████████, which is scheduled to be under construction starting in 2019. Requested funding will provide for construction of a single unit 44.8kVA 69-12kV substation and 69kV ring bus, and necessary improvements to associated distribution and transmission line facilities.

Construction on the proposed substation will be completed between January 2019 and December 2020. Approximately 3,600 customers currently served out of the Taylor and Harrods Creek Substations will be connected to the new substation, once it is placed into service. Once completed, the new substation will enable EDO to remove all three existing Taylor substation transformers from its Distribution Substation Transformer Contingency Program (N1DT).

EDO allocated $10,492k (2019 - $4,578k, 2020 - $5,914) in its 2019 Business Plan for the proposed substation, based on preliminary design estimates. EDO plans to account for the increased project funding requirements in its 2020 Business Plan.

Background

Taylor Substation contains three 28 MVA transformers. The three transformers all have between 18 and 22.5 MVA of load on them in the most recent 2019 forecast, and all are on EDO's N1DT risk list. The site of the proposed new ██████████ is located roughly one mile from Taylor substation, on the opposite side of Interstate 264. There are two existing Taylor circuits that cross I-264 at US-42 and feed approximately 10 MVA of existing load. The ██████████ is expected to go online in 2022 and reach full load by 2024. The ███ has projected their load at approximately 6 MVA under normal conditions, with loads up to 10 MVA in an emergency situation. Distribution Planning has determined that the new ███load is unable to be served out

of Taylor substation as currently configured due to both distribution circuit and substation **Arbough** transformer load constraints. The ▇▇▇▇▇▇ requires a second, redundant electric feed from a separate distribution substation source as their main feed. The proposed new Lime Kiln Substation will take approximately 10 MVA of load off Taylor substation, freeing up enough circuit and transformer capacity to comfortably serve the new ▇▇▇▇▇▇ out of Taylor. Though not a primary driver of the project, the new station will also remove all three Taylor Transformers from the N1DT "risk" list as well as provide a second source to the hospital to meet their redundant capacity requirement. The distribution work associated with this redundant feed out of Lime Kiln would be paid for by the customer as part of their redundant capacity request.

- **Alternatives Considered**

1. Recommended Option: NPVRR ($000): $13,076
   The recommended option is to build a new distribution substation along US-42, including a new standard 44.8 MVA transformer, steel, and breakers (plus associated transmission and distribution line improvements). This option is expected to avoid expected overload at Taylor substation and distribution circuits from the proposed ▇▇▇▇▇▇.

2. Do Nothing Option: NPVRR ($000): N/A
   LG&E has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating limits for distribution substation power transformers and distribution line conductors, and this practice reduces the life of these assets and elevates the risk of failure of a high value, critical asset.

3. Alternative 1:   NPVRR: ($000s) $14,327
   This option considers the upgrade of two of the existing Taylor transformers to 44.8 MVA and the installation of a new distribution circuit along US-42 to serve the ▇▇▇▇▇▇. Due to space constraints on the existing pole route, this circuit would need to be entirely underground and would require a long bore under the Watterson Expressway. This option meets capacity needs but is more expensive and would not provide the reliability improvements gained from a separate distribution source and reduced circuit exposure. The estimated capital cost of this alternative is $12,667k.

Project Description
Project Scope
- Substation project #148885: estimated cost $7,909k ($3,000k-2019; $4,909k-2020).
  - Install a new 44.8 MVA, 69-12 kV transformer, 69kV ring bus, breakers, steel, control house, and associated equipment in the new Lime Kiln substation.
- Distribution project #148884: estimated cost $2,674k ($1,501k-2019; $1,173k-2020).
  - Distribution work associated with the new Lime Kiln substation. Install approximately 12,867' of 795 AAC OH conductor, 5,075' of 1000MCM UG conductor, along with additional tie switches for 5 new distribution circuits. Approximately 2,100' of new conduit with manholes will need to be installed. Contingency is included to cover the uncertainty of easement costs and rock removal.

- Transmission project #134238: estimated cost $894k ($79k-2019; $815k-2020). **Arbough**
  - Install poles and conductor as needed to route the 69 kV transmission line into the Lime Kiln substation; perform other temporary work as necessary to accommodate construction.
  - A Network Integration Transmission Service (NITS) will need to be submitted for the new Lime Kiln substation.

- **Project Timeline**
  - December, 2018: Open projects.
  - January-March, 2019: Perform substation and transmission engineering design related tasks; order major equipment.
  - April-June, 2019: Perform distribution engineering design related tasks for planned 2019 work; order materials.
  - July-December, 2019: Complete distribution conductor improvements for planned 2019 work; receive major substation and transmission equipment.
  - January-April, 2020: Perform substation site preparation and foundation work; perform distribution engineering design related tasks for planned 2020 work; order materials.
  - May-August, 2020: Progress on transmission foundations and pole installation; progress on distribution conductor improvements for planned 2018 work.
  - September-November, 2020: Install substation structures and equipment; progress on distribution conductor improvements.
  - December, 2020: Complete remainder of substation, transmission, and distribution improvements; commission substation.

- **Project Cost**
  - The total estimated cost of the project is $11,477k. The substation and transmission line cost estimates are consistent with the "Conceptual Level 1" engineering design designation. The distribution cost estimate is consistent with the 'Preliminary" engineering design designation and is based on field experience from similar projects. There is an estimated 10% of contingency ($1,043k) incorporated into the project cost estimates. More detailed engineering designs will be conducted after project approval.

Economic Analysis and Risks

- **Bid Summary**
  - The substation transformer and steel package as well as transmission poles will be bid using established Supply Chain procedures.
  - For other requirements, Substation Construction and Maintenance (SC&M), Distribution Operations, and Transmission Lines will use existing material and labor contracts and follow established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Athrsough 2021	Total
1. Capital Investment Proposed	4,285	6,730			11,015
2. Cost of Removal Proposed	295	167			462
3. Total Capital and Removal Proposed (1+2)	4,580	6,897	-	-	11,477
4. Capital Investment 2019 BP	4,578	5,745			10,323
5. Cost of Removal 2019 BP	-	169			169
6. Total Capital and Removal 2019 BP (4+5)	4,578	5,914	-	-	10,492
7. Capital Investment variance to BP (4-1)	293	(985)	-	-	(692)
8. Cost of Removal variance to BP (5-2)	(295)	2	-	-	(293)
9. Total Capital and Removal variance to BP (6-3)	(2)	(983)	-	-	(985)

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was identified and funded in the 2019 Business Plan at the following levels: Substation project #148885 ($2,999k-2019; $4,100k-2020); Distribution project #148884 ($1,499k-2019; $1,000k-2020); Transmission project #134238 ($79k-2019; $815k-2020). The $982k budget shortfall in 2020 will be addressed in the 2020 Business Plan.

Financial Summary ($000s):

Discount Rate: 6.59%
Capital Breakdown:
Labor: $ 278
Contract Labor: $ 4,600
Materials: $ 4,064
Local Engineering: $ 787
Burdens: $ 657
Contingency: $ 1,043
Transportation: $ 48
Reimbursements: ($ 0)
Net Capital Expenditure: $11,477

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution improvements are consistent with similar past projects.

- **Environmental**
  - There are no known environmental issues at this time.

- **Risks**
  - The cost of the distribution portion of the project could escalate because a detailed engineering design was not conducted prior to the preparation of these cost estimates. Costs are based on similar completed work for other projects of similar scope and size.
  - Failure to complete this project in a reasonable time frame could negatively impact the company's ability to serve new loads associated with the ████. Insufficient infrastructure could result in outages and/or failure of the existing substation transformer and distribution circuits.
  - At the time of the writing of this IP, the ██ has yet to sign a contract for their projected load, so there is a risk the new hospital project could be delayed or canceled. In order to mitigate this risk, early 2019 work on the project will be limited to design work and equipment purchases that can be reassigned to other projects.

Conclusions and Recommendation   **Arbough**

Electric Distribution recommends that the Investment Committee approve the Lime Kiln Distribution Substation project for $11,477k to provide adequate distribution substation capacity for existing and future loads in Louisville, KY.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: December 20, 2017

Project Name: Lock Out/Tag Out (LOTO) Software Replacement Project

Total Expenditures: $2,875k   (Including 259k of contingency)

Project Number(s): IT0329B

Business Unit/Line of Business: Power Production

Prepared/Presented By: Paul Wright, Toby Wright, Sandi O'Banion

Executive Summary

Implemented in March 2015, the NiSoft e3 application's purpose was to augment the Company's Lock Out/Tag Out (LOTO) policy by providing an electronic method for managing Clearances and associated equipment HOLDs from creation and isolation through release and re-energization. The LOTO application is vital to Generation personnel for accurately managing Clearances and associated equipment HOLDs and is considered the system of record for Clearances and equipment HOLDs. For this reason, information regarding Clearances and HOLDs must be 100% accurate. Any inaccuracy results in a potential unsafe situation that could cause a safety incident.

The LKE production version of LOTO e3 was implemented on a custom version of NiSoft's e3 core software due to the need to make immediate code modifications to address critical defects discovered prior to and during the implementation. When using a Hand Written (Paper) Hold Card system as well as the first versions of Software for the LOTO systems, the owner would hang a separate tag on each device that was to identify that this device could not be moved or activated while that tag was in place, for each person that requested for it to be tagged. This ends up with multiple tags being placed on Switches, Breakers and Valves. At times there could be up to 100 tags placed on these individual devices. Our company as well as the industry sees that having these multiple tags placed in the field, increased the possibility and exposure to mistakes being made by misplacement or incorrect removal of tags on or from the proper device. Industry came up with the approach that the Software of our LOTO systems could manage the multiple names of people obtaining clearances on these devices and only hanging one tag on the device that is related to the clearance that multiple people can electronically sign-on to, to hold the Clearance. This is seen and sought after by our company as the next step in making our LOTO system a safer and more manageable program to use. Additionally, since LKE was the first client to utilize Hold Card Sharing, the software contained numerous defects, and work-arounds and the use of card sharing was discontinued. LKE made the decision to proceed with the implementation using a point-in-time copy of the e3 software with known defects and work-arounds, with the understanding that Hold Card Sharing would be re-engineered and re-implemented after go-live under the NiSoft e3 maintenance agreement. This approach allowed the implementation to proceed without further delays. Technical issues with NiSoft's e3, manual work arounds, and instability drives the urgency of this project.   After the implementation, the team attempted to work with NiSoft to improve quality and service. A card sharing rewrite project was planned and estimated to correct all the issues with e3 at a cost of $1,623k (business labor not included) over 19 months. The rewrite project was put on hold and a new Request for Proposal (RFP) was submitted for a completely new LOTO software to replace e3 once NiSoft stated e3 was a document management application and not a system of record which could cause misinformation for real-time clearances.

As a result of the thorough vendor evaluation process, ███████████████████████ ██████████████ is the recommended LOTO software platform for LGE/KU's long-term LOTO solution. This project will procure and implement a new LOTO system across the fleet with card sharing functionality. This scope will include the following sites: Paddy's Run, Mill Creek, Ghent, Cane Run 7, Trimble County and EW Brown, along with the hydro-units at Ohio Falls and Dix Dam. This scope will exclude Haefling and the retired assets at Cane Run and Green River.

This proposal seeks approval of $2,875k in capital expenditures (includes $259k of contingency) to procure and implement a new LOTO application. This project has a total of $2,400k included in the proposed 2018 BP ($2,000k in 2018 and $400k in 2019). An additional $475k requested for 2019 will be addressed as part of the 2019 BP planning process. There was $400k in 2017 that was provided back to the Corporate RAC.

Background

The Lock Out/Tag Out (LOTO) management system is a vital component in managing clearances for power plant equipment. Safety is the cornerstone of the LG&E/KU value system. The system manages the process in accordance with the company's comprehensive Lockout/TagOut policy. The generating station's 3,500 users have utilized the NiSoft e3 application for the last three years. Over 100,000 clearances per year are processed utilizing a database of 142,000 devices. These clearances isolate equipment to keep employees safe from energized devices within the generating plants. The software tracks the process from initial request to the final stage of removing the tags off the devices.

Five years ago when NiSoft's e3 product was selected, tasked based card sharing functionality required by LKE was not available in the Lock Out/Tag Out products that were on the market. In order to meet the card sharing requirements, NiSoft had a significant development effort to provide all the card sharing functionality. In addition, e3 was NiSoft's first web-based product and no one was using e3 with card sharing. After an extensive design, customizations, and enhancements of the card sharing functionality and implementation, significant issues arose such that the card sharing functionality used within the company was discontinued due to safety concerns.

The enhancements to e3 were written and executed outside the core product so that patches could be applied without having to release new versions of the core application. Unfortunately, this design created integrity issues within the system. Currently two sets of database tables are maintained, one which is a real-time updated database and one which is used to send information to the screens. The real time data in the database and the data displayed on the screen could get out of sync in the event that transactions failed to complete. Workarounds were created and required to maintain the data integrity, keep the data in sync and displayed properly. Due to all the issues and daily manual work arounds that exist, LKE started a new project to replace NiSoft's e3. Manual checks are currently conducted by the administrative authority to review every clearance and every device to ensure the card counts match as clearances are released and locks are not found in the system on devices as clearances are created. The current system would need to be replaced within a couple of years due to software upgrades and patches cannot be applied to NiSoft's e3. Patches and new builds from NiSoft created more issues with the product than fixes which impacts the support we can receive from NiSoft. NiSoft has since stated e3 is not a real time system of record, the product is a document control system. LKE has lost confidence in e3 and the ability to accurately track clearances and has prompted the need for a new project.

The following team of LG&E/KU stakeholders was assembled for the project:
- Production Managers and other operational staff members
- Manager, Fleet Operational Performance and Reliability

- Information Technology

This group researched LOTO vendors on the market today and prepared requirements for a new RFP. Requirements were gathered from the previous project which included the lessons learned at the end of the project, which took into consideration the issues that were encountered in production. The core team thoroughly reviewed the updated requirements to ensure consistency and clarity of the requirements across the business. The team used this opportunity to improve the existing requirements and LOTO processes with a concentration on card sharing.

The team thoroughly evaluated the top fifteen recommended vendor applications with card sharing functionality with real time updates. Preliminary demos were conducted and vendors that could not demonstrate card sharing were eliminated from consideration. The RFP was ultimately submitted to five vendors. The team reviewed the RFP responses and eliminated some of the companies due to the limited number of support staff and some due to technical concerns. ▇▇▇▇▇▇ and ▇▇▇▇▇▇ came out on top based on the RFP responses. On-site demos were conducted and extensive question and answer sessions were held. Second demos were held to further clarify outstanding concerns, as well as conducting detailed project plan reviews, timeline, and cost discussions. Vendors were asked to identify any functionality listed in our requirements that were either configuration or customizations and resubmit adjusted costs based on what was learned during our on-site discussions. The team evaluated the final responses and scored the vendors, ▇▇ and ▇▇. The scoring was evenly split between the two vendors and the final decision was ultimately based on cost.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $3,454
  2. Alternative #1: ▇▇▇▇▇   NPVRR: ($000s) $5,574
     - Although there were some O & M savings associated with the ▇▇▇▇▇ option, the higher capital cost of $6,678k could not be offset. There was no significant benefit between the solutions to justify the significant capital cost.
     Alternative #2: Do Nothing   NPVRR: ($000s) n/a
     - Staying with NiSoft and doing nothing is not a viable long-term option for the following reasons:
       - NiSoft has stated that e3 is a document management system and not a real time system of record.
       - A major upgrade of NiSoft e3 would be required and the card sharing functionality would have to be rewritten as part of any NiSoft e3 solution.
       - The software has major design flaws in these areas: Failover Recoverability, Share Counts, and Daily Clearance Reports are not accurate. In some cases, the system gets locked up.
       - Daily Manual Workarounds are required to monitor the application. There are two LKE-created reports that are run daily to ensure the system is working properly.
       - Plants are required to limit the amount of devices on a clearance because the system can't handle more than 50 devices. It is common that the business requires more than 50 devices. Once this situation causes failure, manual intervention is required to release the additional devices from the clearance. To avoid the situation, several clearances have to be created with smaller device counts.
       - NiSoft software updates tend to break other areas of the code.

Project Description

- **Project Scope and Timeline**

The ▮▮▮▮▮▮▮ software system will be implemented to support the card sharing functionality process for the fleet. Corporate Purchasing verified the size, age, and solvency of ▮▮▮. Due diligence was also performed to confirm the installation base of the product, customer referrals, and technical support infrastructure. The system will be implemented in phases across the fleet, starting with E.W. Brown. This will help ensure there are sufficient implementation resources and the lessons learned from the installation are applied to the next location.

This scope will include the following sites: Paddy's Run, Mill Creek, Ghent, Cane Run 7, Trimble County and EW Brown, along with the hydro-units at Ohio Falls and Dix Dam. This scope will exclude Haefling and the retired assets at Cane Run and Green River.

The primary objectives are:
- Implement the ▮▮▮▮▮▮▮ software system to support the LOTO process across the generating fleet with ZERO safety incidents attributable to a defect in the new process or system
- Implement the capability of card sharing into the core product
- Implement ▮▮▮▮▮▮ without any major defects in the ▮▮▮▮ product

The secondary objectives are:
- Explore the implementation of an interface to ▮▮▮▮
- Improved end-user reporting
- Implement the ▮▮▮▮▮▮ mobile application with barcoding capabilities

Major Milestones

2017 -	December	IP Presentation to Investment Committee and upon approval, Contract Award
2018 -	January	Kickoff
2018 -	May	System Design Complete
2018 -	November	System Customization & Configuration Complete
2019 -	March	User Acceptance Test (UAT) Complete
2019 -	March	Brown Training and Rollout Complete
2019 -	April	Ghent and Cane Run Unit 7 Training & Rollout Complete
2019 -	May	Mill Creek and Trimble County Training & Rollout Complete

- **Project Cost**

  The Lock Out Tag Out system being requested has a direct impact on safety, potential for serious injuries and threat to human life. This proposal seeks the approval for a total of $2,875k in capital expenditures. This includes a $259k contingency. This cost will cover procurement of the LOTO software, configurations and enhancements of the software, testing, training of the core team, and end-user training & implementation at each station across the fleet. The contract with ▮▮▮▮ is a fixed bid.

Economic Analysis and Risks

- **Bid Summary**

Four vendors submitted bids with the team eliminating two of them because they did not meet minimum support requirements. Evaluation of the remaining two are:

	Max Score		...ugh
Price of Software	10		
Price of On-Going Software	10		
Price of Professional Services	5		
Solution Requirements	45		
Proposed Work Plan/Implementation	5		
Training	5		
Experience and Stability	10		
Incident Support/Upgrades	10		
Total	100		
Total Capital Cost ($000s)			

Budget Comparison and Financial Summary

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	1,957	918			2,875
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	1,957	918	-	-	2,875
4. Capital Investment 2018 BP	2,000	400			2,400
5. Cost of Removal 2018 BP					-
6. Total Capital and Removal 2018 BP (4+5)	2,000	400	-	-	2,400
7. Capital Investment variance to BP (4-1)	43	(518)	-	-	(475)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	43	(518)	-	-	(475)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	109	109	109	218	545
2. Project O&M 2018 BP			79	167	246
3. Total Project O&M variance to BP (2-1)	(109)	(109)	(30)	(51)	(299)

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 1,446
Contract Labor:	$ 566
Materials:	$ 573
Property Tax:	$ 31
Burdens:	$ 0
Contingency:	$ 259
Reimbursements:	($ 0)
Net Capital Expenditure:	$2,875

- **Assumptions** Arbough
  - o Unit outage schedules are dynamic and thus the implementation schedule will remain flexible, while still holding a completion target of June, 2019.
  - o The economic useful life of the system is a minimum of ten years.
  - o The new system is scalable and can be adapted to our changing company needs.
  - o Plant resources will be utilized to develop new or additional data for the system.
  - o The project will utilize a train-the-trainer approach. The project team will develop a schedule and plants will support the process of training affected employees and contractors.
  - o Train-the-trainer and project team training will be charged to the team members' regular O&M charge numbers.
  - o Existing network bandwidth to/from the plants is sufficient.
  - o Super Users will be identified and brought in to practice the training and review the data migration during the project.
  - o Historical clearances will be migrated.
  - o The mobile application will be available only internally.
  - o Active clearances will not be migrated in the system. The active clearances will be used on go live for training and will be entered manually.

- **Risks**
  - o This project has a long timeline and thus, team members, financial resources, and business priorities can change. **Mitigation:** Plants will provide one to two representatives to the core team to allow for flexibility in scheduling and redundancy of representation. IT will follow standard processes and maintain system documentation to allow transition of resources. If financial resources or business priorities change, the impact to the project will be assessed at that time.
  - o While changing the tool used for LOTO, each plant will be implementing a process that has new elements; some more than others. This increases the risk of human error to the safety system process. **Mitigation:**
    - ▪ Training is the key component. The Core Team will receive extensive training in the product and has worked together to define the process. The Core Team will guide delivery of train-the-trainer classes, the material and content developed for end-user training, and delivery of that training to the end users.
    - ▪ Each plant will select key individuals to receive the training early and to assist with final preparations at each site prior to launch to increase their knowledge and provide "go to" personnel on each shift.
    - ▪ Additional IT and vendor resources will be available on-site for immediate response to any issues that may arise during first implementations.
    - ▪ The team will define and deliver communications to plant personnel tailored to their needs and using regular communications channels.
  - o During the conversion from one system to another, there will be a period of possible confusion as tags from the new system are hung and tags from the old one have not been removed yet. **Mitigation:**
    - ▪ Units not in an outage or predetermined areas of the plant will be converted first, minimizing the number of individuals impacted.
    - ▪ Conversion will take place over a weekend to alleviate the amount of confusion. IT will provide onsite support during the cutover weekend as needed.
    - ▪ Advanced and on-going communication to all plant personnel via existing channels will be developed and delivered.
    - ▪ A LOTO deviation will be requested at each plant for the duration of the launch that requires Plant General Manager approval and support from all levels of the plant.

Conclusions and Recommendation Arbough

It is recommended that the Investment Committee approve the Lockout/Tagout (LOTO) System project for $2,875k to provide clearance accuracy and card sharing functionality within the application.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: <u>March 29, 2017</u>

Project Name: <u>Mill Creek Limestone Unloading Barge Replacement</u>

Total Expenditures: <u>$2,700k (including $240k in contingency)</u>

Project Number(s): <u>139717</u>

Business Unit/Line of Business: <u>Power Generation / Mill Creek Station</u>

Prepared/Presented By: <u>Jason Thompson / Joe Didelot</u>

Executive Summary

The Mill Creek limestone unloading barge was commissioned in 2000 and serves a vital role in the limestone handling process at the plant. Limestone is transferred from delivery barges via an excavator that rests on the deck of the unloading barge. The unloaded limestone is utilized in the wet flue-gas desulfurization (WFGD) systems. Due to limited space, only seven days of limestone inventory is maintained on site, making the barge a critical asset at the plant. The structural members, hull and decking surfaces have reached the end of their useful life. The risk of derates and outages increases dramatically with the probability of major barge repairs.

The scope of this project includes the purchase and installation of a new limestone unloading barge. This project is included in the 2017BP with $500k in 2017 for barge purchase milestones and $2,200k in 2018 for completion of the purchase and installation.

It is recommended that the Investment Committee approve the Mill Creek limestone unloading barge replacement project for $2,700k to avoid the risk of outages should the barge experience a catastrophic failure.

Background

The limestone unloading barge was designed in 1999 and has been in service since 2000. The barge floats directly on the Ohio River and is restrained between two vertical river cells. The barge plays a vital role in the unloading process of limestone, which is ultimately utilized in the WFGD systems. This deck barge supports the excavator, transfer hopper, feeder belt and the tail section of the main limestone conveyor. The barge has deteriorated over the course of its duty cycle and has reached the end of its useful life. Leaks exist throughout the vessel after years of running aground during low river pool conditions. Hull thinning also exists due to the constant flow of the unit 1 condenser discharge water against the barge. The existing barge framing is not robust enough to support the 200,000 lb. load of a moving excavator. Consequently, the deck and hull support frames are damaged from overloading. The south-end guide failed in 2014 and required emergency repairs to keep the barge from breaking loose. The plant maintains a seven

day stockpile of limestone, however a catastrophic barge failure places significant derate**Although** forced outage risks on the units.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $3,058
  2. Delay One Year: NPVRR: ($000s) $4,145
  3. Do Nothing: NPVRR: ($000s) $178,887

Recommendation – Replace Limestone Barge:
> The purchase and installation of a new limestone barge is the recommended option. This plan has the least cost over the life of the project and avoids the probability of outages for all four units if the barge becomes inoperable.

Alternative 1 – Delay Project One Year:
> This alternative is not recommended because of the added risk associated with delaying the project by a year and the unfavorable NPVRR. The largest associated risk is a barge failure resulting in downtime. If that downtime exceeds the stockpiled backlog of limestone, there would likely be unit outages.

Alternative 2 – Do Nothing:
> The Do Nothing alternative is not recommended because of the unfavorable NPVRR and the uncertain remaining life of the limestone barge. This option has a high probability of causing unit derates and forced outages.

Project Description

- **Project Scope and Timeline**
  The scope of this project includes the purchase and installation of a new limestone unloading barge. A contract to design, build and deliver a new unloading barge will be awarded in the second quarter of 2017. Delivery of the new barge is expected in July 2018. An installation contract will be awarded in early 2018. After completion of the installation the old barge will be scrapped. Removal of the existing barge will be handled by the installation contractor.

  The following details the expected project timeline:
  o Investment Committee presentation   March 2017
  o Award new barge construction bid   April 2017
  o Award installation contract   2nd Quarter 2018
  o New barge delivered   July 2018
  o Installation begins   3rd Quarter 2018
  o Project complete   3rd Quarter 2018

- **Project Cost**
  The total cost of the project is estimated at $2,700k. This includes the purchase of a new limestone barge and delivery, removal of the old barge and installation of the new barge. A contingency of $240k (10%) is included for unexpected costs associated with removal and installation. Project burdens of $106k (4.50% for 2017 and 2018) are included.

Economic Analysis and Risks   **Arbough**

- **Bid Summary**
  The bid summary below is for the purchase and delivery of a new barge. Installation of the new barge and removal of the existing barge will be bid in a separate initiative.

MBE/WBE	██████████████████████
Total Cost ($000s)	██████████████████████

Bids were solicited from six bidders. Five bids were received. Review meetings were conducted with three barge manufacturers ██████████████████████, and ███████ was deemed the best evaluated. ███████ is the low bidder and is able to meet the barge design specifications and equipment requirements indicated in the project scope of work.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	Total
1. Capital Investment Proposed	500	2,000	2,500
2. Cost of Removal Proposed		200	200
3. Total Capital and Removal Proposed (1+2)	500	2,200	2,700
4. Capital Investment 2017 BP	500	2,000	2,500
5. Cost of Removal 2017 BP		200	200
6. Total Capital and Removal 2017 BP (4+5)	500	2,200	2,700
7. Capital Investment variance to BP (4-1)	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	Total
1. Project O&M Proposed			-
2. Project O&M 2017 BP			-
3. Total Project O&M variance to BP (2-1)	-	-	-

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$0
Contract Labor:	$600
Materials:	$1,754
Local Engineering:	$0
Burdens:	$106
Contingency:	$240
Reimbursements:	($0)
Net Capital Expenditure:	$2,700

- **Assumptions**

  Cost estimates for the capital evaluation models include a 2% inflation rate, where applicable.

  The current capital burden rate as of 1/1/2017 is 4.50%. This rate was used to determine the total burden to the project.

  The capital evaluation models only take into account outages associated with Unit 4. The actual outages due to a barge issue causing an outage would likely affect all four units. The assumed barge lead time is 36 weeks.

  For the "Do Nothing" alternative, an 5% annual increase in probability of a major outage is assumed due to repairs to the limestone barge as it ages. This assumption is based on the barge already being at the end of its useful life.

  At the time of this investment proposal, scrap barges similar to the existing limestone barge are bringing around $20k in scrap value. This scrap value is netted against the removal costs to dispose of the existing barge.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	N
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	N
#3	Does the project increase through-put with any of the material handling systems?	N
#4	Will the project affect the dispatch order or utilization of the unit?	N
#5	Does the project increase the emissions unit's maximum hourly heat input?	N

#6	Does the project increase the emissions unit's electrical output (gross MW)?	Arbough N
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced. See Below*	Y
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	N

*Numerous minor repairs to the limestone barge have been made including repair of broken welds and fatigued metal. In 2014, one of the barge guides that holds the barge in place failed and the barge nearly broke free.

- **Risks**
  - <u>Forced Unit Outages</u>: Without replacement of the limestone barge, there is increasing risks for forced outages for all four units. As time passes, the chances of a major problem developing with the existing limestone barge increases.

  - <u>Additional O&M costs</u>: Without replacement of the limestone barge there will be increased O&M costs due to unplanned repairs or maintenance. The existing barge has reached the end of its useful life and the likelihood of increased repairs is significant.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Mill Creek Limestone Unloading Barge Replacement project for $2,700k to avoid the probability of outages for all four units if the barge becomes inoperable.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____
Kent W. Blake
Chief Financial Officer

_____
Paul W. Thompson
President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: February 23, 2017

Project Name: Mill Creek Unit 2 Turbine L-0 Buckets Replacement

Total Expenditures: $2,766k (including $256k of contingency)

Project Number(s): 143635

Business Unit/Line of Business: Power Generation / Mill Creek Station

Prepared/Presented By: Nathan Romero / Joe Didelot

Executive Summary

The last stage (L-0) buckets from the Mill Creek Unit 2 (MC2) low pressure (LP) Turbine have reached the end of their useful life and are in need of replacement. The buckets will be ordered in March 2017 and delivered to the contractor ███████████████████████████) in January 2018, for installation during the outage that begins March 12, 2018. The work scope is recommended by General Electric and LGE-KU's Manager of Turbine-Generator Maintenance.

This project will include replacement of the turbine end (TE) and generator end (GE) (see diagram in the attached appendix) L-0 buckets and associated hardware. The new buckets offer improved cover design which raises the back pressure trip point from 7"Hg to 9"Hg. The new buckets offer no measurable heat rate improvements and no increase in unit capacity.

The total cost of this project is $2,766k, including $256k in contingency. A progress payment of $816k for material is required in 2017, with $1,950k projected for 2018. The project is included in the 2017 BP at $4,000k ($500k 2017, and $3,500k 2018). The additional $316k needed in 2017 will be funded within the current Mill Creek capital plan and has been approved in the 0+12 forecast by the RAC.

Background

The L-0 buckets are the original components commissioned with the MC2 GE turbine in 1972. These 30" buckets (2 rows) have an estimated service life of 30 years.

During the last detailed inspection in 2012, significant erosion was discovered at the trailing edges, near the bucket covers. Due to lead time, replacement buckets could not be obtained during the 2012 outage.

A failure of the buckets would cause damage to the turbine housing and result in a lengthy forced outage. Replacement of the L-0 buckets during the Spring 2018 planned outage will restore reliability of the unit.

- **Alternatives Considered**

  1. Recommendation: NPVRR: ($000s) $3,159
  2. Alternative #1: Delay two years   NPVRR: ($000s) $4,328
     Delaying the project until the next major outage is not recommended because of the risk of forced outage and the increase in material and labor costs.
  3. Alternative #2: Do nothing   NPVRR: ($000s) $52,088
     The do nothing option is not recommended because of the increasing risk of forced outages and lost generation.

Project Description

- **Project Scope and Timeline**

  ➤ Open, inspect, and close the LP turbine assembly.
  ➤ Remove and install new TE and GE L-0 buckets.
  ➤ Low speed balance LP assembly.
  ➤ Install new LP packing and spill strips.

  Milestones:
Project Approval	February 2017
PO issued for material	March 2017
Material Delivery	January 2018
Installation	MC2 Spring Outage (March 2018)

- **Project Cost**

  The total estimated cost of the project is $2,766k, including 10% ($256k) contingency for emergent work that may be uncovered after inspection.

Economic Analysis and Risks

- **Bid Summary**

  The MC2 turbine L-0 buckets capital work scope is included as part of the LKE 2017-18 fleet turbine-generator major outages contract, which was approved by the Investment Committee in October 2016 and awarded to ███████ in November 2016, under contract number 613001. The contract includes fixed pricing through the term of the agreement unless an outage schedule shifts.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	816	1,730	-	-	2,546
2. Cost of Removal Proposed		220	-	-	220
3. Total Capital and Removal Proposed (1+2)	816	1,950	-	-	2,766
4. Capital Investment 2017 BP	500	3,000	-	-	3,500
5. Cost of Removal 2017 BP		500	-	-	500
6. Total Capital and Removal 2017 BP (4+5)	500	3,500	-	-	4,000
7. Capital Investment variance to BP (4-1)	(316)	1,270	-	-	954
8. Cost of Removal variance to BP (5-2)	-	280	-	-	280
9. Total Capital and Removal variance to BP (6-3)	(316)	1,550	-	-	1,234

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.5%
Capital Breakdown:
  Labor: $ 0
  Contract Labor: $ 673
  Materials: $1,729
  Local Engineering: $ 0
  Burdens: $ 108
  Contingency: $ 256
  Net Capital Expenditure: $2,766

- **Assumptions**

Delay Project Two Years alternative: capital costs would increase by 2% each year due to inflation; 1% probability of 36 weeks availability disimprovement starting in 2018, with probability increasing by 2% each year until project completion in 2020.

Do Nothing alternative: 1% probability of 36 weeks availability starting in 2018, with probability increasing by 2% each following year.

Estimated equipment useful life: 30 years.

- **Environmental**

There are no local, state, or federal environmental requirements for permitting, notification, reporting, etc., regarding these repairs. There are no known environmental issues regarding this project.

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	N
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	N
#3	Does the project increase through-put with any of the material handling systems?	N
#4	Will the project affect the dispatch order or utilization of the unit?	N
#5	Does the project increase the emissions unit's maximum hourly heat input?	N
#6	Does the project increase the emissions unit's electrical output (gross MW)?	N
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	N
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	N

Environmental Affairs has reviewed and approved this project.

- **Risks**

Risks associated with delaying or not completing this project include forced outages and significant damage to the turbine/generator. Material and labor costs will increase if the project is delayed.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the MC2 Turbine L-0 Buckets
Replacement project for $2,766k (inclusive of 10% contingency) to maintain turbine reliability.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the
members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the
signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

L-0 BUCKETS

TURBINE
END

GENERATOR
END

LOW PRESSURE TURBINE ROTOR
(SECTION VIEW)
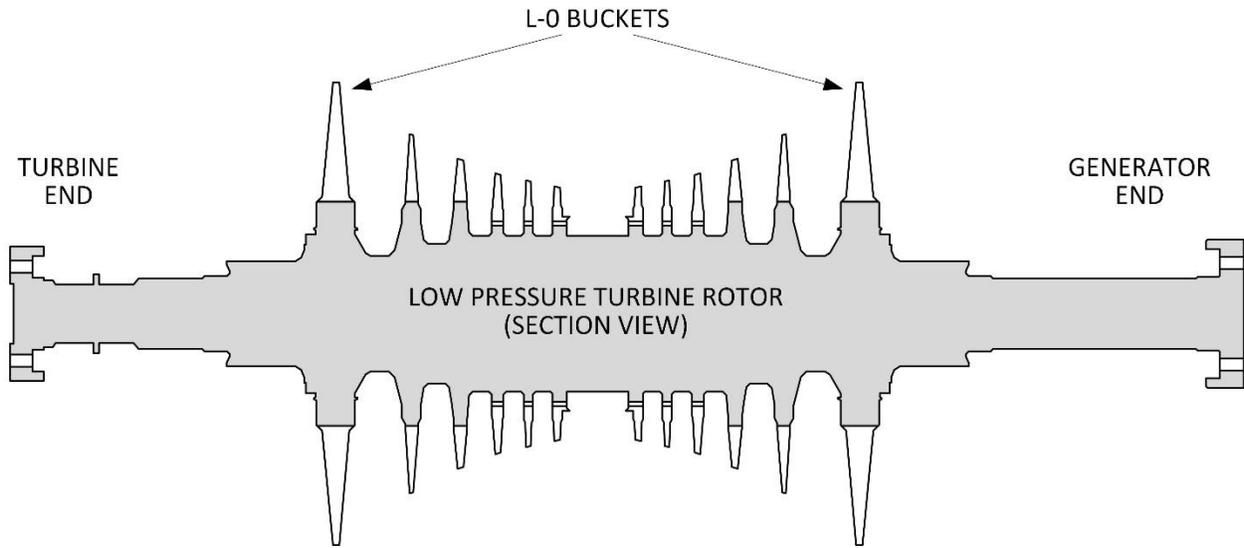
Investment Proposal for Investment Committee Meeting on: November 28, 2017

Project Name: Mill Creek 2 Waterwall Weld Overlay

Total Expenditures: $2,600k   (Including $100k (4%) of contingency)

Project Number(s): 154561

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Rob Meadway

Executive Summary
This project is to mitigate potential boiler tube failures (BTF's) on Mill Creek 2 (MC2) waterwalls from sulfidation/corrosion. Weld overlay is a proven solution to mitigate corrosion in coal fired utility boilers industry wide. Approximately 5,000 sqft of tubing will be weld overlaid in place with a corrosion resistant alloy to restore waterwall tube thickness and prevent future degradation. The weld overlay will be applied to the existing waterwall tubes using automatic welding machines. A small number of panels will be installed to replace any tubing too thin to weld overlay.

The project was initially included in the 2017 BP as project 147055 in years 2021 and 2022 for $2,500k. Project 147055 was cancelled and the current project is included as a 2018 project in the proposed 2018 BP for $2,600k, including $100k contingency. The project was accelerated to address damage from a faster than anticipated corrosion rate. The MC2 dry bottom ash project also presented an 8-week outage opportunity to perform the work.

Background

MC2 was put into commercial operation in 1974. In 1996, it was retrofitted with low NOx burners which contributed to multiple BTFs in the subsequent years from corrosion and sulfidation in the firing zone. To mitigate wastage from corrosion and ensuing tube failures, Project 123325 was executed in 2009 to weld overlay the areas experiencing the worst corrosion. The tubing was overlaid from the top burner elevation to the bottom of the upper arch. Since 2009, bare tubing below the top burner elevation has exhibited continued wall loss due to corrosion. This project will extend weld overlay from the top to bottom burner elevations to restore existing tubing and protect from corrosion.

Shop overlaid and field installed panels were considered, but field weld overlay was chosen given good performance as demonstrated on MC2 (2009) and MC1 (2013). In addition to a good performance history, field weld overlay has been and continues to be more economical.

- **Alternatives Considered**
  1. **Recommendation:**   NPVRR: $3,121k
     Weld overlay waterwalls in place to restore tubing thickness and prevent corrosion degradation.
  2. **Next Available Outage:**   NPVRR: $3,242k
     Delaying the project until the next available outage (2020) will result in higher risk of unavailability.
  3. **Do Nothing:**   NPVRR: $3,637k
     This alternative will enable continued waterwall wastage and decrease availability.

Project Description

- **Project Scope and Timeline**
  This project will remove damaged waterwall sections which exhibit significant wall loss, restore tubing to its original design thickness, and apply a protective high nickel/chrome overlay to mitigate future corrosion degradation from a corrosive, reducing atmosphere.

  Milestones:
Project Approval	December 2017
Field Weld Overlay Application	MC2 Outage (3/10/2018 – 5/6/2018)
Boiler Hydro	April 30, 2018

- **Project Cost**
  The total project cost is estimated at $2,600k and includes a 4% contingency of $100k. The project cost includes $1,687k labor and $665k material.

Economic Analysis and Risks

- **Bid Summary**
  The project is currently in the bid evaluation stage with proposals received from ███████ ██████ and ████████████████████████ No diverse suppliers were identified that could perform this scope of work.

	███	███
MBE/WBE/VBE	████████	████████
Total Cost ($000s)	████████	████████

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed		2,300			2,300
2. Cost of Removal Proposed		300			300
3. Total Capital and Removal Proposed (1+2)	-	2,600	-	-	2,600
4. Capital Investment 2017 BP				2,300	2,300
5. Cost of Removal 2017 BP				200	200
6. Total Capital and Removal 2017 BP (4+5)	-	-	-	2,500	2,500
7. Capital Investment variance to BP (4-1)	-	(2,300)	-	2,300	-
8. Cost of Removal variance to BP (5-2)	-	(300)	-	200	(100)
9. Total Capital and Removal variance to BP (6-3)	-	(2,600)	-	2,500	(100)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The project was included in the 2017 BP as project 147055 for $2,500k with $1,200k in 2021 and $1,300k in 2022.

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$30
Contract Labor:	$1,687
Materials:	$665
Local Engineering:	$0
Burdens:	$118
Contingency:	$100
Reimbursements:	($0)
Net Capital Expenditure:	$2,600

- **Assumptions**
  1. Each BTF will last for an average of 48 hours. This duration is based on a typical leak in the waterwalls including deslag, unit isolation, repair and examination of repair before returning the unit to service.
  2. In the "Do Nothing" alternative, it is expected that there will be two BTF's in 2019 and four BTF's in subsequent years. Tubing thickness readings obtained during the Fall 2016 outage, combined with current wastage rates, support the 75% probability in 2019 and the 90% probability in subsequent years.
  3. Inflation of 2% per year.

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit?	Yes
	a. Is change a like-kind or functionally equivalent replacement?	Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	Yes

Environmental Affairs has reviewed this project.

#7: 123325 (2009)
#8: In 2013 there was one forced outage that was 33.4 hours in duration.

- **Risks**
  1. BTFs are expected to increase if this project is not completed.

Conclusions and Recommendation Arbough

It is recommended that the Investment Committee approve the MC 2 Waterwall Weld Overlay project for $2,600k to ensure continued reliable operation of the boiler.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: <u>June 27, 2018</u>

Project Name: Mill Creek Unit 3 Turbine L-0 Buckets Replacement

Total Expenditures: $2,780k   (Including $245k of contingency)

Project Number(s): 143637

Business Unit/Line of Business: Power Generation / Mill Creek Station

Prepared/Presented By: Nathan Romero / Joe Didelot

Executive Summary

The last stage (L-0) buckets from the Mill Creek Unit 3 (MC3) low pressure (LP) Turbine have reached the end of their useful life and are in need of replacement. The buckets will be ordered in August 2018 and delivered to the contractor, ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮ in August 2019, for installation during the outage that begins October 7, 2019. The work scope is recommended by LGE-KU's Manager of Turbine-Generator Maintenance.

This project will include replacement of the turbine end (TE) and generator end (GE) (see diagram in the attached appendix) L-0 buckets and associated hardware. The new buckets offer improved cover design which raises the back pressure trip point from 7"Hg up to 9"Hg (inches of mercury). The new buckets offer no measurable heat rate improvements or change in unit capacity.

The total cost of this project is $2,780k, including $245k in contingency. A progress payment of $790k for material is required in 2018, with $1,990k projected for 2019. The project is fully funded in the 2018 BP and is included in the proposed 2019 BP.

Background

The existing L-0 buckets are the original components commissioned with the MC3 GE turbine in 1978. These 33.5" buckets (2 rows) have an estimated service life of 30 years. In 2019, the buckets will have over 40 years of service.

A failure of the buckets would cause damage to the turbine housing and result in a lengthy forced outage. Replacement of the L-0 buckets during the Fall 2019 planned outage will maintain reliability of the unit.

- **Alternatives Considered**   **Arbough**
    1. Recommendation: NPVRR: ($000s) <u>$3,118</u>
    2. Alternative #1: Delay two years   NPVRR: ($000s) <u>$3,868</u>
       Delaying the project until the next major outage is not recommended because of the
       risk of forced outage and the anticipated increase in material and labor costs
    3. Alternative #2: Do nothing   NPVRR: ($000s) <u>$44,852</u>
       The do nothing option is not recommended because of the increasing risk of forced
       outages and lost generation.

Project Description

- **Project Scope and Timeline**
    - Open, inspect, and close the LP turbine assembly.
    - Remove and install new TE and MD&A L-0 buckets.
    - Low speed balance LP assembly.

    <u>Milestones:</u>
Project Approval	June 2018
PO issued for material	August 2018
Material Delivery	August 2019
Installation	MC3 Fall Outage (October 2019)

- **Project Cost**
    The total estimated cost of the project is $2,780k, including 10% ($245k) contingency for
    emergent work that may be uncovered after inspection.

Economic Analysis and Risks

- **Bid Summary**
    Bids were solicited from ▮▮ and ▮▮▮▮ in March 2018 and were received in April 2018. While
    negotiations are ongoing, an award to ▮▮▮▮ is anticipated as they provided lowest priced bid.
    The award to ▮▮▮▮ includes supply of the new L-0 buckets and installation of the buckets on
    the LP rotor in ▮▮▮▮'s shop. The contract award will include fixed pricing through the term
    of the agreement unless the outage schedule shifts.

($000s)	
MBE/WBE	
L-0 Bucket Material	
Shop Labor	
Total Cost	

    The labor to open and close the MC3 LP turbine during the Fall 2019 outage was bid under a
    separate fleet inititative. Those bids are due in June 2018 and award is expected in October 2018.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	790	1,790			2,580
2. Cost of Removal Proposed		200			200
3. Total Capital and Removal Proposed (1+2)	790	1,990	-	-	2,780
4. Capital Investment 2018 BP	1,000	2,475			3,475
5. Cost of Removal 2018 BP		500			500
6. Total Capital and Removal 2018 BP (4+5)	1,000	2,975	-	-	3,975
7. Capital Investment variance to BP (4-1)	210	685	-	-	895
8. Cost of Removal variance to BP (5-2)	-	300	-	-	300
9. Total Capital and Removal variance to BP (6-3)	210	985	-	-	1,195

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 986
Materials:	$1,339
Local Engineering:	$ 0
Burdens:	$ 210
Contingency:	$ 245
Reimbursements:	($ 0)
Net Capital Expenditure:	$2,780

- **Assumptions**

Delay Project Two Years alternative: capital costs would increase by 2% each year due to inflation; 1% probability of 41 weeks availability disimprovement starting in 2019, with probability increasing by 2% each year until project completion in 2021.

Do Nothing alternative: 1% probability of 41 weeks availability disimprovement starting in 2019, with probability increasing by 2% each following year.

Estimated equipment useful life: 30 years.

- **Environmental**   Arbough

There are no local, state, or federal environmental requirements for permitting, notification, reporting, etc., regarding these repairs. There are no known environmental issues regarding this project.

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	N
#2	Does the project involve equipment that is part of a regulated air emission unit?	Y
	a. Is change a like-kind or functionally equivalent replacement?	Y
#3	Does the project increase through-put with any of the material handling systems?	N
#4	Will the project affect the dispatch order or utilization of the unit?	N
#5	Does the project increase the emissions unit's maximum hourly heat input?	N
#6	Does the project increase the emissions unit's electrical output (gross MW)?	N
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	N
	a. Provide frequency or when equipment or component in question was last repaired or replaced.	
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment?	N
	a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	

Environmental Affairs has reviewed and approved this project.

- **Risks**

Risks associated with delaying or not completing this project include forced outages and significant damage to the turbine/generator. Material and labor costs will likely increase if the project is delayed.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the MC3 Turbine L-0 Buckets project for $2,780k (inclusive of 10% contingency) to maintain turbine reliability.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:		DocuSigned by:
kent Blake	6/28/2018 | 1:26 PM EDT	*Paul Thompson* 6/28/2018 | 2:29 PM EDT
C055E669F1EB443...		57F10AF68231455...
Kent W. Blake Date		Paul W. Thompson Date
Chief Financial Officer		Chairman, CEO and President

Appendix

L-0 BUCKETS

TURBINE
END

GENERATOR
END

LOW PRESSURE TURBINE ROTOR
(SECTION VIEW)

Investment Proposal for Investment Committee Meeting on: May 30, 2017

Project Name: Mill Creek 4 (MC4) Condenser Retube

Total Expenditures: $3,510k (Including $295k (7.5%) of contingency)

Project Number(s): 127590

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Vince Cecil / Joe Didelot

Executive Summary

The MC4 Condenser Project involves replacing the remaining 75% of condenser tubing in the fall 2018 outage.

In 2012, a condenser inspection by TEi Engineering revealed cracking and erosion damage to the hotwell wall, at the penetrations of the high energy steam drains. In the fall of 2014, this section of wall was replaced along with 25% of the condenser tubing to provide access to the working area.

Inspections and eddy current testing performed during the fall 2014 outage indicated considerable thinning of the 27,000 remaining tubes. Since 2014, approximately 550 of the tubes have failed. The most prevalent failure mode was inlet-end erosion caused by the turbulent flow at the inlet of the tubes. The only option for returning this condenser to a reliable state is the replacement of the original tubing.

The proposed plan for the fall 2018 outage is to replace the remaining original tubing in the condenser. Repairs will also be made to the hotwell internal structures, as needed to restore the condenser and hotwell to original condition. This project was included in the 2017 BP for $6,000k. A total of $1,100k has been reallocated from 2018 to 2017 to purchase material and install two isolation valves and was approved by the RAC in the 3+9 forecast.

Background

The MC4 Condenser is a Westinghouse 268,000 ft^2 rectangular surface condenser, commissioned in 1982, with 36,336 total tubes. The existing tubes are 0.875" O.D., 0.035" wall, 90-10 copper-nickel and are 32'-6 1/4" long. The tubes are roller expanded into 2" thick Muntz metal tubesheets.

The 4A1 condenser waterbox was retubed in 2014 and the north hotwell wall was replaced. The remaining three boxes of the condenser are the original 90-10 copper-nickel tubes. The 35 year old tubes are 5 years past their expected design life, per EPRI's guideline for typical operation.

Below are the tube maps for the 4B2 upper and lower tube banks. The tubes highlighted in green **Although** were plugged before 2014, the tubes marked in red are the tubes that failed since the fall 2014 outage.
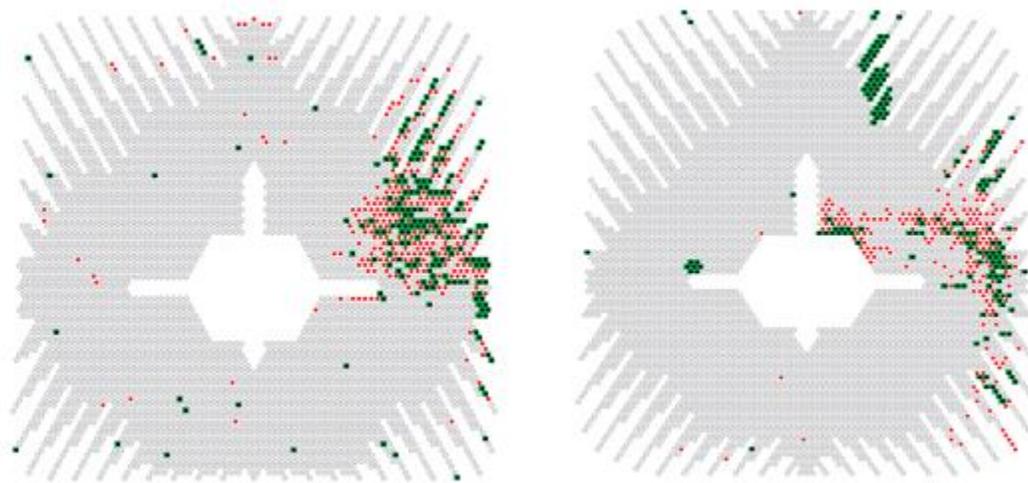
The MC4 condenser has four main 72'' butterfly isolation valves. In 2016 the 4A2 and 4B1 isolation valves were replaced. This project encompasses replacing the remaining two isolation valves (4A1 and 4B2). The new valves will minimize leakage, reduce outage time, and improve the safety of personnel in the waterboxes.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $4,875
       Replace the remaining MC4 condenser tubing along with the 4A1 and 4B2 condenser isolation valves during the fall 2018 outage.

    2. Alternative #1:   NPVRR: ($000s) $5,728
       This alternative postpones the project until the next available outage in 2022. This is not recommended because the delay will increase the risk for derates and forced outages. Also, the cost for labor and materials would increase due to inflation and commodity pricing fluctuation (assumed at 2%).

    3. Alternative #2:   NPVRR: ($000s) $29,003
       This alternative should not be chosen because of the increased risk for derates and forced outages.

Project Description

- **Project Scope and Timeline**
    o This project encompasses replacement of the original condenser tubing. The project also includes replacing the 4A1 and 4B2 main condenser isolation valves.

o The material, as well as the method for retubing, is well proven in the industry. Although Mill Creek Units 2 and 3 were retubed in 2012 and 2016 respectively, using a similar material and process.

Milestones:

- Project Approval   May 2017
- PO issued for material   June 2017
- Labor Awarded   Fall 2017
- Material Received   Fall 2017
- Valve Installation   Fall 2017
- Tubing installation   Fall 2018

- **Project Cost**
  This project includes $295k contingency for fluctuation in raw copper pricing as well as potential repairs identified during the outage, such as tube-sheet, water box studs, or bracing during the 2018 installation. A formal bid process will be completed in the fall of 2017.

Economic Analysis and Risks

- **Bid Summary**
  Quotes were received from five tube suppliers in March 2017. Upon an internal review of each supplier's quality control measures and work history, the recommendation is to utilize the tubing provided from ▋▋▋▋▋▋. ▋▋▋▋▋▋ provided the only domestic sourced option and is the OEM for all the Mill Creek condensers. While ▋▋▋▋▋▋ did not provide the lowest priced offering, a higher level of Quality Assurance/Quality Control would be required for other globally sourced suppliers, offsetting the additional cost (see Appendix A).

MC4 Condenser Tube Supply	
$000s	
MBE/WBE/VBE	
Mfg. Source	
Material Bid	
LG&E QA/QC Costs	
Cost w/ QA/QC	

A budgetary installation quote was obtained with formal bidding of the tubing labor expected to be completed in the fall of 2017. Procurement of the valves and installation labor will be completed in the summer of 2017, to prepare for installation during the fall 2017 outage.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,100	1,310	-	-	3,410
2. Cost of Removal Proposed	-	100	-	-	100
3. Total Capital and Removal Proposed (1+2)	2,100	1,410	-	-	3,510
4. Capital Investment 2017 BP	1,000	4,500			5,500
5. Cost of Removal 2017 BP		500			500
6. Total Capital and Removal 2017 BP (4+5)	1,000	5,000	-	-	6,000
7. Capital Investment variance to BP (4-1)	(1,100)	3,190	-	-	2,090
8. Cost of Removal variance to BP (5-2)	-	400	-	-	400
9. Total Capital and Removal variance to BP (6-3)	(1,100)	3,590	-	-	2,490

Financial Summary ($000s):

Discount Rate: 6.5%
Capital Breakdown:
  Labor: $30
  Contract Labor: $1,310
  Materials: $2,475
  Burdens: $100
  Contingency: $295
  Salvage: ($700)
  Net Capital Expenditure: $3,510

- **Assumptions**
  1. Tube leaks currently account for a half week of lost availability per year and increase 15% yearly until the re-tube is complete.
  2. A 2% escalation is included in the 2022 alternative.
  3. The financial impact of a forced outage due to complete failure of the MC4 condenser was not considered.
  4. The estimated useful life of the re-tubed MC4 Condenser is thirty years.
  5. O&M savings (tube plugging, condensate treatment, etc.) were not included in the financial model.
  6. The CEM model maximum lost availability for derates and outages, for the "Do Nothing" case, is seven weeks.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	No
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. MC4 condenser partial retube and north wall repair in 2014.	Yes
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? See GADS data below.	Yes

Environmental Affairs is currently reviewing the project.

Mill Creek Condenser Tube Leak GADS (2012-2017)							
Event	Type	Start	End	Cause	Description	Eq Hrs	Eq MWH
35	MO	2/21/2012	2/24/2012	3110	Condenser Tube Leak	63.3	30,780
68	U1	5/1/2013	5/2/2013	3110	Condenser Tube Leak	36.1	17,228
262	U1	12/10/2014	12/13/2014	3110	Condenser Tube Leak	74.6	36,272
272	U1	12/16/2014	12/18/2014	3110	Condenser Tube Leak	50.6	24,600
95	MO	9/5/2015	9/7/2015	3110	Condenser Tube Leak	46.9	22,387
2	MO	1/9/2017	1/10/2017	3110	Condenser Tube Leak	23.4	11,356

- **Risks**
  If the project is postponed, the condenser tubes will continue to fail at a higher rate leading to reduced availability. As the percent of plugged tubes increases over 10%, the impact to performance may become more significant.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Mill Creek 4 Condenser Retube
project for $3,510k to reduce the risk of lost generation and to improve the reliability of the condenser.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the
members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the
signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

MC4 Condenser Tube Supply - Additional Cost Breakdown	
$000s	
Mill Visit & Inspection	
QA/QC- 3rd Party Labor During Fabrication	
QA/QC - 3rd Party Lab Work	
Additional Shipping	
Additional Install Cost	
Engineering Support	
LG&E QA/QC Costs - Total	

Investment Proposal for Investment Committee Meeting on: June 28, 2017

Project Name: Meter Asset Management System (MAM)

Total Approved Expenditures: $6,429k Capital (Approved on 02/16/2017)

Total Revised Expenditures: $10,500k Capital

Project Number(s): 154011, 154013, 154014, and TBD Meter Asset Project #s

Business Unit/Line of Business: Customer Services / IT

Prepared/Presented By: Joan Ferch / David Huff

Reason for Revision

The original investment proposal was approved in February 2017 for $6,429k (see Appendix A). An additional $4,071k is necessary to complete the MAM project. A breakdown of the additional costs are shown below.

$000s	
Approved Project Spend	**$6,429**
LKE Labor – Timeline Extension	$270
Reduced License Fee	($389)
System Integrator/Vendor Design Scope and Timeline Extension	$2,845
Incremental Scope:	
Meter Test Boards and Scanners	$1,045
BI Strategy and Delivery	$300
Total Adjustments	**$4,071**
Revised Total Project Spend	**$10,500**

The increase of $4,071k is incremental. The 2017 amount was approved in the June Corporate RAC meeting and the 2018 amount is in the proposed 2018 Business Plan. As originally assessed, it was thought that the Company's existing meter test boards would be compatible with the MAM system to be implemented. However, after Investment Committee approval, detailed planning and design work revealed that the test boards are not compatible with the MAM and thus would require manual test record loading, reducing much of the efficiency gained with the system. Further evaluation revealed that some of the oldest existing test boards are at 16 years of age and do not support the testing of advanced meter functionality like service switching. The Company tests almost 58,000 electric meters annually. The automation of meter testing with the replacement test boards supports realization of benefits from the MAM implementation. Due to these concerns, it is recommended that the Company replace 28 of the existing 37 test boards and field kits.

Additionally, purchases for scanners associated with new inventory controls and the inclusion of internally developed business reports in the Company's Business Intelligence (BI) platform have added scope. Incremental O&M in 2017 and 2018 is related to user training delivery.

As the Company has progressed with planning and design activities to implement the MAM it is evident that the original 9-month implementation timeline is at risk. The Company has worked diligently and prudently with the MAM vendor ▇▇▇▇ to pull the expected implementation back to October 31, 2017, but no longer feels it is possible. Challenges encountered have been numerous but primarily centered on a theme of documentation completeness, slowing the Company from progressing through design approvals (therefore adding time to this process) and ultimately allowing ▇▇▇▇ to begin development. Based on these challenges, the Company is projecting MAM implementation on March 1, 2018. This 4-month delay does not impact the ▇▇▇▇ delivery cost as it was contracted on a fixed cost basis. The time extension does result in additional cost associated with internal LKE labor as well as System Integrator (SI) labor. The Company is confident that the delivered system will meet the Company's needs and deliver multiple operational benefits. First, the MAM will unify disparate and disjointed PSC reporting systems across electric and gas meter testing. This unification ensures consistency in regulatory reporting and provides increased flexibility to meet evolving regulatory reporting needs. Additionally detailed inventory management tracking allowing improved asset procurement. Furthermore, the Company will benefit from automating existing manual processes across gas and electric assets.

Another factor in the increased cost of the MAM is the deferral of the overall AMS program, resulting in increased overhead costs attributed directly to the MAM, rather than being allocated over several applications' initiatives in the AMS full deployment scope.

Alternatives considered include the releasing of SI resources to reduce or eliminate the incremental expenditure request but evaluations based on internal labor delivery projected MAM implementation around Q4 2018. This delay would significantly impact the Company's ability to incorporate the change management aspects of the MAM into daily operations.

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.49%	6.49%	
Capital Breakdown:			
Labor:	$690	$854	Extension through March 2018
Contract Labor:	$2,600	$5,445	SI Scope and extension through March 2018
Materials:	$300	$1,345	$1,045k for meter test board replacements and scanners
Local Engineering:	$0	$0	
License/Warranty	$1,800	$1,411	
Burdens	$575	$711	Extension through March 2018
Contingency:	$464	$734	
Reimbursements:	($0)	($0)	
Net Capital Expenditure:	$6,429	$10,500	
NPVRR:	$7,177	$13,126	

Financial Detail by Year - Capital ($000s)	2017	2018	Post 2018	Total
1. Capital Investment Proposed	8,136	2,364		10,500
2. Cost of Removal Proposed				-
3. Total Capital and Removal Proposed (1+2)	8,136	2,364	-	10,500
4. Capital Investment 2017 BP	1,616	3,389	1,424	6,429
5. Cost of Removal 2017 BP				-
6. Total Capital and Removal 2017 BP (4+5)	1,616	3,389	1,424	6,429
7. Capital Investment variance to BP (4-1)	(6,520)	1,025	1,424	(4,071)
8. Cost of Removal variance to BP (5-2)	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(6,520)	1,025	1,424	(4,071)

Financial Detail by Year - O&M ($000s)	2017	2018	Post 2018	Total
1. Project O&M Proposed	214	456	807	1,477
2. Project O&M			1,237	1,237
3. Total Project O&M Variance to BP (2-1)	(214)	(456)	430	(240)

The 2017 amount was approved by the Corporate RAC in June and the total increase will be reflected in the proposed 2018 BP and is incremental funding.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the $4,071k revision request for the MAM project for a revised total of $10,500k to ensure resource continuity, enable maximum business efficiency associated with the automation between the MAM system and test boards, and prevent further delays in schedule.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Appendix A

Case No. 2018-00295
Attachment to Response to AG-2 Question No. 33(b)
Page 284 of 616

Investment Proposal

Arbough

Investment Proposal for Investment Committee Meeting on: Presented November 29, 2016 and subsequent Email Vote February 2017

Project Name: Meter Asset Management System (MAM)

Total Expenditures: $6,429k including $464k of contingency

Total Contract Value (SSA): ███████

Project Number(s): TBD

Business Unit/Line of Business: Customer Services / IT

Prepared/Presented By: Joan Ferch / David Huff

Executive Summary

LG&E and KU Energy LLC (LKE) currently uses ████████████████████████████████ to manage metering assets used to measure and bill for customer usage. ████████ was implemented in April 2009. Currently ████████ has limited functionality around inventory management, sophisticated device characteristics, and lacks advanced field-level security controls. The primary driver of this project is to implement a Meter Asset Management (MAM) system that will serve specific needs related to tracking, testing, Kentucky Public Service Commission (KPSC) reporting, and managing metering assets.

LKE's parent company PPL recently engaged in a similar project for their system utilized in Pennsylvania. PPL's competitive bid evaluation recommended ████████████████████████ LKE evaluated ██████████████████████ software capabilities and determined that it is an appropriate selection to meet LKE business and technical requirements, as well as future strategic metering initiatives.

This project will reflect savings through 2021 of $983k that consists of:
- Labor productivity gains of $450k, achieved through efficiencies and improved utilization of resources due to reduced data entry errors, reduced truck rolls, reduced efforts to locate meters, and reduced time testing electric meters.
- O&M savings of $45k, which is recognized by eliminating the annual maintenance fee for MMS2000.
- Estimated inventory reductions of $488k based on achieving a 15% efficiency factor.

The funding for this initiative was included in the 2017 BP. The amount of the overall project funding related to the MAM is $1,616k in 2017, $3,389k in 2018, and $1,424k in 2019, for a total of $6,429k compared to a total expected cost of $6,429k for 2017.

It is recommended that the investment committee approve this MAM investment proposal to support the current AMS Opt-In program meters, greater inventory control of existing meters, and automation of test boards with this management system to support regulatory reporting requests.

Background

LKE meter data is currently housed in the ███████. Prior to the implementation of ████████, each utility used a separate meter asset system. LGE used the Meter Sub System and KU used the Meter Device Inventory System. At the time of the ███████ original implementation, the functionality within ███████ was considered sufficient to meet the business requirements. Since that time, experience has proven that the ███████ functionality does not provide the full complement of features required to meet LKE's current and future needs related to inventory management, sophisticated device characteristics, and advanced field-level security controls. During the Downtown Network and AMS Opt-In projects, it was determined that Advanced Meters require additional data for meter definition and programming, and additional data to support interfacing the meters to external systems within the AMS architecture. ███████does not provide standard functionality to house and process these advanced characteristics. Additionally, ███████ does not provided standard functionality to track the inventory and deployment of these meters.

The ███████████ MAM was selected for the reasons below.

1) LKE Meter Assets currently utilizes ████████████ that will interface directly with ███████████.
2) ██████ has an established history as an industry leader.
3) LKE Meter Assets has utilized a legacy version of ███████ in a standalone environment in the past.

LKE's parent company PPL reviewed products and proposal by ██████████████ ███████████. PPL determined that ███████████ was their preferred solution. While LKE does not have access to the evaluations due to confidentiality agreements, LKE's review of ███████████ capabilities determined that it is a robust product that meets our technical requirements.

Additionally, as part of the MAM review, four products were reviewed: █████████████ █████████████████████.

Based on the assessment, LKE concluded that ██████ asset management system is indivisibly integrated with ██████ Meter Data Management System (MDMS) to enable an end-to-end ██████ exclusive AMS architecture solution. LKE is planning on implementing the ███████

MDMS. Therefore, the ██████ system is not an acceptable solution that meets LKE's **Arbough**
infrastructure requirements.

██████ suite of asset management software is structured to enable enterprise-wide asset
management of various business functions across an entire organization (i.e., generation,
transmission, distribution, supply chain, etc.). Thus surpassing LKE's requirements achievable
by a less complex, device specific asset management system. Generally, the cost is higher for an
enterprise wide system and would create redundant systems which would not be used.
Consequently, LKE did not pursue detailed evaluation of a ██████ system.

In contrast, ██████ and ██████ products are specifically designed to enable efficiencies and
functions associated with meter asset management. As mentioned previously however, LKE
successfully utilizes and operates ████████████ exclusively. In addition to enabling
seamless integration of analogous software-hardware interfaces, the potential procurement of
████████████ product gives LKE an opportunity to request or negotiate newer or
upgraded test boards. Consequently, ████████ is the most suitable solution to meet
outlined requirements and that will integrate with our existing infrastructure.

The following utilities have been identified as having the ████████ solution currently
deployed. (Note that ████████ has only been available in this enhanced form for less than
two years, although the company has offered many different versions of their software to support
the utility business for more than 20+ years.

Additionally, older versions of ██████ have been deployed at Alabama Power, National Grid,
Florida Power Light, Center Point Energy, Progress Energy, Georgia Power Mississippi Power,
and more than 30 other utilities. The ████████ basic software system is deployed at over
900 utilities.

Inventory tracking today is accomplished through a series of manual processes and spreadsheets
reconciled on an annual basis. ████████ is capable of automating the tracking and
capturing of test records for metering devices; including meters, and other metering related assets
for both electric and gas. The system retains all relevant information necessary to track an
endpoint device across its deployment lifecycle including, but not limited to, device
manufacturer, manufacturer date, installation date and location, serial number, warranty
information, geographic information system (GIS) location of service, maintenance log, and any

scanned records. The inventory tracking system also reconciles field crew handheld devices **Although** (scanners) with back-office systems and has the capability to store records scanned during any service call by field crews. These inventory management processes will enable LKE to more accurately manage inventory level. ███████████ can also support compliance and reporting with all KPSC mandated meter testing processes.

Currently, ████████ is updated manually with all test results. █████████████ will allow for automated integration of the █████████████ (Test Results). This automation will help to eliminate manual data entry errors.

█████████████ will provide the capability to interface meter characteristic data with external systems such as L+G Command Center, L+G Gridstream Meter Data Management System (MDMS), ████████ etc.

The following requirements were identified by LKE Meter Assets as the basic functionality of a MAM:

- Comply with evolving KPSC reporting requirements such as detailed test records for all meters tested and those records to be filed with quarterly reports. The MAM would ensure the data would be properly maintained which would ease scrubbing data to prepare detailed reports like requested by the KPSC
  - o Need for accurate data entry of test results. Test equipment is interfaced with MAM and automatically populates test record preventing data entry errors that occur with manual entry. MAM test records needs to be interfaced to ████████
  - o Provide checks to validate and confirm test result data before saving test record
  - o Delete test records created in error or with erroneous data
- Link photos or images to meter activity record
- Incorporate barcoding in the procurement, inventory and distribution of meter assets to facilitate locating meters
- Provide real time tracking, manufacturing and shipment status information for meter purchase orders with a direct interface with the meter manufacturer
- Provide improved reporting, test comparison, and statistics to management
- Store and track advanced device characteristics such as meter firmware, programs, networking characteristics, and linked devices
- Customize the business rules for inventory management
  - o ████████████ will allow LKE to define "logistic" rules to meter procurement, receipt, inventory, deployment and retirement by enforcing a Next-Step model.
  - o Incorporate 'Sticky Note' and 'Red Tag' technology; electronic alerts that retrieve information for future use (track meters that customer requested test to determine a potential repeatable issue with meter)
- Configure customizable business rules engine for meter test processing

- **Alternatives Considered**
  1. Recommendation: NPVRR: $7,177k

     o Implement ███████████ as proposed. PPL determined that ███████████ met their business requirements when evaluated against ███████████████, and ██████. The LKE investment in ██████ testing technologies supports a software provider for the MAM that integrates with existing infrastructure. Additionally, selecting the same provider for both PPL and LKE provides opportunities for shared support of the system across both companies.

     o ███████████ - This enterprise-wide asset management system was not fully evaluated from a financial standpoint because enterprise-wide systems are historically more expensive than the current proposal and it would provide functionality that is currently provided by other systems. Thus, the ██████ solution is not recommended.

     o ██████ - This asset management system is tightly integrated to ██████ MDMS. LKE is not utilizing the ██████ MDMS and thus integration of this system with ██████ and ███████████ MDMS is considered unacceptable.

     o ██████ - This system is comparable to the ███████████ system, however, it lacks strategic ability to integrate with existing meter testing equipment and would thus reduce planned savings from the integration of the meter test equipment with the ███████████ system. Additionally, based on responses received from the Southeast Electric Exchange (SEE) Metering Committee in regards to MAM implementations, a couple of utilities responded they had tried to implement ██████ and were forced to abandon the implementation of the product. Thus, this system is not recommended.

  2. Do Nothing: NPVRR: N/A

     This option was determined to be unacceptable due to the increasing complexity and costs of the more sophisticated meter asset inventory. As meter hardware becomes more complex, the need to track and store inventory becomes critical to the device characteristics and data integrity. Additionally, KPSC reporting requirements will likely continue to follow the level of meter sophistication. Knowledge gained during the LKE Downtown Network and AMS Opt-In projects has shown the level of data needed to support Advanced Metering appliances has become a critical requirement.

Project Description   **Arbough**

- **Project Scope and Timeline**
  The scope of this project is to implement ███████████MAM software allowing for tighter integration of Metering Assets and improved functionality around tracking, testing, KPSC reporting, and managing metering assets. This was the software selected by PPL after a thorough evaluation of the market.

  > February 2017 – Purchase hardware and software
  > February 2017 – Receive hardware and software
  > July 2017 – Complete build/programming
  > August 2017 – Complete testing
  > September 2017 – Deployment complete/Go live

- **Project Cost**
  Total cost of the project is ███████ of capital and $1,103k of ongoing O&M (compared to on-going O&M in the 2017 BP of $1,237k), for a total on-going O&M of $134k lower than the 2017 BP for the 5 year period. There is a 12% contingency in place for internal labor, vendor professional services and system integrator costs due to the complex nature of the metering assets architecture and criticality of the data integrity for the metering assets used for measuring and billing our customers.

Sole Source Authorization

The work described herein is being sole sourced to ██████████████████████ Signatures on this document will act as approval for the contract to be sole sourced to ███████ for ███████.

Economic Analysis and Risks

- **Bid Summary (N/A – This project was sole sourced based on PPL analysis)**

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	6,429				6,429
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	6,429	-	-	-	6,429
4. Capital Investment 2017 BP	1,616	3,389	1,424		6,429
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	1,616	3,389	1,424	-	6,429
7. Capital Investment variance to BP (4-1)	(4,813)	3,389	1,424	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(4,813)	3,389	1,424	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	39	256	262	546	1,103
2. Project O&M 2017 BP			230	1,007	1,237
3. Total Project O&M variance to BP (2-1)	(39)	(256)	(32)	461	134

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$690
Contract Labor:	$2,600
Materials:	$300
Local Engineering:	$0
License/Warranty:	$1,800
Burdens:	$575
Contingency:	$464
Reimbursements:	($0)
Net Capital Expenditure:	$6,429

- **Assumptions**

  - Based on a 9 month ▮▮▮▮▮▮▮▮ implementation proposal
  - FTE's will be between 7-9, with a mix of internal labor and ▮
  - ▮▮▮▮▮▮▮ can accommodate tracking and test data records for gas meters
  - The selection of ▮▮▮▮▮▮▮▮▮ as the preferred vendor will be sole sourced at LKE based on the following activities:
    - PPL utilized the competitive bid process and selected ▮▮▮▮▮▮▮.

- ▪ LKE evaluated the software application to ensure it sufficiently met th**rbough**
  business requirements
  - o The expected useful life is 5 years, as standard for software implementations.

- **Environmental**

  - o There are no environmental issues with this project.

- **Risks**

  - o If the project is not completed:
    - ▪ Data quality issues will continue to exist with meter test records.
    - ▪ Reduced efficiency to support current and any future KPSC reporting requirements.
    - ▪ Require complex modifications to ███ in order to track and manage advance meter characteristics.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Meter Asset Management System project for $6,429k and approve the contract to ▮▮▮ for ▮▮▮ to improve overall inventory and test results tracking of metering assets.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million and Contract Authority Greater Than or Equal to $10 million bid, or $2 million sole sourced:

The Capital project spending and the contract authority request included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
SSA – ███

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the ███ SSA contract for up to ███

Sourcing Leader	Jessi Logsdon	Proponent/Team Leader	
Supplier Diversity Manager	Eboni Edwards	IT Development & Support	Mike Lowery
Manager - Supply Chain or Commercial Operations	Stephanie Pryor	Director – Supply Chain or Commercial Operations	Mark Schmitt
Director Energy Efficiency & Smart Grid Strategy	David Huff	Vice President	John Malloy

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal

Investment Proposal for Investment Committee Meeting on: Presented November 29, 2016 and subsequent Email Vote February 2017

Project Name: Meter Asset Management System (MAM)

Total Expenditures: $6,429k including $464k of contingency

Total Contract Value (SSA): █████████

Project Number(s): TBD

Business Unit/Line of Business: Customer Services / IT

Prepared/Presented By: Joan Ferch / David Huff

Executive Summary

LG&E and KU Energy LLC (LKE) currently uses ████████████████████████████ to manage metering assets used to measure and bill for customer usage. ██████████ was implemented in April 2009. Currently ██████████ has limited functionality around inventory management, sophisticated device characteristics, and lacks advanced field-level security controls. The primary driver of this project is to implement a Meter Asset Management (MAM) system that will serve specific needs related to tracking, testing, Kentucky Public Service Commission (KPSC) reporting, and managing metering assets.

LKE's parent company PPL recently engaged in a similar project for their system utilized in Pennsylvania. PPL's competitive bid evaluation recommended ██████████████████████. LKE evaluated ██████████████████████ software capabilities and determined that it is an appropriate selection to meet LKE business and technical requirements, as well as future strategic metering initiatives.

This project will reflect savings through 2021 of $983k that consists of:
- Labor productivity gains of $450k, achieved through efficiencies and improved utilization of resources due to reduced data entry errors, reduced truck rolls, reduced efforts to locate meters, and reduced time testing electric meters.
- O&M savings of $45k, which is recognized by eliminating the annual maintenance fee for MMS2000.
- Estimated inventory reductions of $488k based on achieving a 15% efficiency factor.

The funding for this initiative was included in the 2017 BP. The amount of the overall project funding related to the MAM is $1,616k in 2017, $3,389k in 2018, and $1,424k in 2019, for a total of $6,429k compared to a total expected cost of $6,429k for 2017.

It is recommended that the investment committee approve this MAM investment proposal to support the current AMS Opt-In program meters, greater inventory control of existing meters, and automation of test boards with this management system to support regulatory reporting requests.

Background

LKE meter data is currently housed in the ██████. Prior to the implementation of ██████ each utility used a separate meter asset system. LGE used the Meter Sub System and KU used the Meter Device Inventory System. At the time of the ██████ original implementation, the functionality within ██████ was considered sufficient to meet the business requirements. Since that time, experience has proven that the ██████ functionality does not provide the full complement of features required to meet LKE's current and future needs related to inventory management, sophisticated device characteristics, and advanced field-level security controls. During the Downtown Network and AMS Opt-In projects, it was determined that Advanced Meters require additional data for meter definition and programming, and additional data to support interfacing the meters to external systems within the AMS architecture. ██████ does not provide standard functionality to house and process these advanced characteristics. Additionally, ██████ does not provided standard functionality to track the inventory and deployment of these meters.

The ██████ MAM was selected for the reasons below.

1) LKE Meter Assets currently utilizes ██████ that will interface directly with ██████

2) ██████ has an established history as an industry leader.
3) LKE Meter Assets has utilized a legacy version of ██████ in a standalone environment in the past.

LKE's parent company PPL reviewed products and proposal by ██████ ██████. PPL determined that ██████ was their preferred solution. While LKE does not have access to the evaluations due to confidentiality agreements, LKE's review of ██████ capabilities determined that it is a robust product that meets our technical requirements.

Additionally, as part of the MAM review, four products were reviewed: ██████ ██████

Based on the assessment, LKE concluded that ██████ asset management system is indivisibly integrated with ██████ Meter Data Management System (MDMS) to enable an end-to-end ██████ exclusive AMS architecture solution. LKE is planning on implementing the ██████

MDMS. Therefore, the ███████ system is not an acceptable solution that meets LKE's   **Arbough**
infrastructure requirements.

███████ suite of asset management software is structured to enable enterprise-wide asset
management of various business functions across an entire organization (i.e., generation,
transmission, distribution, supply chain, etc.). Thus surpassing LKE's requirements achievable
by a less complex, device specific asset management system. Generally, the cost is higher for an
enterprise wide system and would create redundant systems which would not be used.
Consequently, LKE did not pursue detailed evaluation of a ███████ system.

In contrast, ███████ and ███████ products are specifically designed to enable efficiencies and
functions associated with meter asset management. As mentioned previously however, LKE
successfully utilizes and operates ████████████ exclusively. In addition to enabling
seamless integration of analogous software-hardware interfaces, the potential procurement of
████████████ product gives LKE an opportunity to request or negotiate newer or
upgraded test boards. Consequently, ████████████ is the most suitable solution to meet
outlined requirements and that will integrate with our existing infrastructure.

The following utilities have been identified as having the ████████████ solution currently
deployed. (Note that ████████████ has only been available in this enhanced form for less than
two years, although the company has offered many different versions of their software to support
the utility business for more than 20+ years.

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Additionally, older versions of ███████ have been deployed at Alabama Power, National Grid,
Florida Power Light, Center Point Energy, Progress Energy, Georgia Power Mississippi Power,
and more than 30 other utilities. The ████████████ basic software system is deployed at over
900 utilities.

Inventory tracking today is accomplished through a series of manual processes and spreadsheets
reconciled on an annual basis. ████████████ is capable of automating the tracking and
capturing of test records for metering devices; including meters, and other metering related assets
for both electric and gas. The system retains all relevant information necessary to track an
endpoint device across its deployment lifecycle including, but not limited to, device
manufacturer, manufacturer date, installation date and location, serial number, warranty
information, geographic information system (GIS) location of service, maintenance log, and any

scanned records. The inventory tracking system also reconciles field crew handheld devices ▉although (scanners) with back-office systems and has the capability to store records scanned during any service call by field crews. These inventory management processes will enable LKE to more accurately manage inventory level. ▉▉▉▉▉▉ can also support compliance and reporting with all KPSC mandated meter testing processes.

Currently, ▉▉▉▉ is updated manually with all test results. ▉▉▉▉▉▉ will allow for automated integration of the ▉▉▉▉▉▉ (Test Results). This automation will help to eliminate manual data entry errors.

▉▉▉▉▉▉ will provide the capability to interface meter characteristic data with external systems such as L+G Command Center, L+G Gridstream Meter Data Management System (MDMS), ▉▉▉▉etc.

The following requirements were identified by LKE Meter Assets as the basic functionality of a MAM:

- Comply with evolving KPSC reporting requirements such as detailed test records for all meters tested and those records to be filed with quarterly reports. The MAM would ensure the data would be properly maintained which would ease scrubbing data to prepare detailed reports like requested by the KPSC
    - o Need for accurate data entry of test results. Test equipment is interfaced with MAM and automatically populates test record preventing data entry errors that occur with manual entry. MAM test records needs to be interfaced to ▉▉▉▉▉
    - o Provide checks to validate and confirm test result data before saving test record
    - o Delete test records created in error or with erroneous data
- Link photos or images to meter activity record
- Incorporate barcoding in the procurement, inventory and distribution of meter assets to facilitate locating meters
- Provide real time tracking, manufacturing and shipment status information for meter purchase orders with a direct interface with the meter manufacturer
- Provide improved reporting, test comparison, and statistics to management
- Store and track advanced device characteristics such as meter firmware, programs, networking characteristics, and linked devices
- Customize the business rules for inventory management
    - o ▉▉▉▉▉▉ will allow LKE to define "logistic" rules to meter procurement, receipt, inventory, deployment and retirement by enforcing a Next-Step model.
    - o Incorporate 'Sticky Note' and 'Red Tag' technology; electronic alerts that retrieve information for future use (track meters that customer requested test to determine a potential repeatable issue with meter)
- Configure customizable business rules engine for meter test processing

- **Alternatives Considered**
  1. Recommendation: NPVRR: $7,177k

     o Implement ███████████ as proposed. PPL determined that███████████ met their business requirements when evaluated against ███████████ ██████ The LKE investment in ██████ testing technologies supports a software provider for the MAM that integrates with existing infrastructure. Additionally, selecting the same provider for both PPL and LKE provides opportunities for shared support of the system across both companies.

     o ███████████ - This enterprise-wide asset management system was not fully evaluated from a financial standpoint because enterprise-wide systems are historically more expensive than the current proposal and it would provide functionality that is currently provided by other systems. Thus, the ██████ solution is not recommended.

     o ██████ - This asset management system is tightly integrated to ██████ MDMS. LKE is not utilizing the ██████ MDMS and thus integration of this system with ████ and ███████ MDMS is considered unacceptable.

     o ██████ - This system is comparable to the ███████████ system, however, it lacks strategic ability to integrate with existing meter testing equipment and would thus reduce planned savings from the integration of the meter test equipment with the ███████████ system. Additionally, based on responses received from the Southeast Electric Exchange (SEE) Metering Committee in regards to MAM implementations, a couple of utilities responded they had tried to implement ██████ and were forced to abandon the implementation of the product. Thus, this system is not recommended.

  2. Do Nothing: NPVRR: N/A

     This option was determined to be unacceptable due to the increasing complexity and costs of the more sophisticated meter asset inventory. As meter hardware becomes more complex, the need to track and store inventory becomes critical to the device characteristics and data integrity. Additionally, KPSC reporting requirements will likely continue to follow the level of meter sophistication. Knowledge gained during the LKE Downtown Network and AMS Opt-In projects has shown the level of data needed to support Advanced Metering appliances has become a critical requirement.

Project Description

- **Project Scope and Timeline**
  The scope of this project is to implement ███████████ MAM software allowing for tighter integration of Metering Assets and improved functionality around tracking, testing, KPSC reporting, and managing metering assets. This was the software selected by PPL after a thorough evaluation of the market.

  > February 2017 – Purchase hardware and software
  > February 2017 – Receive hardware and software
  > July 2017 – Complete build/programming
  > August 2017 – Complete testing
  > September 2017 – Deployment complete/Go live

- **Project Cost**
  Total cost of the project is $6,429k of capital and $1,103k of ongoing O&M (compared to on-going O&M in the 2017 BP of $1,237k), for a total on-going O&M of $134k lower than the 2017 BP for the 5 year period. There is a 12% contingency in place for internal labor, vendor professional services and system integrator costs due to the complex nature of the metering assets architecture and criticality of the data integrity for the metering assets used for measuring and billing our customers.

Sole Source Authorization

The work described herein is being sole sourced to ██████ for ███████████. Signatures on this document will act as approval for the contract to be sole sourced to ██████ for ███████.

Economic Analysis and Risks

- **Bid Summary (N/A – This project was sole sourced based on PPL analysis)**

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	6,429				6,429
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	6,429	-	-	-	6,429
4. Capital Investment 2017 BP	1,616	3,389	1,424		6,429
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	1,616	3,389	1,424	-	6,429
7. Capital Investment variance to BP (4-1)	(4,813)	3,389	1,424	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(4,813)	3,389	1,424	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	39	256	262	546	1,103
2. Project O&M 2017 BP			230	1,007	1,237
3. Total Project O&M variance to BP (2-1)	(39)	(256)	(32)	461	134

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$690
Contract Labor:	$2,600
Materials:	$300
Local Engineering:	$0
License/Warranty:	$1,800
Burdens:	$575
Contingency:	$464
Reimbursements:	($0)
Net Capital Expenditure:	$6,429

- **Assumptions**

  - Based on a 9 month ▮▮▮▮▮▮▮▮ implementation proposal
  - FTE's will be between 7-9, with a mix of internal labor and SI
  - ▮▮▮▮▮▮▮▮ can accommodate tracking and test data records for gas meters
  - The selection of ▮▮▮▮▮▮▮▮▮▮ as the preferred vendor will be sole sourced at LKE based on the following activities:
    - PPL utilized the competitive bid process and selected ▮▮▮▮▮▮▮▮

- LKE evaluated the software application to ensure it sufficiently met the **Arbough** business requirements
  o The expected useful life is 5 years, as standard for software implementations.

- **Environmental**

  o There are no environmental issues with this project.

- **Risks**

  o If the project is not completed:
    - Data quality issues will continue to exist with meter test records.
    - Reduced efficiency to support current and any future KPSC reporting requirements.
    - Require complex modifications to ▮▮ in order to track and manage advance meter characteristics.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Meter Asset Management System project for $6,429k and approve the contract to ███████ for ███████ to improve overall inventory and test results tracking of metering assets.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million and Contract Authority Greater Than or Equal to $10 million bid, or $2 million sole sourced</u>:

The Capital project spending and the contract authority request included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
SSA – ███████

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the ████████ SSA contract for up to ██████.

Sourcing Leader	Jessi Logsdon	Proponent/Team Leader	
Supplier Diversity Manager	Eboni Edwards	IT Development & Support	Mike Lowery
Manager - Supply Chain or Commercial Operations	Stephanie Pryor	Director – Supply Chain or Commercial Operations	Mark Schmitt
Director Energy Efficiency & Smart Grid Strategy	David Huff	Vice President	John Malloy

Note: For Contract Proposals greater than $10 million bid, or greater than $2 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: March 28, 2018

Project Name: Meter Asset Management System (MAM)

Total Approved Expenditures: $10,500k Capital (Approved in June 2017)

Total Revised Expenditures: $13,200k Capital

Project Number(s): 154011, 154013, 154014, 155232, 155233

Business Unit/Line of Business: AMS

Prepared/Presented By: Joan Ferch / David Huff

Reason for Revision

The original investment proposal was approved in February 2017 for $6,429k and a revision was approved in June 2017 for an additional $4,071k. Due to additional complexities and challenges, an additional $2,700k is needed to complete the project as detailed below. It is important to note that while the timeline extension (from March 2018 to December 2018) has increased the cost of the project, the Company has worked diligently to mitigate those increases through managing team resources for both internal and System Integrator (SI).

$000s	
Approved Project Spend	**$10,500**
LKE Labor – Timeline Extension	$1,995
Reduced License Fee	($674)
System Integrator/Vendor Design Scope and Timeline Extension	$1,199
Materials / Site Readiness	$137
Incremental Scope:	
Gas Sample Ticket Database / Service Suite Changes	$350
Reduced Contingency	($464)
Other	$157
Total Adjustments	**$2,700**
Revised Total Project Spend	**$13,200**

The increase of $2,700k is incremental. As the Company has progressed with the development of the MAM, several impediments have arisen that put the revised project implementation timeline at risk. Challenges encountered include resource constraints from the MAM vendor ▉▉▉▉ driving limited delivery capabilities, a more complex than anticipated gas module design, the unforeseen system architecture complexity of a multiple meter shop operation, and the work necessary to prepare approximately 40 company sites to house the MAM equipment. ▉▉▉▉

significantly underestimated the effort required to complete the project, which has contributed to delays. Complexities surrounding PSC meter testing based on legislative rules and the fact that electric functionality is not directly transferrable to the gas module design, has unavoidably increased the scope of the project.

As a result of these delays and additional scope, the project has been split into two separate delivery stages. Stage 1 will contain the bulk of the functionality and is anticipated to be complete in July 2018. Stage 2 will primarily contain PSC meter testing functionality, as well as some additional enhancements, and is scheduled to be complete in 4Q 2018. In addition, approximately 40 meter storage and distribution sites throughout the Company's service territory have needed varying degrees of work performed to make them suitable for housing the electronic MAM equipment.

The costs associated with this increase in scope and effort for internal Company labor as well as SI labor is included in this additional funding request. ████ delivery costs are also expected to increase to provide enhancements to their existing system in order to meet Company operational needs. The increases in SI and ████ costs will be covered under their existing approved contract amounts.

Alternatives considered include the releasing of SI resources to reduce or eliminate the incremental expenditure request, but evaluations based on available internal skillsets, and scheduled delivery time frames, projected the MAM implementation into 2019. This delay would significantly impact the Company's ability to incorporate the change management aspects of the MAM into daily operations.

Financial Summary ($000s):	Approved	Revised	Variance	Explanation
Discount Rate:	6.49%	6.58%	0.09%	New approved rate
Capital Breakdown:				
Labor:	$838	$1,926	$1,088	Timeline extension
Contract Labor:	$5,445	$6,644	$1,199	Timeline extension
Materials:	$1,345	$1,482	$137	Site readiness
Local Engineering:	$0	$0	$0	
License/Warranty:	$1,411	$737	($674)	
Incremental Scope:	$300	$650	$350	Gas module design
Burdens:	$697	$1,604	$907	Timeline extension
Contingency:	$464	$0	($464)	
Other:	$0	$157	$157	
Reimbursements:	($0)	($0)	$0	
Net Capital Expenditure:	$10,500	$13,200	$2,700	
NPVRR:	$13,126	$14,227	$1,272	

Financial Detail by Year - Capital ($000s)	2017	2018	Post 2018	Total
1. Capital Investment Proposed	6,053	7,147		13,200
2. Cost of Removal Proposed				-
3. Total Capital and Removal Proposed (1+2)	6,053	7,147	-	13,200
4. Capital Investment 2018 BP	6,136	4,364	-	10,500
5. Cost of Removal 2018 BP				-
6. Total Capital and Removal 2018 BP (4+5)	6,136	4,364	-	10,500
7. Capital Investment variance to BP (4-1)	83	(2,783)	-	(2,700)
8. Cost of Removal variance to BP (5-2)	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	83	(2,783)	-	(2,700)

Financial Detail by Year - O&M ($000s)	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	192	952	1,144
2. Project O&M	-	256	1,091	1,347
3. Total Project O&M Variance to BP (2-1)	-	64	139	203

The incremental funding in 2018 was approved in the February Corporate RAC process.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the $2,700k revision request for the MAM project for a revised total of $13,200k in order to complete the project in a timely manner to facilitate the implementation of the 2018 Company business plan strategies.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____	_____
Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Meter Asset Management System (MAM)

Total Expenditures: $6,429k Including $464k of contingency

Total Contract Value (SSA): ███████

Project Number(s): TBD

Business Unit/Line of Business: Customer Services / IT

Prepared/Presented By: Joan Ferch / David Huff

Executive Summary

LG&E and KU Energy LLC (LKE) currently uses ████████████████████████████ to manage metering assets used to measure and bill for customer usage. ████████ was implemented in April 2009. Currently ████████ has limited functionality around inventory management, sophisticated device characteristics, and lacks advanced field-level security controls. The primary driver of this project is to implement a Meter Asset Management (MAM) system that will serve specific needs related to tracking, testing, Kentucky Public Service Commission (KPSC) reporting, and managing metering assets.

LKE obtained the PPL RFP findings of the vendor analysis related to the PPL MAM implementation project. LKE determined that PPL's evaluation was comprehensive and conclusive to recommend the ██████████████████████ software as an appropriate selection to meet LKE business and technical requirements, as well as future strategic metering initiatives.

This project will reflect savings through 2021 of $533k that consists of:
- O&M savings of $45k, which is recognized by eliminating the annual maintenance fee for MMS2000.
- Estimated inventory reductions of $488k based on achieving a 15% efficiency factor.

Additional productivity gains are anticipated as a result of this project but have not been quantified. These benefits will be achieved through efficiencies and improved utilization of resources due to reduced data entry errors, reduced truck rolls, reduced efforts to locate meters, and reduced time testing electric meters.

The funding for this initiative was included in the 2017 BP as a component of the overall LKE AMS project. The amount of the overall AMS project funding related to the MAM is $1,616k in

2017, $3,389k in 2018, and $1,424k in 2019, for a total of $6,429k compared to a total enough cost of $6,429k for 2017.

Background

LKE meter data is currently housed in the ▮▮▮▮▮▮ Prior to the implementation of ▮▮▮▮▮▮, each utility used a separate meter asset system. LGE used the Meter Sub System and KU used the Meter Device Inventory System. At the time of the ▮▮▮▮▮▮ original implementation, the functionality within ▮▮▮▮ was thought to be sufficient to meet the business requirements. Since that time, additional experience has proven that the ▮▮▮▮▮ functionality does not provide the full complement of features required to meet LKE's current and future needs as discussed above. During the Downtown Network and AMS Opt-In projects, it was found that Advanced Meters require additional data for meter definition and programming, and additional data to support interfacing the meters to external systems within the AMS architecture. ▮▮▮ ▮▮ does not provide standard functionality to house and process these advanced characteristics. Additionally, ▮▮▮▮▮ does not provided standard functionality to track the inventory and deployment of these meters.

The ▮▮▮▮▮▮▮▮ MAM was selected as the preferred product for a variety of reasons.

1) LKE Meter Assets currently utilizes ▮▮▮▮▮▮▮▮ that will interface directly with ▮▮▮▮▮▮

2) ▮▮▮▮ has an established history as an industry leader; further validated by the Gartner Group.

3) LKE Meter Assets has utilized a legacy version of ▮▮▮▮▮ in a standalone environment in the past.

Research by parent company PPL determined that ▮▮▮▮▮▮▮ rated higher than other products reviewed by PPL. The other MAM products reviewed with vendors by PPL were ▮▮▮▮▮▮▮▮▮▮▮.

Inventory tracking today is accomplished through a series of manual processes and spreadsheets reconciled on an annual basis. ▮▮▮▮▮▮ is capable of automating the tracking and capturing of test records for metering devices; including meters, and other metering related assets for both electric and gas. The system retains all relevant information necessary to track an endpoint device across its deployment lifecycle including, but not limited to, device manufacturer, manufacturer date, installation date and location, serial number, warranty information, geographic information system (GIS) location of service, maintenance log, and any scanned records. The inventory tracking system also reconciles field crew handheld devices (scanners) with back-office systems and has the capability to store records scanned during any service call by field crews. These inventory management processes will enable LKE to more accurately manage inventory level. ▮▮▮▮▮▮ can also support compliance and reporting with all KPSC mandated meter testing processes.

Currently, ███████ is updated manually with all test results. ████████████ will allow ███████ Although automated integration of the ████████████ (Test Results). This automation will help to eliminate manual data entry errors.

████████████ will provide the capability to interface meter characteristic data with external systems such as L+G Command Center, L+G Gridstream Meter Data Management System (MDMS), ███████ etc.

The following requirements were identified by LKE Meter Assets as the basic functionality of a MAM:

- Comply with evolving KPSC reporting requirements such as detailed test records for all meters tested and those records to be filed with quarterly reports. The MAM would ensure the data would be properly maintained which would ease scrubbing data to prepare detailed reports like requested by the KPSC
  - Need for accurate data entry of test results. Test equipment is interfaced with MAM and automatically populates test record preventing data entry errors that occur with manual entry. MAM test records needs to be interfaced to ███████
  - Provide checks to validate and confirm test result data before saving test record
  - Delete test records created in error or with erroneous data
- Link photos or images to meter activity record
- Incorporate barcoding in the procurement, inventory and distribution of meter assets to facilitate locating meters
- Provide real time tracking, manufacturing and shipment status information for meter purchase orders with a direct interface with the meter manufacturer
- Provide improved reporting, test comparison, and statistics to management
- Store and track advanced device characteristics such as meter firmware, programs, networking characteristics, and linked devices
- Customize the business rules for inventory management
  - ████████████ will allow LKE to define "logistic" rules to meter procurement, receipt, inventory, deployment and retirement by enforcing a Next-Step model.
  - Incorporate 'Sticky Note' and 'Red Tag' technology; electronic alerts that retrieve information for future use (track meters that customer requested test to determine a potential repeatable issue with meter)
- Configure customizable business rules engine for meter test processing

- **Alternatives Considered**
  1. Recommendation: NPVRR: $7,666k
     Implement ████████████ as proposed. The research by parent company PPL determined that ████████████ is best of class, accompanied with the LKE investment in ███████ testing technologies limits the ability to transition to a different software provider for the MAM.

2. Do Nothing: NPVRR: N/A   **Arbough**

> This option was determined to be unacceptable due to the increasing complexity and costs of the more sophisticated meter asset inventory. As meter hardware becomes more complex, the need to track and store inventory becomes critical to the device characteristics and data integrity. Additionally, KPSC reporting requirements will likely continue to follow the level of meter sophistication.   Knowledge gained during the LKE Downtown Network and AMS Opt-In projects has shown the level of data needed to support Advanced Metering appliances has become a critical requirement.

Project Description

*   **Project Scope and Timeline**
    The scope of this project is to implement ▮▮▮▮▮▮▮▮ MAM software allowing for tighter integration of Metering Assets and improved functionality around tracking, testing, KPSC reporting, and managing metering assets. This was the software selected by PPL after a thorough evaluation of the market.

    > January 2017 – Purchase hardware and software
    > January 2017 – Receive hardware and software
    > July 2017 – Complete build/programming
    > August 2017 – Complete testing
    > September 2017 – Deployment complete/Go live

*   **Project Cost**
    Total cost of the project is $6,429k of capital and $1,103k of ongoing O&M (compared to on-going O&M in the 2017 BP of $1,237k), for a total on-going O&M of $134k lower than the 2017 BP for the 5 year period. There is a 12% contingency in place for internal labor, vendor professional services and system integrator costs due to the complex nature of the metering assets architecture and criticality of the data integrity for the metering assets used for measuring and billing our customers.

Sole Source Authorization

The work described herein is being sole sourced to ▮▮▮▮▮▮▮▮▮▮▮. Signatures on this document will act as approval for the contract to be sole sourced to ▮▮▮ for ▮▮▮▮

Economic Analysis and Risks

- **Bid Summary (N/A – This project was sole sourced based on PPL analysis)**

  LKE utilized PPL vendor analysis and reviewed their bid process and results to make a recommendation for the proposed vendor. The bid results were used in the negotiations of the vendor pricing to ensure prudency of vendor cost.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	6,429				6,429
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	6,429	-	-	-	6,429
4. Capital Investment 2017 BP	1,616	3,389	1,424		6,429
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	1,616	3,389	1,424	-	6,429
7. Capital Investment variance to BP (4-1)	(4,813)	3,389	1,424	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(4,813)	3,389	1,424	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	39	256	262	546	1,103
2. Project O&M 2017 BP			230	1,007	1,237
3. Total Project O&M variance to BP (2-1)	(39)	(256)	(32)	461	134

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Labor:	$690
Contract Labor:	$2,600
Materials:	$300
Local Engineering:	$0
License/Warranty:	$1,800
Burdens:	$575
Contingency:	$464
Reimbursements:	($0)
Net Capital Expenditure:	$6,429

Financial Analysis - Project Summary ($000)	2017	2018	2019	2020	2021	Life of Project
Project Net Income	$ 469	$ 192	$ 137	$ 82	$ 27	$ 909
Project ROE	19.0%	15.1%	10.0%	10.0%	10.0%	13.2%

- **Assumptions**

  - Based on a 9 month ▮▮▮▮▮▮ implementation proposal
  - FTE's will be between 7-9, with a mix of internal labor and SI
  - ▮▮▮▮▮▮ can accommodate tracking and test data records for gas meters
  - The selection of ▮▮▮▮▮▮ as the preferred vendor will be sole sourced at LKE based on the following activities:
    - PPL utilized the competitive bid process, which was shared with, and reviewed by LKE IT and LOB resources
    - LKE evaluated the software application to ensure it sufficiently met the business requirements
  - The expected useful life is 5 years, as standard for software implementations.

- **Environmental**
  - There are no environmental issues with this project.

- **Risks**

  - If the project is not completed:

    - Data quality issues will continue to exist with meter test records.
    - Reduced efficiency to support current and any future KPSC reporting requirements.
    - Require complex modifications to ▮▮ in order to track and manage advance meter characteristics.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Meter Asset Management System project for $6,429k and approve the contract to ███ for ███ to improve overall inventory and test results tracking of metering assets.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

The Capital project spending and the contract authority request included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
SSA – ▊▊▊▊

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the ▊▊▊▊▊ SSA contract for up to ▊▊▊▊.

Sourcing Leader	Jessi Logsdon		
Supplier Diversity Manager	Eboni Edwards	IT Development & Support	Mike Lowery
Manager - Supply Chain or Commercial Operations	Stephanie Pryor	Director – Supply Chain or Commercial Operations	Mark Schmitt
Director Energy Efficiency & Smart Grid Strategy	David Huff	Vice President	John Malloy

Note: For Contract Proposals greater than $4 million bid, or greater than $1 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.

Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: Mount Vernon South Substation

Total Expenditures: $4,440k (includes $404k contingency)

Project Number(s): Substation-148685, Distribution-152793, Transmission-137750

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jim Burns/Beth McFarland

Executive Summary
Electric Distribution Operations (EDO) Electric Engineering and Planning (EEP) seeks funding authority to construct a new Mount Vernon South 12kV Substation to meet the electrical service needs of existing customers in Mount Vernon in Rockcastle County, Kentucky. The existing Mount Vernon 12kV substation 589-2, serves 1,912 customers and is projected to exceed Distribution Planning's normal winter transformer loading limit of 120% of the 14 MVA top nameplate rating during the winter of 2018/2019. This investment proposal provides for the construction of a new substation inside the fence of the Mount Vernon 094 69kV transmission station and construction of tie circuits to eliminate overloading and prepare for future load growth in the area. In addition to resolving the overloading of the existing Mount Vernon transformer, this project also removes the Mount Vernon 589-2 and Pine Hill 592-1 substations from EDO's Distribution Substation Transformer Contingency Program (N1DT) list (transformers that cannot be fully backed up for an outage or failure of the substation transformer during high load periods).

Funding is requested in the amount of $4,440k to complete a system enhancement project to construct the new Mount Vernon South 094-5 22.4 MVA 69/12kV substation to meet existing and future service requirements and to remove two transformers from EDO's N1DT list. Project completion is expected in November 2018.

The project is included in EDO's 2017 Business Plan (BP) as a 2017/2018 project for a total cost of $2,740k ($2,600k-distribution, $140k-transmission). The budget shortfall of $1,700k in 2018 was identified when a more detailed engineering analysis was completed. Additional funding needed in 2018 will be addressed through requested allocation from identified sources in the 2018 BP Corporate RAC process.

Background
The existing Mount Vernon 12kV (589-2) substation serves 1,912 customers and consists of a 14 MVA 69-12kV transformer and three feeder breakers and is located in the city of Mount Vernon in Rockcastle County, Kentucky. The Mount Vernon substation transformer experienced an actual load of 126% of its 14MVA top nameplate rating during the extreme cold of 2015. The

normalized load forecast projects it to reach 122% during Winter 2018/2019 under normal winter loading conditions. The Distribution Planning allowable winter loading limit for substation transformers is 120%. Pine Hill 12kV (592-1) substation is located roughly six miles from Mount Vernon substation and serves 515 customers and has a 5.25 MVA transformer and three feeder breakers and has a peak winter load of approximately 3.4 MVA. These two substations are tied by a weak distribution circuit tie that is a combination of small and large conductor. In addition to poor voltage performance, conductor and transformer capacity limitations prevent shifting any significant load from Mount Vernon to Pine Hill substation. Furthermore, System Planning studies indicate that the addition of transformer capacity near the city of Mount Vernon (load center) is the best option to resolve overloads because of voltage issues that arise due to the six mile distance to the nearest geographical substation (Pine Hill).

Alternative solutions considered to address the overload conditions included an upgrade of the existing Mount Vernon 589-2 transformer, the addition of a second transformer at the existing Mount Vernon substation or the construction of a new substation in another location. The existing Mount Vernon 589-2 distribution substation does not have adequate physical space for a second transformer and adjacent land for expansion would be difficult and costly to obtain because the substation is surrounded by residences on two sides and roads on two sides. A solution to upgrade the existing Mount Vernon 589-2 substation would include replacing the existing 14 MVA transformer with a 22.4 MVA unit but physical constraints make reconstruction of the facilities to accommodate a larger transformer and additional breaker very difficult. This option would require a temporary substation to be constructed to maintain service and require the installation of a mobile transformer for an extended period of time; tying mobile transformers up for extended periods is not recommended due to their extensive use in emergency situations. This option would also only add 8.4 MVA of new capacity to the area and would provide no improvement in distribution or transmission contingency.

EEP determined that the most feasible solution is to construct a new substation at another location. The Mount Vernon 094 69kV transmission substation is located on the southwestern edge of Mount Vernon and has ample space for a new 12kV substation with direct access to transmission. A new distribution substation at the 094 transmission substation in addition to construction of two tie circuits would add 22.4 MVA of new capacity to address area loads, require minimal transmission construction, improve transmission reliability for the radial transmission line serving Mount Vernon and would provide contingency capacity for Mount Vernon 589-2 substation and the Pine Hill substations removing them from the N1DT list. This option was determined to be superior to the construction of a new substation at a new location because it does not involve property acquisition or transmission line extension costs.

A Transmission Service Request for a new service point at the Mount Vernon 094 69kV substation will be submitted to TranServ International and no resulting transmission improvements are expected.

- **Alternatives Considered**
1. Recommended Option**:**   NPVRR: ($000s) $5,070
   EEP's recommended option is to construct a new 69-12kV 22.4 MVA distribution substation, Mount Vernon South, in the Mount Vernon 094 69kV substation, including 69kV and 12kV substation structures, two 69kV breakers, one 2000 amp 15kV main breaker and two 1200

amp line breakers. Construction of 3,100' of double circuit 397AA three phase along an borough existing overhead route is also included in this project. This will eliminate overloading of Mount Vernon, support new growth, and provide year round contingency for the existing Mount Vernon substation and also for Pine Hill 592-1 substation. While capacity enhancement is the primary driver for this project, the selected option is also consistent with the objectives of the transmission grid resiliency program by providing contingency for a transmission outage on the .5 mile radial transmission tap serving Mount Vernon substation. A long duration outage on the transmission tap, whether unplanned or planned for maintenance needs, results in an outage for the majority of customers served from Mount Vernon substation. The recommended option will reduce the duration of customer outages for longer duration transmission outages. In addition to resolving the overloading of the Mount Vernon transformer, this project also removes the Mount Vernon 589-2 and Pine Hill 592-1 substations from EDO's N1DT list. The estimated total cost of this option is $4,440k.

2. Do Nothing Option: NPVRR: ($000s) N/A
   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating limits for distribution substation power transformers, and this practice reduces the life of the transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1 - Upgrade Mount Vernon substation to 22.4 MVA. NPVRR: ($000s) $8,610
   While this alternative eliminates the potential transformer overload it does not result in the same benefits as the recommended option and does not result in the lowest NPVRR when the Cost of Unserved Energy is considered. This alternative results in a less flexible and reliable system for both distribution and transmission, provides less new capacity to serve future load growth in the area (8.4 MVA vs. 22.4 MVA) and does not remove the Mount Vernon 589-2 substation from EDO's N1DT list. It also requires the long term commitment of a mobile transformer which could potentially be needed to address a transformer failure or to support planned maintenance at other area stations. Failure of the Mount Vernon transformer would result in an extended outage to a large majority of the 1,912 customers until a new transformer or mobile transformer could be installed. While the loss of an entire substation is a relatively low probability event, planning studies indicate an outage of the Mount Vernon substation at peak would cause as much as 15,600 kW to go unserved until the station is restored. Using the corporate "Cost of Unserved Energy" ($17.2/kWh) with estimated loads going unserved at peak for an incremental 22 hours (24 hours less 2 hours to switch load), the Cost of Unserved Energy would be $5,903k for a Mount Vernon outage. The estimated annualized benefit based on an annual 5% probability of an outage or failure of the Mount Vernon or Pine Hill substation is $295k. The estimated total capital cost for this option is $2,390k.

Project Description
- **Project Scope and Timeline**
  - Substation project #148685: Construct new Mount Vernon South 12kV substation with a 22.4 MVA 69-12kV LTC transformer. This estimate includes funds for labor, primary equipment, protection and control, material, and wildlife protection for a 22.4 MVA transformer, 69kV and 12kV substation structures, two 69kV breakers, one 15kV 2000A

breaker, and two 15kV 1200A line breakers. The total estimated substation cost is **Arbough** $3,900k.

- Apr-May 2017: Complete engineering and design. Order all material and equipment.
- Jun-Dec 2017: Receive material and equipment. Begin site preparation and foundations.
- Jan-Dec 2018: Complete foundations and install transformer, steel, breakers and all associated materials and equipment. Complete all secondary and protection and control work. Commission and energize the new substation.

o Distribution project #152793: Design and construct 3,100' of double circuit 397AA spacer circuit. The total estimated distribution cost is $400k.
- Mar-Aug 2018: Design and complete all distribution circuit construction.

o Transmission project #137750: Install new dead end structure, upgrade adjacent structure. The total estimated transmission cost is $140k.
- Feb-Mar 2018: Complete construction of 69kV structures.

- **Project Cost**
  The total estimated cost to complete the Mount Vernon South 094-5 12kV Substation project is $4,440k. The Transmission, Substation and Distribution cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% of contingency ($404k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  Transmission, Substation, and Distribution will use existing material and labor contracts and follow established Supply Chain procedures. KU Company crews will be utilized based on availability at the time of work.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,100	3,244			4,344
2. Cost of Removal Proposed	-	96			96
3. Total Capital and Removal Proposed (1+2)	1,100	3,340	-	-	4,440
4. Capital Investment 2017 BP	1,099	1,641			2,740
5. Cost of Removal 2017 BP	-	-			-
6. Total Capital and Removal 2017 BP (4+5)	1,099	1,641	-	-	2,740
7. Capital Investment variance to BP (4-1)	(1)	(1,603)	-	-	(1,604)
8. Cost of Removal variance to BP (5-2)	-	(96)	-	-	(96)
9. Total Capital and Removal variance to BP (6-3)	(1)	(1,699)	-	-	(1,700)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2017 BP is lower than the requested amount by $1,700k – all of which is in 2018 and will be requested for allocation from identified sources through the 2018 BP process.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 261
Contract Labor:	$ 1,233
Materials:	$ 1,876
Local Engineering:	$ 380
Burdens:	$ 267
Contingency:	$ 404
Transportation:	$ 19
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 4,440

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - No significant unknown costs for transmission improvements will be associated with the addition of a new service point.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**   **Arbough**
  Failure to complete this project before winter 2018/2019 will result in substation transformer loading above normal operating limits and escalating potential for failure of the Mount Vernon 589-2 substation transformer and an extended outage for up to 1,912 customers.

Conclusions and Recommendation   Arbough

EDO EEP recommends that the Investment Committee approve the Mount Vernon South Substation project for $4,440k to prevent overloading at Mount Vernon substation, ensure adequate capacity is available for future load growth in the Mount Vernon area, improve distribution and transmission reliability and remove the Mount Vernon 589-2 and Pine Hill 592-1 substations from EDO's N1DT list.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: <u>February 28, 2018</u>

Project Name: <u>Norton Service Center/Storeroom Consolidation & Land Purchase</u>

Total Expenditures: <u>$ 4,875k (Including $288k of contingency or 6%)</u>

Project Number(s): <u>149992/156576</u>

Business Unit/Line of Business: <u>Customer Services/Electric Distribution Operations (EDO)</u>

Prepared/Presented By: <u>Zac Conley/Cheryl Bruner/Robby Trimble</u>

Executive Summary

During 2014, Facilities Services conducted a study to assess the condition of key operations and customer facilities and to facilitate development of a master facility investment and maintenance plan. This study revealed numerous functional inadequacies and space constraints at the existing Norton operations center and Business Office that cannot be remedied through renovation or expansion of the present facilities.

To address identified deficiencies, Electric Distribution Operations (EDO), Customer Services and Facilities Services seek funding authority of $4,875k to construct a new joint operations center and storeroom for the Norton, VA service territory. The requested funding shall provide for design and construction of an 18,543 square foot facility on a previously purchased 3.4 acre parcel and purchase of an adjacent 1.75 acre parcel, in a centralized and readily accessible light industrial park located 4 miles from the existing Service Center/Storeroom and 2 miles from the Norton Business Office (BO).

The new operations center will contain:
- Office space for 25 personnel from EDO, Meter Reading, Field Services, and Material Services and Logistics;
- Adequate restrooms, shower and locker rooms, break area and conference room space;
- Wellness Center with fitness equipment;
- Assembly Room of sufficient size to be used for meetings and training or as a "Storm Operations Management Room" or "War Room" during major outage events;
- Dedicated and secure IT/Telecommunications and site Fire/Security systems rooms; and
- Storage space for vehicles, materials, equipment, pole storage and transformer storage and containment.

This joint proposal will address primary Norton Business Office and service center inadequacies identified in the master facility study. Vehicle congestion and office space constraints at the Business Office will be eliminated through the relocation of 12 Distribution, Metering, and Field Services personnel to the proposed new operations center. Operational constraints associated with

land size, materials handling processes, and periodic site flooding at the existing service center will be eliminated. Co-locating all Distribution, Meter Reading, Field Services, and Materials Logistics personnel from two sites, and the pole-yard from a third site, to a single work location, will provide operational benefits and efficiencies as further described herein. Finally, the new properties will provide for a much needed area for vehicles and materials staging during significant outage events in the Norton service territory.

The approved 2018 BP includes funding of $3,107k in 2018 and $1,422k in 2019. The project is currently open for engineering and design work, and $72k has been spent to-date.

Background
The current Service Center/Storeroom facilities in Norton are approximately 50 years old and have been in use with only minor renovations to date. Over the course of time, operational needs of the Norton service area have grown beyond the capabilities of the existing facilities, therefore, Service Technicians, Engineering and Design, Forestry, Reliability, Team Leader, and Operations Manager are located at the Norton Business Office. Deficiencies of the Service Center/Storeroom site include:

- The size of the lot cannot accommodate the bulldozer and other large equipment. As a consequence, this equipment must be kept ten miles away at the pole yard in Big Stone Gap.
- The road leading to the site can only accommodate large truck traffic coming one way due to a low-level bridge. Any traffic issue on this road could and has impacted EDO in responding to outage situations.
- An employee must be present at the facility to receive deliveries and allow for garbage pickup. This presents an issue coordinating times for an available employee to be present.
- There is not a secured server room at the Service Center/Storeroom and no space is available to accommodate a server room or to provide a secured area for servers.
- The Service Center/Storeroom is not equipped with a backup generator or manual transfer switch to allow for a portable backup generator to power the facility.
- Additionally, the following operational issues have been dealt with repeatedly throughout the years:
  o The Service Center/Storeroom is not located within the city limits of Norton. Wise County does not maintain the roads leading to the Service Center/Storeroom well and is slow to remove snow during winter time. The City of Norton has better roads and is much quicker to respond to snow removal, which would result in improved access to the main roads for quicker response.
  o The Service Center/Storeroom location is in a remote area, and the fence has been compromised numerous times and equipment and wire have been stolen repeatedly throughout the years.
  o Insufficient space exists for a conference room, training room and Wellness Center;
  o Site accessibility limitations present significant challenges for material deliveries and large equipment ingress and egress;
  o No secured parking is available for Company vehicles;
  o The existing site sits adjacent to a river, and has experienced periodic flooding, and increased environmental challenges.

The Service Center/Storeroom does not have the real estate to accommodate a pole yard. The current pole yard is located ten miles away in Big Stone Gap, requiring crews to travel an average of 40 minutes roundtrip in ideal travel conditions to retrieve poles. In inclement weather, this travel time can be extended due to road conditions and reduced visibility. Co-location of the pole yard to a new facility is expected to lower vehicle fuel costs and reduce crew labor costs associated with the travel time to the pole yard, which is expected to result in improved outage response times, thereby enhancing customer satisfaction. The additional land purchase will also provide space to facilitate staging of vehicles and materials during outage events.

The construction of a new consolidated operations center is desired to provide a location that would place operations in a location suitable for the current needs of the business, resolve ongoing facility inadequacies and constraint issues, enhance operational efficiency, and allow for co-location of operations employees.

Alternatives Considered (1 – Recommendation; 2 – Do nothing)

1. Recommendation: Construct New Facility   NPVRR: $6,696k

   The recommendation is to construct a new facility which will consolidate and replace the existing Service Center/Storeroom and Pole Yard, as well as provide a new location for a number of personnel who currently report out of the Business Office location, which will alleviate the space and parking constraints at the Business Office. Because the existing Service Center/Storeroom will no longer be utilized by EDO following construction of the new facility, and only minimal maintenance will be performed to keep the facility dry and vegetation from overtaking the premises, an annual O&M savings of approximately $39k will be recognized. Co-location of the pole yard to the new facility is expected to lower vehicle fuel costs and reduce crew labor costs associated with the travel time to the pole yard (equating to capital savings of approximately $28k for labor and $5k for fuel), which is also expected to result in improved outage response times, thereby enhancing customer satisfaction.

2. Do Nothing: NPVRR: NA

   This alternative is not recommended as it will not achieve the current and future operational needs of the business. Based upon the functional adequacy evaluation conducted at these facilities in 2014, numerous facility functional needs were identified to provide for the operational needs of the occupants. Examples of these inadequacies are: material delivery vehicles cannot deliver directly to the facility and must park on the adjacent road, lack of space for secure parking within the fence for employees, contractors and visitors, facility is not equipped with a conference room, training room, "War Room" or provisions to support health and employee wellness. These issues cannot be corrected at the existing facilities due to existing property size, physical facility size and location of both operational facilities. Because of these constraints, significant capital investment into the existing facilities will not result in providing facilities that meet the functional adequacy requirements of the occupants. Facility is in a low-lying area that is prone to flooding; site is not adequate for staging materials and has limited security for storage area and employee vehicles; there is not enough land to expand the existing facilities; and the pole yard is not co-located with the Storeroom resulting in operational inefficiencies. If this option is chosen, O&M and capital expenses are expected to increase in the near, mid and long-term based on the age and condition of the facility.

Project Description   **Arbough**

This project will replace the current Service Center/Storeroom facility and provide an additional Pole Yard site through the construction of a new, consolidated facility. Design will commence in April 2018 and construction will begin in July 2018. Construction will take 12 months to complete. The new building will be operational by August 2019.

- **Project Scope and Timeline**
    The project scope includes the following:
    - Site development to prepare for new construction;
    - Design and construction of a 18,543 square foot, efficient, cross-functional facility;
        - o Office space for EDO, Meter Reading and Field Services
            - ▪ 20 EDO personnel includes Operations Manager, Office Support Personnel, Design, Reliability and Inspection, Forestry Services, along with Service/Lines Crews and Supervision
            - ▪ 4 Meter Reading and Field Services Personnel
            - ▪ 1 Storeroom Materials Clerk
        - o Staging area for EDO Operations materials and equipment
        - o Material storeroom with external storage space for poles and transformers
        - o Dedicated, secured space for telecom and security systems
        - o Adequate break room, restroom and locker room facilities for employees
        - o Wellness Center and Special Needs Room
        - o Assembly Room / Training Room / War Room
        - o Vehicles garaging and tool storage
            - ▪ Garaging for trucks and all other equipment
        - o Designed with energy efficiency lighting and HVAC systems
    - Purchase of the 1.75 acre property adjacent to the existing site

    - O&M costs include:
        - o Building Maintenance Costs:
            - ▪ HVAC
            - ▪ Lawn Care
            - ▪ Snow Removal
            - ▪ Janitorial Service/Consumables
            - ▪ Pest Control
            - ▪ Phone/Cable Service
            - ▪ Fitness Equipment Maintenance

Milestone	Start Dates:
RFP Issued	11/23/2017
Investment Committee Review	02/28/2018
Award Bid	03/21/2018
Design	04/01/2018
Construction	07/15/2018
Operational	08/01/2019

- **Project Cost**
  The projected cost is $4,875k, which includes $288k of contingency or approximately 6% of the total project. The contingency was calculated based on 7% of the construction and furnishings cost. Furniture, security and telecommunications equipment and pole racks will be purchased through preferred business partners already under contract. Capital funding of $4,591k was included in the 2018 Business Plan (BP). The property purchase will occur in 2018.

Economic Analysis and Risks

- **Bid Summary**

  Five companies were requested to submit bids for the proposed new operations center. Three of the five companies showed interest and attended the pre-bid. Three bids were ultimately received and are currently being evaluated.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2015	2016	2017	2018	2019	2020-2022	Total
1. Capital Investment Proposed	15	48	10	3,107	1,696	-	4,875
2. Cost of Removal Proposed	-	-	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	15	48	10	3,107	1,696	-	4,875
4. Capital Investment 2018 BP	15	48	-	3,107	1,422	-	4,591
5. Cost of Removal 2018 BP	-	-	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	15	48	-	3,107	1,422	-	4,591
7. Capital Investment variance to BP (4-1)	-	-	(10)	-	(274)	-	(284)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	(10)	-	(274)	-	(284)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	2018	2019	2020-2022	Total
1. Project O&M Proposed	-	-	-	-	(5)	(21)	(26)
2. Project O&M 2018 BP	-	-	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	5	21	26

Capital funding of $4,591k was included in the 2018 BP. The incremental capital amount in 2019 will be handled through the 2019 BP process. O&M costs in the CEM include an incremental $5k annually (escalated) to cover additional expenses due to incremental office space square footage and property size, offset by a reduction in O&M at the existing storeroom. These incremental operating expenses will be incorporated into the 2019 BP.

Financial Summary ($000s):   **Arbough**

Discount Rate: 6.58%

Capital Breakdown:

Labor:	$ 50
Contract Labor:	$ 1,803
Contract Materials:	$ 2,476
Miscellaneous:	$ 127
Burdens:	$ 131
Contingency:	$ 288
Reimbursements:	$ 0
Net Capital Expenditure:	$ 4,875

Materials include company purchases of furniture, Data/Voice/Telecom and security equipment.

- **Assumptions**

Economic useful life is 50 years.

- **Environmental**

Environmental factors due to site soil conditions created by strip mining in the past. Soils may require remediation of existing subsurface mine spoils in order to adequately support the building foundation.

- **Risks**
  - The completion date is contingent on the weather.
  - Obtaining permits and easements.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the Norton Operations Center/Storeroom Consolidation Project for $4,875k which includes incremental land purchase of $130k. The current location of the Service Center/Storeroom is in a flood plain and does not have sufficient land to meet operational needs for additional office/storage space, company vehicle/equipment, and employee parking. Additionally, a number of personnel will relocate from the Norton Business Office, which will serve to alleviate the space and parking constraints at the Business Office, which will continue operations in downtown Norton.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	President and Chief Operating Officer

Arbough

Investment Proposal for Investment Committee Meeting on: September 27, 2017

Project Name: Ohio Falls Unit 7 Stator Core Restack and Rewind

Total Expenditures: $7,650k   (Including $650k in Contingency)

Project Number: 155705

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: John Williams

Executive Summary

This Investment Proposal seeks Project authorization to fund the LG&E Ohio Falls (OF) Generating Station's Unit 7 stator core restack, stator core rewind, and thrust bearing replacement. It is similar to scope performed on the other seven units as part of the overall station rehabilitation project.

As background, Unit 7 was the first unit to be rehabilitated. Going into the power upgrade rehabilitation of the station, the condition of each units' stator/generator was uncertain and thus the original scope of the rehabilitation project did not include the scope requested herein. During the rehabilitation of the second unit (Unit 6) it was discovered that the condition of the stator and thrust bearing on that unit were to a point that rehabilitation of the stator and replacement of the thrust bearing was required. After reviewing operational data, it was determined that all future units that are all the same vintage were predicted to be in similar condition and that the benefits of the rehabilitation and increased generation would not be realized without performing a stator core restack and rewind, along with replacement of the thrust bearing. The increased authorization approved at the time only included refurbishment of the stator/generator and thrust bearing of the second and all future units to be rehabilitated and did not include going back into Unit 7 that was deemed marginal, yet satisfactory, at the time of its rehab.

During the operation of Unit 7 during the spring/summer of 2017 the unit has been load limited due to a deteriorating condition of the stator. As the Unit rises in load, generating additional megawatts (MW), the generator stator core temperature rises. At present, the existing 90 year old Unit 7 stator core rises too quickly and reaches alarm, thus limiting its generation output. Unit 7 consistently generates 10%-15% less MW than the other refurbished units. In addition, the trend of Unit 7 shows deterioration of its capacity; the unit's stator core is rising in temperature more quickly as time passes, resulting in incremental decreases in MW output. Similar to the stator core, the thrust bearing on Unit 7 has not been upgraded in 90 years and is also experiencing excessive temperatures. During normal operation, the Unit 7 thrust bearing is very near alarm level, indicating it has reached the end if its design life. Without this rehab of the stator, it is predicted Unit 7 will reach the point of complete failure, thus rendering the Unit idle. Performing

the scope listed herein will allow Unit 7 to generate at the new higher designed output, though placing the unit condition and equipment to similar condition as the other seven units rehabbed.

The Project authorization requested is $7,650k, inclusive of $650k in management contingency, and is included in the draft 2018 Business Plan (BP); the Corporate RAC has approved the 2017 funding. The work will be substantially performed by ████████████████████ under a change order to the existing Amended and Restated Engineering, Procurement, and Construction Agreement, as ████ is currently performing upgrades on OF Unit 8 and has performed the same stator and bearing work on the other seven (7) units.

Background

An effort began in 2004 to upgrade and refurbish the OF's eight (8) hydroelectric units, which had not seen a major overhaul since originally placed into service in the mid-1920s. OF Unit 7 was the first of the eight (8) units to undergo the refurbishment, which did not include the effort to replace the stator core, stator core windings, and thrust bearing.

The subsequent seven (7) units did receive replacement stator core, stator core windings and the thrust bearing. Those units are realizing the increased MW output as designed without operational concerns or derates due to stator temperatures. In comparison of Unit 7 to the other units in operation that received the stator and bearing upgrades, the existing 90 year old Unit 7 stator core operates at excessive temperatures. During high loads, the stator core operates at a temperature above engineering recommendations and the unit is reduced in load to protect the stator core laminates from catastrophic failure. In addition, during normal operating conditions, the thrust bearing also operates at excessive temperature and very near alarm, an indicator of an end-of-life condition. This project seeks approval to upgrade the stator and bearing of OF Unit 7 to achieve and sustain the design MW output through the refurbishment design life.

Project Description

- **Project Scope and Timeline**

  ████ is currently performing upgrades on OF Unit 8 (the last unit to be rehabilitated) and has performed the same stator and bearing work on all other units. ████ will supply the stator core windings and all necessary installation items. ████ will perform the disassembly of the generator, installation of the winding platform, restack and rewind the stator, and reassemble the unit (inclusive of the thrust bearing).

  Project Engineering will supply the thrust bearing from a third party, ████████ who has provided the other seven (7) thrust bearings. Project Engineering will also supply the laminates.

  Project Milestones
  - Procurement of raw materials   September 2017
  - Manufacturing of windings   October 2017
  - Windings, thrust bearing, and laminates delivered to site   February 2018

- Stator core restacked
- Mechanical Completion

- **Project Cost**

The Project authorization requested is $7,650k, inclusive of $650k in management contingency, and is included in the draft 2018 BP. Table 1 below expresses the project spend:

Table 1: Project Spend

EPC (Voith) Activities	$ 5,600
Balance of Plant	
Thrust Bearing	$ 330
Stator Core Laminates	$ 270
Headgate/Tailgate Work	$ 250
Stator Disassembly, Water Level Event(s), Abatement	$ 190
PE Overhead	$ 360
Contingency	$ 650
Total =	$ 7,650

Economic Analysis and Risks

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	Total
1. Capital Investment Proposed	1,564	6,086	7,650
2. Cost of Removal Proposed	-	-	-
3. Total Capital and Removal Proposed (1+2)	1,564	6,086	7,650
4. Capital Investment 2018 BP	1,564	6,086	7,650
5. Cost of Removal 2018 BP	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,564	6,086	7,650
7. Capital Investment variance to BP (4-1)	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-

This project was not included in the 2017 BP, but is included in the proposed 2018 BP. The 2017 funding was approved by the Corporate RAC.

NPVRR: $8,516k

- **Risks**

The OF Unit 7 stator core and thrust bearing are operating at temperatures nearing alarm setting, effectively limiting the unit's output to well below refurbishment design level. Further, the trend of the stator core temperature indicates that the core will rise in temperature more quickly as time passes, resulting in continued declination of output until an eventual catastrophic failure.

Should a catastrophic or significant failure occur, the replacement laminates, thrust bearing, and other specialized parts/equipment are long lead items.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Ohio Falls Unit 7 Stator Core Rewind and Restack project for $7,650k, inclusive of $650k in management contingency, to complete upgrades to Unit 7 to achieve and sustain the design MW output through the refurbishment design life.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Revised Investment Proposal for Investment Committee Meeting on: April 26, 2017

Investment Proposal:
Project Name: Ohio Falls Rehabilitation
Total Approved Expenditures: $136,000k
Total Revised Expenditures: $140,500k
Project Number(s): Various

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: John Williams

Reason for Revision

This Amended Investment Proposal seeks authorization to increase the Ohio Falls Rehabilitation Project sanction from the February 2016 approved sanction of $136,000k, to a revised sanction of $140,500k. Attachment 1 contains the February 2016 approved Project sanction and contract authorization. There is no request to increase the contract authorization for ███████████████████████████████ ████████████ Agreement beyond the 2016 approval. This request is to account for Balance-of-Plant (BOP) issues experienced during rehabilitation of the last two units, as well as final scopes to restore the overall station site to a safe condition from impacts of the large retrofit project. Drivers of the sanction increase are: experienced and future risks of high and low water events hampering critical path activity; BOP and overhead expenses associated with EPC Excusable Events experienced since the February 2016 sanction that were not covered in the that sanction; and plant betterment and site restoration scopes performed to historical preservation standards that were not in the last sanction. Approval of this amendment is justified by existing Federal Energy Regulatory Commission (FERC) requirements and the requirement to complete mechanical refurbishment of the final hydroelectric unit at Ohio Falls (Unit 8, Sequential Unit 8). Table 1 summarizes Project sanction and contract authorization request:

Table 1: History of Project and ███████████████████

($000s)	2004	2010	2012	2016	2017
████████████████	N/A	$80,000	$83,900	$88,250	$88,250
OF Rehabilitation Project Sanction	$75,000	$130,500	$130,500	$136,000	$140,500

This project was included in the 2017 BP for $138M. Additional funding of $3.4M in 2017 was approved in the 3+9 RAC Forecast. A revised Authorized Investment Proposal will be sent for approval.

Background

An effort began in 2004 to upgrade and refurbish the Ohio Falls Generating Station's eight (8) hydroelectric units, which had not seen major overhaul since they were placed into service in the mid-1920s. Seven (7) units have undergone this work, with Unit 4 (Sequential Unit 7) receiving mechanical completion in the fourth quarter of 2016. All seven (7) units completed to date are performing very well to plan. Unit 8 (Sequential Unit 8 and the last) is currently in outage with a planned completion date of the fourth quarter of 2017.

█████████████ has performed the turbine and generator specific upgrades as the EPC prime contractor. However, excluded from ████ scope is BOP work in support of, and concert with, its upgrades. Project Engineering's staff oversees both ████ EPC scope and engineers, procures, and oversees the execution of BOP work.

All instrumentation and electrical, mechanical, hazardous materials abatement and remediation, and large equipment support are excluded from ████ Agreement. This exclusion was determined favorable after review of ████ commercial terms and conditions pertaining to subcontract oversight and procurement mark-up. In addition to the known, base scope, of BOP work, additional work is required to support ████ upon the execution of ████ Excusable Events.

The remaining BOP work spend requested in this proposal is consistent in scope executed on prior units and also includes river dredging immediately upstream of the station, as well as structural repairs to the powerhouse. River dredging of sediment and debris immediately upstream of the unit intakes is required to optimize unit performance, especially on Units 1-3. The powerhouse structural repairs will be performed in accordance with historical preservation requirements, but funding is not sought at this time for Historic Properties Management Program work. Table 2 expresses BOP work required beyond ████ EPC scope that was not captured in the February 2016 Amended Investment Proposal.

Table 2: Balance of Plant Work Not Captured in 2016 Request

($000s)	
Thrust Bearing (manufacture retrofit thrust bearing to replace existing)	$400
Combined, Smaller Work Scopes (control logic support, mechanical, concrete, gate removal, water level impacts, etc.)	$1,650
River Dredging Upstream of Ohio Falls (sediment & debris removal from unit(s) intakes to optimize performance)	$500
Building Remediation (exterior masonry, interior tile, other repairs)	$1,000
Project Engineering Management Oversight	$950
Total Balance of Plant =	$4,500

Financial Summary

This request seeks to increase sanction amount to $140,500k, a $4,500k increase from the previously approved Project Sanction, and equating to a $2,500k increase from the 2017BP budgeted amount. The table below shows financial detail by year for the full Ohio Falls Rehabilitation Project:

Financial Detail by Year - Capital ($000s)	Pre-2017	2017	2018	Total
1. Capital Investment Proposed	117.2	14.9	-	132.1
2. Cost of Removal Proposed	7.4	1.0	-	8.4
3. Total Capital and Removal Proposed (1+2)	124.6	15.9	-	140.5
4. Capital Investment 2017 BP	117.2	12.5	-	129.7
5. Cost of Removal 2017 BP	8.3	-	-	8.3
6. Total Capital and Removal 2017 BP (4+5)	125.5	12.5	-	138.0
7. Capital Investment variance to BP (4-1)	-	(2.4)	-	(2.4)
8. Cost of Removal variance to BP (5-2)	0.9	(1.0)	-	(0.1)
9. Total Capital and Removal variance to BP (6-3)	0.9	(3.4)	-	(2.5)

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised Ohio Falls Rehabilitation project with an increase of $4,500k for a revised total of $140,500k to complete the rehabilitation and upgrade of the last turbine/generator unit at the Ohio Falls Station and other BOP activities required to support this rehabilitation and restore the overall station to a safe condition from impacts during the multi-year rehabilitation.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake
Chief Financial Officer
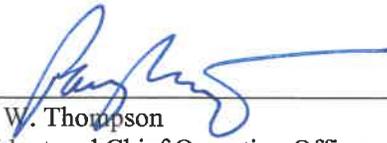
Paul W. Thompson
President and Chief Operating Officer

Victor A. Staffieri
Chairman and Chief Executive Officer

Investment and Revised Contract Proposal for Investment Committee Meeting on: February 24, 2016

Investment Proposal:
Project Name: Ohio Falls Rehabilitation
Total Approved Expenditures: $130,500k
Total Revised Expenditures: $136,000k
Project Number(s): Various

Contract Proposal:
Contract Name: Ohio Falls Rehabilitation
Contractor ████████████
Total Approved Contract Authorization: $83,900k
Total Revised Contract Authorization: $88,250k

Business Unit/Line of Business: Project Engineering

Prepared/Presented By: Joe Strickland and Scott Straight

Reason for Revision

This proposal seeks authorization to increase the previously approved 2010 project sanction of $130,500k to a revised project authorization of $136,000k, inclusive of a 0.3% contingency. This amount will be expended through 2017 to complete the rehabilitation of the LG&E Ohio Falls (OF) Hydroelectric Generating Station. The 2016 Business Plan (BP) has a budget of $139,000k from project inception through 2017. Approval of this revised request is supported by the need to rehabilitate the equipment, existing Federal Energy Regulatory Commission (FERC) requirements, and dam integrity issues. Table 1 below summarizes the previous and current project sanction and contract authorization requests:

Table 1 – History of Project and Voith EPC Authorization

($000s)	2004	2010	2012	2016
████████████	N/A	$80,000	$83,900	$88,250
OF Rehabilitation Project Sanction	$75,000	$130,500	$130,500	$136,000

NOTE: Project Engineering assumed responsibility for the management of the project in the 2010 sanction.

This proposal also seeks a revised contract authorization for the ████████████ ████████████████████████████████ of $88,250k, inclusive of 0% in contingency for any additional Risk Scopes. This increase is anticipated to complete the project unless an "as found" condition not experienced on previous units is realized. It also is to account for the erosion of past contingencies completely absorbed by change orders on the units completed to date (6 of 8 units), as well as the stator core change order in the amount of $8,800k that was not anticipated scope at the time of the 2010 sanction request. It should be noted that this entire sanction increase and the smaller increase in 2012 totals $8,250k, which is essentially the amount of the stator core

change order, thus showing the original sanction in 2010 was accurate for known scope ~~although~~ anticipated "as found" conditions for a rehabilitation project of this scope.

Authorization Increase Background

This EPC revised contract will complete the rehabilitation of all OF Units unless an "as found" condition occurs that is different than those experienced on past units. The amount requested in this contract authorization revision will be expended through 2017 to complete the rehabilitation of the LG&E OF Hydroelectric Generating Station. Table 2 below summarizes the portion of the project related to the ████ EPC.

Table 2

Project Costs	($000s)
████████████████	$88,250
Project – Balance of Plant	$47,750
Total Revised Sanction Request	$136,000

As-found mechanical defects were the primary reasons for the need to execute change orders for OF Units 3, 2 and 1 totaling $3,000k, which were the last three units to be rehabilitated. The total value of change orders to repair or replace items that were listed in Exhibit Z – Risk Scope section of the EPC contract totaled $2,100k. Repairs to the stator core systems and stay flange systems comprise the majority of the Risk Scope related changes. Owner related items and other as-found conditions needing attention comprised the remaining $900k spend. Of the $900k, approximately $700k were responsibility to LG&E (primarily river conditions) and $200k for spare parts not in the original contract.

The Unit 4 rehabilitation (which began in October 2015 and is in progress) exposed that the stay flange requires in-place milling to restore the head cover flatness and levelness to meet current industry specifications, identified in Exhibit Z – Risk Scope (medium risk). Unit 4 will require stator support bar milling tasks as well, with both tasks expected to cost a total $500k.

Inspections made at the ████ fabrication shop in York, Pennsylvania on the wicket gates removed from Unit 2 (the last unit rehabilitated) and intended for Unit 4 revealed that the wicket gates are unable to be rehabilitated and must be replaced to eliminate the chance of a structural failure. Unit 4's wicket gates will be rehabilitated and returned to Unit 4, which will delay the completion of that unit. Since Unit 4's wicket gates were originally going to be used in Unit 8, Unit 8 will now be without a set of wicket gates. To minimize impacts to Unit 8's schedule, a new set of wicket gates is being engineered and fabricated while Unit 4's wicket gates are rehabilitated. The new set of wicket gates will be put into Unit 8. This need to design and fabricate new wicket gates *has not* been experienced to date on the project.

Unit 8's current wicket gates (the last unit to get rehabilitated) will be inspected upon removal from Unit 8. This set of gates will become the plant's replacement spare set (the plant's original spare set

was rehabilitated and used in the first rehabilitated unit at the start of this project). It is anticipated that Unit 8's wicket gates will not be in a condition that will allow a rehabilitation. Therefore, an additional set of new wicket gates is being recommended as the plant's replacement spare set, if existing Unit 8 gates are not suitable for rehabilitation.

Table 3 below is a list of known and anticipated expenses, primarily composed of items from the Contract Exhibit Z Risk Scope items:

<div align="center">Table 3</div>

Additional Costs	($000s)
███████	
Wicket gate related costs	$2,330
Submitted and Pending Change Orders	$430
Anticipated Change Orders (includes Risk Scope Items)	$1,590
Contingency for Unforeseen Events/Items not previously experienced	$0
██████████	$4,350
Project – Balance of Plant	
Project Management Extension (3 months)	$250
Potential High/Low Water Delays	$250
River Related Costs	$250
Contingency for Unforeseen Events/Items (approximately 0.3%) that are Owner Expenses	$400
Subtotal	**$1,150**
Total	**$5,500**

Project Engineering's project management costs for the Ohio Falls Rehabilitation project are forecasted to increase due to the anticipation of the project extending several months into the fall of 2017. In addition, river related costs have been higher than expected due to the record rainfall events over the last two years, and the budget for dewatering and re-watering requires adjustment. Project Engineering's recommendation increases the previously approved project authorization by $250k for the project extension (three months) for Project Engineering overheads, $250k for potential high/low water delays, and $250k for river related work to complete Unit 4, begin and complete Unit 8 and demobilization of the dewatering equipment, gates, and onsite storage.

- 3 -

It is also recommended to add 0.3% contingency to the remaining project budget to allow for completion of the project for smaller unforeseen events. With this contingency, the total project sanction request increases to $136,000k, compared to the 2016 BP total of $139,000k. Also, the 2016BP project estimate included a line item of $700k for Historic Properties Management Program. To date, preservation scope has not been identified, and as such, Project Engineering has removed this amount from the project scope and turned that potential future scope back to the Ohio Falls Station to manage, should it become necessary.

Financial Summary

Financial Summary ($000s): Capital Breakdown:	Approved	Revised	Explanation
Balance of Plant:	$38,100	$47,350	Project delays and river related costs
▉▉▉▉▉▉	$83,900	$88,250	Wicket gate costs and change orders
Contingency:	$8,500	$400	Original contingency absorbed, revised for future unforeseen events
Net Capital Expenditure:	$130,500	$136,000	

Financial Detail by Year - Capital ($000s)	Pre 2016	2016	2017	Post 2017	Total
1. Capital Investment Proposed	106,957	12,273	9,083		128,313
2. Cost of Removal Proposed	5,568	2,119			7,687
3. Total Capital and Removal Proposed (1+2)	112,525	14,392	9,083	-	136,000
4. Capital Investment 2016 BP	108,285	12,273	10,722		131,279
5. Cost of Removal 2016 BP	5,568	2,119			7,687
6. Total Capital and Removal 2016 BP (4+5)	113,853	14,392	10,722	-	138,966
7. Capital Investment variance to BP (4-1)	1,328	(0)	1,639	-	2,966
8. Cost of Removal variance to BP (5-2)	-	0	-	-	0
9. Total Capital and Removal variance to BP (6-3)	1,328	(0)	1,639	-	2,966

Financial Analysis - Project Summary ($000)	2004	2005	2006	2007	2008	Life of Project
Project Net Income	$ (6)	$ (14)	$ 1,362	$ 624	$ 3,091	$ 73,587

Conclusions and Recommendation

It is recommended that the Investment Committee approve the revised Ohio Falls Rehabilitation project for $136,000k, inclusive of 0.3% contingency, to complete the rehabilitation and upgrade of the remaining turbine/generator units at the Ohio Falls Station.

It is also recommended that the Investment Committee approve the revised Ohio Falls Rehabilitation EPC with ▉▉▉ for $88,250k, inclusive of 0% contract management contingency, as well as record the Historic Preservation scope portion of the project has been removed from the project scope.

Joe Strickland
Lead Engineer
Project Engineering

Anthony L. Ruckriegel
Mgr. Contracts/Major Capital Projects
Project Engineering

R. Scott Straight
Dir. Project Engineering

John N. Voyles
VP Transmission & Generation Services

Paul W. Thompson
Chief Operating Officer

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chief Executive Officer

Arbough

Investment Proposal for Investment Committee Meeting on: September 28, 2016

Project Name: Network Management System Upgrade

Total Expenditures: $1,200k   (Including $158k of contingency)

Project Number(s): IT0077L, IT0077K, IT0077CG

Business Unit/Line of Business: Electric Distribution Operation / Information Technology

Prepared/Presented By: Steve Woodworth / Jason Jones

Executive Summary

EDO (Electric Distribution Operations) and IT (Information Technology) request funding to upgrade the existing ▌▌▌ NMS (Network Management System). The upgrade is driven by the requirement to keep the software version current to ensure continued vendor support. The ▌▌▌ NMS is a critical corporate system, essential for managing the electric restoration process. The NMS also provides data, such as ERTs (Estimated Restoration Times), to customer-facing systems like the IVRU (Interactive Voice Response Unit), Outage Maps, and smartphone applications.

The upgrade is included in 2017 in the approved 2016 Business Plan (BP) for $1,000K. However, the ▌▌▌ NMS is recommended to be the solution for DMS (Distribution Management System) to support DA (Distribution Automation). Since the outage functionality to be upgraded and the distribution management functionality to be implemented are in the same system, the two projects should be aligned.

EDO recommends the Investment Committee approve the NMS Upgrade Project for the capital cost of $1,200K ($250K in 2016, $700K in 2017, $250K in 2018) including a 10% contingency on vendor services for $38K and a 20% contingency on internal labor for $120K. The funding request has been approved by the Technology Portfolio Management Committee (TPMC) as well as the Corporate RAC in the July 2016 meeting. There is no on-going O&M.

Background

The NMS was last upgraded in 2013 and is currently on v1.11.0.4. ▌▌▌▌▌▌ ▌▌▌ for v1.11 ended in July 2016, but the Extended Support Program is available through July 2019. Starting the upgrade now will ensure completion prior to the end of ▌▌▌ Extended Support Program. In addition to support implications, the timing of the project has been adjusted to support the DA (Distribution Automation) Program. For the DA Program to achieve its expected electric reliability benefits, the DMS (Distribution Management System) modules of the NMS are required. The DMS modules will be installed with this upgrade.

- **Alternatives Considered**
    1. Recommendation: NPVRR: $1,340K
    2. Alternative #1: Do nothing   NPVRR: N/A

Alternative #1: Do Nothing:

The Do Nothing alternative would be to stay on the current ▮▮▮▮ NMS version and allow support to expire or switch vendors.

Staying on the current version is not a reasonable option because it would put a critical system at risk. Failure of the ▮▮▮▮ NMS would have a significant negative impact on the restoration process and the customer experience. In addition, it would limit LKE's ability to leverage the advanced distribution management functionality reducing the reliability benefits expected from DA.

Switching vendors is not a viable option for a number of reasons. First, it would be cost prohibitive. Replacing the ▮▮▮▮ NMS would cost approximately $10M - $12M. Secondly, ▮▮▮▮ is an industry leader in this space. No additional functionality would be gained. Finally, the decision has recently been made to expand the use of the NMS to include implementation of the DMS modules to support DA. This decision was made through the competitive bid process. Replacing the ▮▮▮▮ NMS would require reassessing the DMS decision and delay the electric reliability benefits of the DA Program.

Project Description

- **Project Scope and Timeline**
    - **Project Scope**
        - Upgrade the ▮▮▮▮ NMS to the latest version
        - Replace the existing, custom Smallworld GIS extractor with the standard ▮▮▮▮ extractor.
        - Automate the Smallworld GIS extractor process.
        - Implement integration to distribution SCADA.
        - Enable DMS modules.
        - Train users.

    - **Project Schedule/ Milestones**
        - Project Start: October 2016
        - Development Complete: December 2017
        - Testing Complete: June 2018
        - Go-Live: July 2018

- **Project Cost**
    - $1,200K
        - $250K in 2016

- $700K in 2017
- $250K in 2018
  - Includes a 10% contingency on vendor services and a 20% contingency on internal labor.
  - Includes $382K for outside services to be managed on time & materials basis.

Economic Analysis and Risks

- **Bid Summary**
  This is a sole source item. As the product vendor, ▮▮▮▮ is the only viable option to perform the upgrade.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	250	700	250	-	1,200
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	250	700	250	-	1,200
4. Capital Investment 2016 BP	-	1,000	-	-	1,000
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	1,000	-	-	1,000
7. Capital Investment variance to BP (4-1)	(250)	300	(250)	-	(200)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(250)	300	(250)	-	(200)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-

The incremental funding has been approved by the TPMC and RAC processes.

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Labor:	$660
Contract Labor:	$382
Materials:	$0
Local Engineering:	$0
Burdens:	$0
Contingency:	$158
Reimbursements:	($0)
Net Capital Expenditure:	$1,200

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	-	31.00	129.00	44.00	32.00	262.00
Project ROE	0.00%	4.90%	14.90%	17.00%	9.90%	11.80%

- **Assumptions**
  Not applicable.

- **Environmental**
  Not applicable.

- **Risks**
  o Failing to continue vendor support for the ▮▮▮▮ NMS will put the restoration process at risk.
  o The timing of the project is to maximize synergies between this project and the DA project. Completing the project outside of the proposed timeframe will negatively impact the expected reliability benefits of the DA project.

Conclusions and Recommendation   Arbough

EDO recommends Investment Committee authorization of $1,200K ($250K in 2016, $700K in 2017, $250K in 2018), including a 10% contingency on vendor services and a 20% contingency on internal labor, for the NMS Upgrade Project.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: July 31, 2018

Project Name: Pad Mount Meter Replacement

Total Approved Expenditures: $1,800k (Approved on 12/08/2017)

Total Revised Expenditures: $2,666k

Project Number(s): 406000003

Business Unit/Line of Business: Gas Distribution Operations

Prepared/Presented By: Lesley Hill/Tom Rieth

Background

Louisville Gas and Electric started a program in 2017 to replace all pad mount and AL-1400 gas meters currently in service over seven and a half years. At the beginning of 2018, approximately 650 pad meters and 50 AL-1400 meters remained in service, most of which serve commercial and industrial customers.

Unlike the common hanging diaphragm meters, pad meters are not simply replaced after a certain period, but are recertified (tested) and left in place. As a result, some pad meters have been in service since the 1950s. Pad meters are randomly selected and recertified as part of a Kentucky Public Service Commission requirement. If a meter is unsuccessful in the recertification process, the assembly must be removed and sent off to a meter remanufacturer. As the meters age, more are failing the recertification process, resulting in more being remanufactured. Due to the age of the meters, the availability of the parts needed to remanufacture the meters is decreasing. This in turn increases the price to remanufacture the meter and the time involved in the remanufacturing process. This combination of an increasing number of meters failing the recertification process, along with increasing costs to keep the meters in service, has led Gas Engineering to request this project.

The meters included in this project will be replaced with a rotary meter set or large commercial diaphragm meter (typically an AL-1000), and appropriate meter loop and regulator. Target meter sets on this project are usually replaced entirely with new meter sets, but occasionally involve modifications to the existing piping.

This project will replace approximately 100 pad mount meters in 2018. Annual projects are also currently planned for 2019-2024, replacing approximately 100 pad mount meters per year. Approval will be requested annually for each new project.

Pad meters are located throughout LG&E's service area. Approximately 85% of the 700 Although meters are within Jefferson County, and 15% spread throughout the rest of the service area. The majority of total meters will be replaced with AL-1000 diaphragm meters (59%), with the remainder being replaced with 3M (38%) or larger (3%) rotary meters. We expect the annual percentages to mirror the total project makeup.

This project also covers replacing existing medium pressure steel customer services as they are encountered with plastic services, and replacement of high pressure farm taps or meter loops. Service replacement is in conjunction with the service replacement project (#CRSS414) approved to begin in 2018, and is consistent with service replacement parameters used by that project. This will help aid in the customer experience by only having to interrupt their gas service once, versus multiple times for different projects. Approximately 75% of the meter replacements will require service work.

Reason for Revision

The 2018 Pad Meter Replacement project was approved in December 2017 for $1,800k. See attached original proposal. The revised estimated cost for 2018 is $2,666k. The 2018 Business Plan (BP) included $1,996k for this project, and was revised to $1,800k in the January 2018 RAC. The amount is now being adjusted due to higher cost of replacing steel services included in the project. The initial estimate of $1,800k was based on costs incurred in 2017. In 2017, only 10% of the meters replaced required service replacement, which made the overall project cost lower. In 2018, 75% of the meters replaced require service work, which matches the original project estimate. The remainder of the 2018 forecast is being adjusted to reflect the actual costs incurred by replacing 75% of the customer services. The Corporate RAC has approved the incremental 2018 funding.

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.32%	6.59%	
Capital Breakdown:			
Labor:	$ 130	$ 155	
Contract Labor:	$ 779	$1,257	More service replacements and higher cost per service.
Materials:	$ 510	$ 810	More service replacements.
Local Engineering:	$ 57	$ 98	
Burdens:	$ 160	$ 194	
Contingency:	$ 164	$ 152	5% of remaining forecast.
Reimbursements:	($ 0)	($ 0)	
Net Capital Expenditure:	$1,800	$2,666	
NPVRR:	$2,400	$3,464	

Financial Detail by Year - Capital ($000s)	Pre-2018	2018	2019	Post Through 2019	Total
1. Capital Investment Proposed	-	2,591	-	-	2,591
2. Cost of Removal Proposed	-	75	-	-	75
3. Total Capital and Removal Proposed (1+2)	-	2,666	-	-	2,666
4. Capital Investment 2018 BP	-	1,996	-	-	1,996
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	-	1,996	-	-	1,996
7. Capital Investment variance to BP (4-1)	-	(595)	-	-	(595)
8. Cost of Removal variance to BP (5-2)	-	(75)	-	-	(75)
9. Total Capital and Removal variance to BP (6-3)	-	(670)	-	-	(670)

Financial Detail by Year - O&M ($000s)	Pre-2018	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

The project is included in the June Corporate RAC forecast.

Conclusions and Recommendation **Arbough**

It is recommended that the Investment Committee approve the Pad Mount Meter Replacement project for $2,666k to replace pad mount meters and steel customer services with minimal interruption to customers.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Attachment 1

Investment Proposal for Investment Committee Meeting on: <u>N/A</u>

Project Name: <u>Pad Mount Meter Replacement</u>

Total Expenditures: <u>$1,800k</u>   (Including $164k of contingency)

Project Number(s): <u>406000003</u>

Business Unit/Line of Business: <u>Gas Distribution Operations</u>

Prepared/Presented By: <u>Lesley Hill</u>

Executive Summary

Louisville Gas and Electric started a program in 2017 to replace all pad mount and AL-1400 gas meters currently in service over seven and a half years. In 2018, approximately 700 pad meters will remain in service, most of which serve commercial and industrial customers. The meters included in this project will be replaced with a rotary meter set or large commercial diaphragm meter (typically an AL-1000), and appropriate meter loop and regulator. Target meter sets on this project are usually replaced entirely with new meter sets, but occasionally involve modifications to the existing piping.

This project will replace approximately 100 pad mount meters in 2018. Annual projects are also currently planned for 2019-2024, replacing approximately 100 pad mount meters per year. Approval will be requested annually for each new project.

Pad meters are located throughout LG&E's service area. Approximately 85% of the 700 total meters are within Jefferson County, and 15% spread throughout the rest of the service area.

The majority of total meters will be replaced with AL-1000 diaphragm meters (59%), with the remainder being replaced with 3M (38%) or larger (3%) rotary meters. We expect the annual percentages to mirror the total project makeup.

This project will also cover replacing existing medium pressure steel customer services as they are encountered with plastic services, and replacement of high pressure farm taps or meter loops. Service replacement is in conjunction with the service replacement project (#CRSS414) approved to begin in 2018, and is consistent with service replacement parameters used by that project. This will help aid in the customer experience by only having to interrupt their gas service once, versus multiple times for different projects. Approximately 75% of the meter replacements will require service work.

The estimated cost for 2018 is $1,800k. The proposed 2018 Business Plan (BP) includes Arbough $1,996k for this project. The forecast will be adjusted for the revised lower cost in the January Corporate RAC process.

Background

This is a continuation of the term program for retirement of existing pad meters (#3, #4, and #10) from service. These meters will be replaced by either rotary style meters or large diaphragm meters. There will be approximately 700 pad meters in service after 2017, most of which supply larger commercial customers.

Unlike the common hanging diaphragm meters, pad meters are not simply replaced after a certain period, but are recertified (tested) and left in place. As a result, some pad meters have been in service since– 1955 (#3), –1937 (#4), and –1960 (#10). Pad meters are randomly selected and recertified as part of a Kentucky Public Service Commission requirement. The #3 gas meters have a 10 year recertification period, while #4 and #10 gas meters have a 5 year recertification period. All meters of a certain style must be tested within that period. If a meter is unsuccessful in the recertification process, the assembly must be removed and sent off to a meter remanufacturer. As the meters age, more are failing the recertification process, resulting in more being remanufactured.

Over the years, a large number of these older pad meters may end up becoming inactive, or incorrectly sized for the current loading. These periods of inactivity or underutilization can result in increased stiffness in the diaphragms and linkages, and allow moisture and other contaminants to collect inside the meter, both of which can adversely affect the recertification testing and cause more meters to fail. This can also affect the accuracy of the meters, leading to lost and unaccounted for gas, rebilling, and in turn, negatively affect the customer experience.

Due to the age of the meters, the availability of the parts needed for remanufacture is decreasing, because the meters are becoming obsolete. This in turn increases the price to remanufacture the meter and the time involved in the remanufacturing process.

This combination of an increasing number of meters failing the recertification process, along with increasing costs to keep the meters in service, has led Gas Engineering to request this project.

LG&E has had two programs that helped reduce the number of pad meters in service over the last several years - Gas Main Replacement and Riser Replacement Programs. Both of these programs are on schedule to end in 2017. If the current pace of meter removal continues, (which is unlikely considering the two existing programs will soon end) it will be another 10 years before these meters are eliminated.

Pad meters are also removed by the Gas Meter Shop (GMS), at a rate of approximately 25 meters per year. GMS replaces pad mount meters when they are identified through the recertification process as causing potential safety hazards. Going forward, GMS will provide a list of pad mount meters they plan to test each year so those meters can be replaced on this project. That will eliminate any duplication of efforts.

- **Alternatives Considered**
    1. Recommendation: NPVRR: $2,400k
    2. Do Nothing: NPVRR: N/A
       This is not a viable option for reasons mentioned in the project background section. These meters will become more and more expensive to maintain, requiring more cost for parts, along with more manpower to test and repair. Leaving these meters in place would also affect negatively the customer experience. Failing meters increase the possibility of having to rebill customers for incorrect gas usage.

Project Description

- **Project Scope and Timeline**
  This project will replace 100 pad mount gas meters in 2018 with equivalent rotary or diaphragm meters. These replacement meters are the current standard meters used by the Company.

  Engineering has analyzed gas usage data from current pad meter customers in order to estimate the replacement meter types and sizes for this project, and the associated meter costs.

  Replacement will take place year round.

- **Project Cost**
  The 2018 estimated project cost is $1,800k, which includes a 10% contingency. The contingency amount was based on previous project experience, and will be used to cover variation in contract labor and miscellaneous costs, including but not limited to restoration costs, traffic control, and expenses due to meter locations such as taps under pavement or inside of buildings.

Economic Analysis and Risks

- **Bid Summary**
  The construction portion of the project was bid to eight vendors, both local and non-local. Of those eight, six companies chose to bid the project. The bids covered the entire program through 2024. It was chosen to bid the entire duration of the project in order to procure the best pricing. The terms and conditions of the labor contract allow the company to terminate the contract with thirty days' notice, if that becomes necessary during the life of the project. If that becomes necessary, the labor will be bid again.

  The project was awarded to ███████████████████ in 2017, who was the lowest bidder and is also very experienced performing this type of work for LG&E. Please see bid summary below. Materials have been purchased under existing blanket contracts and under new contracts.

%	Category	Weight	
Project:	**Pad Mount Meter Replacement**		
Date:	03/20/17		
%	**Category**	**Weight**	
	WBE/MBE/VOB/Small/Large		
	Union?		
	NAICS Code		
5%	**Completeness of Bid Submittal**		
	All required attachments submitted	2.50	
	Clarifications/Exceptions clearly stated	2.50	
P/F	**Safety/Risk Management**		
	Safety Record (EMR / Recordables) Safety Plan	P/F	
75%	**Commercial**		
	Pricing - Base Case (75* ratio to low bidder)	75.00	
20%	**Value Added**		
	Previous Company Experience (Y/N)	10.00	
	Previous Company Satisfaction Score	10.00	
100%	**Total(s)**	**100**	
	Bid Cost Summary Detail		
	Blended Rate - 5/10's *-85% of total year*		
	Extended Rate -Saturday		
	Outside of Jeff Co. Crew Rate *-15% of total year*		
	Welder Rate		
	Welder OT Rate		
	Rate Adjustment		
	Sewer Inspection Markup		
	Sewer Inspection Pricing *(Self performed)*		
Includes Saturday Work at 50% of the year & Welder at 85% of Time	Total Estimated Annual Cost -2017		
	Total Estimated Annual Cost -2018		
	Total Estimated Annual Cost -2019		
	Total Estimated Annual Cost -2020		
	Total Estimated Annual Cost -2021		
	Total Estimated Annual Cost -2022		
	Total Estimated Annual Cost -2023		
	Total Estimated Annual Cost -2024		
	Total Estimated Project Cost		
	Delta to low bidder's price		
	Price ratio to low bidder's price		
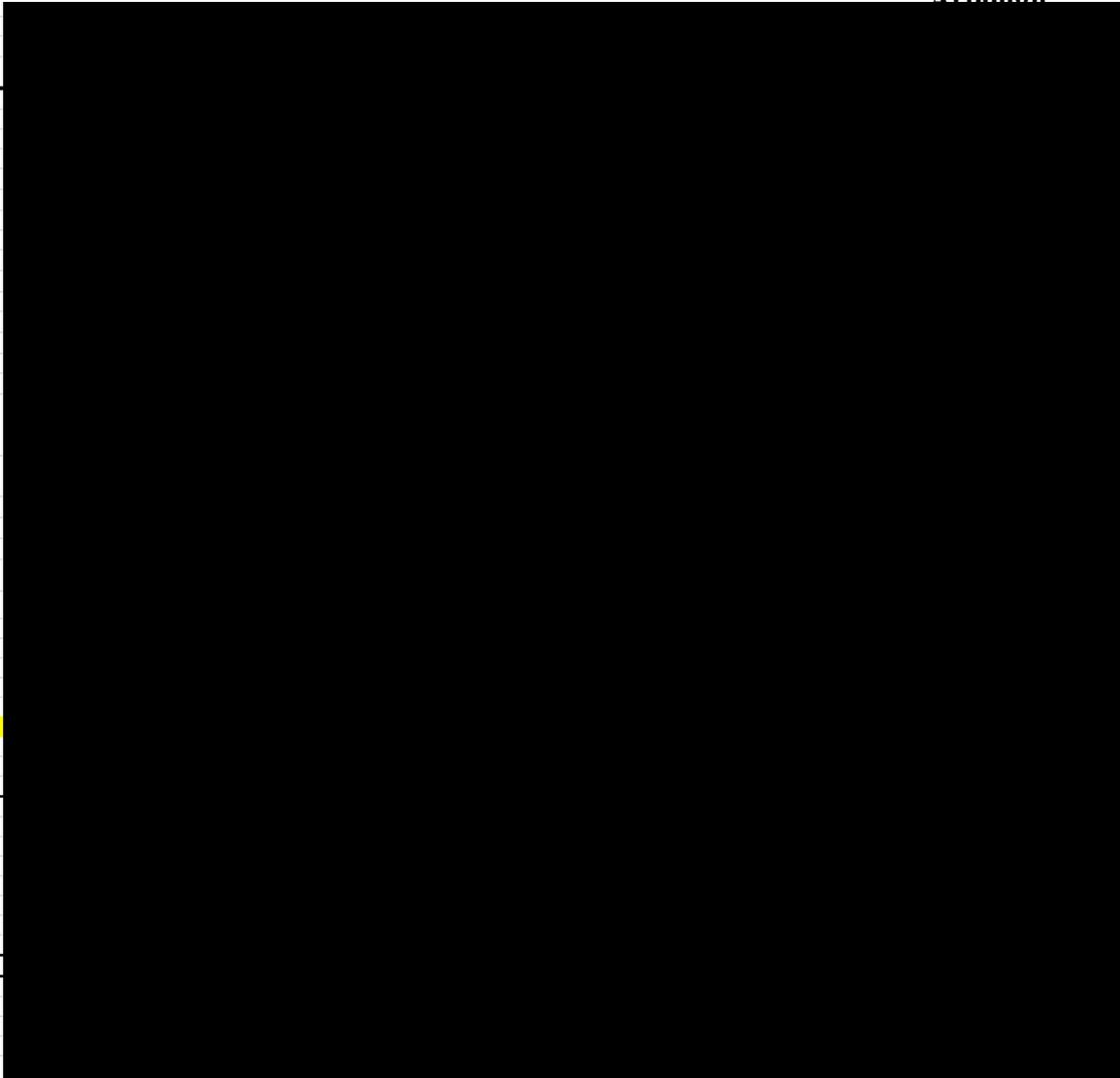
- **Budget Comparison and Financial Summary**   Arbough

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	1,750	-	-	-	1,750
2. Cost of Removal Proposed	50	-	-	-	50
3. Total Capital and Removal Proposed (1+2)	1,800	-	-	-	1,800
4. Capital Investment 2018 BP	1,996	-	-	-	1,996
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,996	-	-	-	1,996
7. Capital Investment variance to BP (4-1)	246	-	-	-	246
8. Cost of Removal variance to BP (5-2)	(50)	-	-	-	(50)
9. Total Capital and Removal variance to BP (6-3)	196	-	-	-	196

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project is included in the proposed 2018 BP. The 2018 forecast will be adjusted through the Corporate RAC process to reflect the current estimate of $1,800k, which is lower than the proposed 2018 BP amount.

Financial Summary ($000s):

Discount Rate:	6.32%
Capital Breakdown:	
Labor:	$ 130
Contract Labor:	$ 779
Materials:	$ 510
Local Engineering:	$ 57
Burdens:	$ 160
Contingency:	$ 164
Reimbursements:	($ 0)
Net Capital Expenditure:	$1,800

- **Assumptions**
  - Capital expenditures were estimated in part using historical data. Non-construction contractor costs (materials, restoration, traffic control, locates, etc.) were assumed to be consistent and proportional with current programs.

- **Environmental**
  This project does not include any major environmental requirements.

- **Risks**

  Risks of not completing this project include increased company labor and materials costs associated with the maintenance of existing pad meters, and decreased customer satisfaction due to billing inaccuracies.

Conclusions and Recommendation

It is recommended that Management approve the Pad Mount Meter Replacement project for $1,800k to replace existing pad mounted meters.

Investment Proposal for Investment Committee Meeting on: June 28, 2017

Project Name: Paynes Mill Substation Project

Total Expenditures: $7,234k (includes $344k contingency)

Project Number: Distribution-152860, Substation-138168, Transmission-134256

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tim Smith/Kevin Patterson

Executive Summary
Electric Distribution Operations (EDO) - Electric Engineering and Planning seeks funding authority for the construction of a new 37.3MVA distribution substation to be located at the intersection of US 60 and Paynes Mill Road in Versailles, Ky. The additional capacity at Paynes Mill Substation is required to meet the electrical service needs of approximately 7,651 existing customers in the Versailles/Woodford County service area, as well as new developments proposed along US 60 in this high potential growth area in Woodford County. Electric service for this area is currently provided by extended distribution circuits from Alexander and Versailles Bypass 1 Substations. The current System Planning winter load forecast data base predicts that Alexander 12KV (22.4MVA) will reach 111% of its top nameplate capacity during the winter of 2019/2020 (assumes average winter temperature conditions) and Versailles Bypass 1 will reach 90% of its top nameplate. However several large customer proposals in various stages of project completion are expected to exacerbate the demand at Versailles Bypass 1 to a much higher than currently forecasted level. The expected winter demand at Versailles Bypass 1 due to new customer growth is anticipated to be 27.4MVA (122%) during the winter of 2019/2020 exceeding Distribution Planning's allowable winter loading limit of 120% of the transformer's nameplate rating. This project will address overloading issues at Versailles Bypass 1, improve transmission and distribution reliability in the area, and provide additional capacity to support new development. The additional transformer capacity from the proposed substation will also remove Alexander 12kV, Versailles Bypass 1 and Versailles Bypass 2 transformers from the Company's "Distribution Substation Transformer Contingency Program (N1DT)" list (transformers that cannot be fully backed up for a failure of a substation transformer during high load periods). Project completion is expected in December 2019.

Funding is requested in the amount of $7,234k to construct the new Paynes Mill 37.3MVA 69/12kV Substation. The 2017 Business Plan (BP) included $7,234k in 2017 and 2018 for this project. The project has now shifted to a 2018/2019 project with $1,210k spending in 2017 for major equipment.

Background   **Arbough**

Paynes Mill Substation will be located on the southeast corner of a 410 acre property in Versailles called Edgewood Farm. This property is located near the intersection of US 60 and Paynes Mill Road on the east side of Versailles, Ky. This general area was determined by Distribution System Planning models to be an optimal substation location to support developing load growth along US 60. In 2012, KU purchased 2.6 acres of land and associated utility easements for a new substation in the predetermined area. Load forecasts determined that future transformer capacity would be needed to relieve loading at surrounding substations that currently serve this area. Edgewood Farm, which is the property's official name and where the new substation will be located, is currently planned for development. There has been significant new growth in the area, including the largest Kroger store in the state, as well as multiple new retail and dining establishments. A large bakery and a hotel are currently under construction in the immediate vicinity. Officials for the City of Versailles have identified this location as ideal for development, and growth is expected to continue in this vicinity due to the many positive amenities such as available land for development, close proximity to major highways (US 60, and the Bluegrass Parkway), existing railway access (along the northern boundary), and easy access to Keeneland Race Track, Lexington Bluegrass Airport (both 6.6 miles to the east via US 60) and the city of Lexington.

The Versailles area 12kV distribution system is comprised of five existing substations: Alexander 12kV, Versailles Bypass (1 and 2), Versailles West and Shannon Run. Electric Distribution Operations has been managing new customer growth in the area by shifting loads to Versailles Bypass Substation as a short-term plan. This process reduces system reliability and has resulted in over 35MVA of load downstream of one 69kV switching point. Having exhausted all transfer options and circuit reconfigurations, Versailles Bypass 1 is anticipated to exceed it top winter rating during the winter of 2019/2020. The strategic location of the proposed substation will allow for approximately 15MVA of load to be shifted from Alexander 12kV and Versailles Bypass 1 Substations, relieving the projected overloads. The new developments planned along US 60 will be served from distribution circuits fed from the proposed Paynes Mill Substation. In addition to relieving expected overloads, providing capacity for new growth and improving area reliability, the additional capacity provided by this new substation will also remove Alexander 12kV, Versailles Bypass 1 and Versailles Bypass 2 transformers from the Company's N1DT Contingency Program List.

This project includes the construction of a new distribution substation with a 69/13.09kV 37.3MVA transformer in Versailles, Kentucky. Transmission improvements include a new transmission tap, line upgrades and line breakers which enhance the reliability of the 69kV line which feeds multiple substations. Because of the visibility of the station and its proximity to planned developments, the exterior of the station will include a split face block wall enclosure on three sides and high security fencing on the company accessible side. Distribution circuit improvements include three new underground distribution circuits to be extended from the substation to overhead feeder circuits along US 60. Once complete, load shifts will allow the new station to serve 2,134 of the 7,651 customers currently served by Alexander 12kV and Versailles Bypass 1 Substations.

A Network Integration Transmission Service (NITS) request was submitted to TranServ International to establish a new 69kV delivery point on October 25, 2016. No additional transmission improvements are expected beyond the cost to serve the new substation.

Alternatives Considered

1. Recommended Option: NPVRR: $8,240k
   The recommended option is to construct a new substation and 69kV transmission delivery point.

   Install a new 37.3MVA substation transformer with switchgear type breakers on substation property owned by KU near the intersection of US 60 and Paynes Mill Road. Install a 69kV transmission tap, three transmission line breakers, transformer breaker and three circuit breakers. Install three underground parallel 1000 kCM Aluminum distribution circuits from the substation to the new riser poles on US 60 to offload Alexander 12kV and Versailles Bypass 1 transformers. The estimated total cost of this option is $7,234k.

2. Do Nothing Option: NPVRR: N/A
   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating limits for distribution substation power transformers, and this practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1: Upgrade Versailles Bypass 1 Substation to 37.3MVA   NPVRR: $13,985k
   The alternative option considered was to replace the existing Versailles Bypass 1 Substation 22.4 MVA transformer with a 37.3 MVA transformer. This would require purchasing additional land to expand the substation and reconfiguring the single 69kV transmission tap feeding both transformers in the substation into separate taps for Versailles Bypass 1 and 2 transformers. Distribution work would require extending approximately 13,000' of new 795kCM Aluminum conductor feeder with a significant transmission under build to reach the areas where growth is expected. Based on expected developments in the area, a new substation (Paynes Mill) would still be required in 7-12 years. This alternative results in a less flexible and a less reliable system while providing less capacity for future growth. This option will remove only the Versailles Bypass 2 transformer from the Company's N1DT Contingency Program List. Planning studies indicate an outage of the Versailles Bypass 2 transformer at peak would cause as much as 3,888kW of load to go unserved and the loss of the Alexander 12kV transformer would cause as much as 6,732kW of load to go unserved. Using the corporate "Cost of Unserved Energy" ($17.2/kWh) with estimated load at risk going unserved at peak for 24 hours, the Cost of Unserved Energy would total $4,384k. While the loss of a substation transformer is a relatively low probability event in any given year, the estimated annualized Cost of Unserved Energy based on an annual 5% probability of an outage on either transformer is $219k.

   The estimated capital cost for this option is $8,442k (2018 - $4,670k, 2019 – $3,772k).

Project Description

Project Scope
- Transmission project #134256: estimated cost $1,104k ($397k-2018, $707k-2019)
  - Install transmission poles for a tap for a new 69kV delivery point on the Tyrone 65 to Pisgah 210 69kV line on US 60 to the Paynes Mill Substation. Install a 400' double circuit 69kV tap into the proposed Paynes Mill Substation from US 60.

- Substation project #138168: estimated cost $5,630k ($1,210k-2017, $920k-2018 $3,500k-through-2019)
  - Perform a geotechnical survey, site prep and service road construction needed for the development of this "greenfield" site that previously has been used for agriculture. Install a 14 foot high split face decorative block wall enclosure on three sides with a wrought iron fence on the accessible side. Install one 69/13.09 kV, 37.3MVA substation transformer, transmission line breakers, transformer breakers and associated switchgear type breakers, steel structure, control house, SCADA communications and associated equipment.
- Distribution project #152860: estimated cost $500k (in 2019)
  - Install a 6" underground duct bank (approximately 1,600') and manhole system for three new distribution circuits. Install six three-phase cable sets (2 per circuit) of 1000kCM Aluminum exit circuits and three electronic reclosers to complete circuit ties.

- **Project Timeline**
  - July 2017: Open project
  - July-December 2017: Order and accrue 2017 portion of the cost of the substation transformer and switchgear.
  - 1st Qtr. 2018: Complete transmission, substation and distribution engineering design. Take delivery of substation transformer and switchgear.
  - 2nd Qtr. 2018: Complete material and equipment orders for transmission, substation and distribution, complete geotechnical survey of property.
  - May-December 2018: Install service road, site prep, wall construction, fencing footers and concrete piers.
  - November 2018-January 2019 final engineering, protection scheme settings, relay settings, and circuit coordination.
  - January 2019: Begin transmission and distribution circuit construction.
  - April 2019: Take delivery of long lead items, including transmission poles, substation control house, steel package and distribution cable.
  - April-October 2019: Install substation transformer, switchgear and SCADA communications.
  - November-December 2019: Site cleanup, landscaping, system check out and commissioning.

- **Project Cost**
  The total estimated cost of the project is $7,234k. The substation and transmission line cost estimates are consistent with the "Conceptual level 1" engineering design designation. The distribution cost estimate is consistent with the "preliminary" engineering design designation and is based on field experience from similar projects. There is an estimated 5% of contingency ($344k) incorporated into the project cost estimates.

Economic Analysis and Risks
- **Bid Summary**
  - Substation Engineering and Design will use established Engineering Procurement and Construction Management (EPCM) contracts to augment engineering and construction management resources as required.
  - The substation transformer, steel package and transmission poles will be bid using established Supply Chain procedures.

- Substation Construction and Maintenance (SC&M), Distribution Operations, and Arbough Transmission Lines will use existing material and labor contracts and follow established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	1,210	1,317	4,674	-	7,201
2. Cost of Removal Proposed	-		33	-	33
3. Total Capital and Removal Proposed (1+2)	1,210	1,317	4,707	-	7,234
4. Capital Investment 2017 BP	2,743	4,474	-	-	7,217
5. Cost of Removal 2017 BP	-	17	-	-	17
6. Total Capital and Removal 2017 BP (4+5)	2,743	4,491	-	-	7,234
7. Capital Investment variance to BP (4-1)	1,533	3,157	(4,674)	-	16
8. Cost of Removal variance to BP (5-2)	-	17	(33)	-	(16)
9. Total Capital and Removal variance to BP (6-3)	1,533	3,174	(4,707)	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The timing changes between years have been adjusted through the Corporate RAC process for 2017 and will be adjusted in the 2018 BP process.

Financial Summary ($000s):

Discount Rate: 6.5%
Capital Breakdown:
   Labor: $ 502
   Contract Labor: $2,789
   Materials: $2,334
   Local Engineering: $ 658
   Burdens: $ 521
   Transportation: $ 86
   Contingency: $ 344
   Reimbursements: ($ 0)
   Net Capital Expenditure: $7,234

- **Assumptions**
  - Substation load demands will be in line with the company's distribution System Planning load forecast.
  - Project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution facilities are consistent with similar past projects.
  - No significant unknown costs for transmission improvements will be associated with the addition of a new service point.
  - The project will be completed by December 2019.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**
  Failure to complete this substation project before the winter of 2019/2020 will result in declining reliability for the Versailles area and substation transformer loading above normal operating limits escalating the potential for failure of the Versailles Bypass 1 or Alexander 12kV Substation transformers. Load restriction could result in an inability to serve new development in the Versailles area.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the Paynes Mill Substation Project to build a new 37.3MVA substation for $7,234k to serve existing customers and new development in Versailles, Kentucky.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: December 19, 2018

Project Name: PC Tech Refresh

Total Expenditures: $2,485k

Project Number(s): IT0477B

Business Unit/Line of Business: IT

Prepared/Presented By: Jeff Smith / Priya Mukundan

Executive Summary

LGE KU Energy (LKE) implemented a program in 2002 to replace desktops and laptops on a three-year cycle. The program was reevaluated in 2005 and it was determined then that the refresh cycle could be extended to four years for desktop computers. In 2017, the decision was made to begin refreshing laptop computers on the same four year cycle due to advancements in technology, improved reliability and better warranties. The replacement cycle is consistent with industry norms as confirmed by Gartner, an American research and advisory firm that provides technology related insights to businesses.

The refresh process has continued to evolve over the years through various means. The 2019 Technology Refresh budget was reduced from its original budgeted amount by approximately $500k, with the savings attributed to thin client placement, reduction of the number of devices an individual may have, and placing the appropriate device into production. LKE continues to deploy thin client technology, which extends the rotation cycle to an estimated 6 years. During the Tech Refresh process, devices are assessed for possible conversion with more than 500 thin clients currently deployed. Because we have hit some limits on the number of desktops that we can convert to thin clients, we have adopted a new strategy with the use of Chromebooks which run the Chrome OS. These can be viewed as mobile thin clients and will allow us to further target reductions in laptops (which is the largest segment of machines). This strategy is a reduction in both capital purchase as well as ongoing O&M.

In addition to the desktop and laptop refreshment, LKE also refreshes ruggedized Toughbooks on a 4 year rotation. These are devices placed into service in 2015 and earlier for Electric and Gas Operations business. In 2019, some of these devices will be refreshed as part of the normal process while others will begin transitioning to iPad or other lower cost devices. This project is included in the 2019BP for $2,485k.

Background

This project is the continuation of current IT policy to provide upgrades to the workstation infrastructure and will include implementation of the new Windows 10 operating system and deployment throughout the organization. The project will provide the rotation of approximately 1410 new desktops, laptops and Toughbooks into the environment in 2019. The project maximizes operating efficiency for our knowledge workers and keeps IT support costs from increasing due to unplanned hardware maintenance.

- **Alternatives Considered**

    Recommendation for 2019 Refresh Project   NPVRR: $2,663K
    - Positive impact on business operations for 2019
    - Windows 10 will be deployed to all devices
    - Keep pace with advancing technology
    - Minimize risk to O&M budgets for repairs
    - Ability to rollout new applications required by the lines of business

    Alternative 1 "Do Nothing"
    - Negative impact on business operations for 2019   NPVRR: N/A
    - Not keeping pace with advancing technology
    - Risk to O&M budgets for repairs
    - Inability to rollout Windows 10 and other new applications required by the lines of business
    - This is not considered a viable long-term option because it poses productivity and down-time risks to operational areas dependent on the technology being updated.

    Alternative 2 "Defer Project"   NPVRR: N/A
    - Same as Alternative 1 "Do Nothing" and not considered a viable alternative
    - Schedule impact for rollout of new applications to lines of business

    Alternative 3 "Replace only failed equipment"   NPVRR: N/A
    - Same as Alternative 1 "Do Nothing" and not considered a viable alternative
    - Adverse effects to rolling out new applications required by the lines of business
    - Productivity impact and "down-time" for clients when equipment fails

    Alternative 4 "Extend rotation period to 5 years"   NPVRR: N/A
    - Same as Alternative 1 "Do Nothing" and not considered a viable alternative
    - Productivity impact and "down-time" for clients when equipment fails
    - Extended rotation cycle is not consistent with Gartner recommendation

Project Description

- **Project Scope and Timeline**

This project will evaluate and replace four year old desktops and laptops in 2019 before the computers experience hardware issues that cause out of warranty repair and unnecessary client down time. The project will be completed by 12/31/2019. All LKE desktops, laptops, and Toughbooks that were purchased in 2015 (and earlier) will be evaluated for replacement. Where possible, thin clients or Chromebooks will be used for replacements. The replacement schedule will be determined by site and will be reported monthly through departmental status reports. The project is budgeted and there are no incremental O&M expenditures or savings related to the project. There are avoided costs associated with this project including improved reliability, reduced downtime for clients, and out of warranty repair costs, etc.

Economic Analysis and Risks

- **Bid Summary**

The hardware for this project will be purchased under the PC Hardware and Peripherals Contract to ▮▮▮▮. In 2016, PPL and LKE issued a joint bid seeking a larger volume discount and synchronized the PA and KY contracts. ▮▮▮▮ was awarded the supplier contract for both PPL and LKE through a competitive bid process that included Minority-Owned and Woman-Owned businesses. ▮▮ was awarded the hardware contract for both PPL and LKE, and both companies will purchase the ▮▮ hardware through the ▮▮▮ supplier contract.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	2,485		-	-	2,485
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	2,485		-	-	2,485
4. Capital Investment 2019 BP	2,485	-	-	-	2,485
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	2,485	-	-	-	2,485
7. Capital Investment variance to BP (4-1)	-		-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$401
Contract Labor:	$432
Materials:	$1,652
Local Engineering:	$0
Burdens:	$0
Contingency:	$0
Reimbursements:	($0)
Net Capital Expenditure:	$2,485

- **Assumptions**
  - Workstations will be available and delivered in 14 business days or less after order.
  - Cost per workstation will not shift dramatically during the year.
  - Contract labor will be available and no reduction of internal labor will occur.

- **Environmental**
  No environmental impact.

- **Risks**
  If the project is not approved, the main risk would include aging hardware that could fail that would create disruptions to individuals and processes. It would also hinder our ability to complete our Windows 10 migration by the hard deadline of end of year 2019 due to not having enough refresh machines to complete the process. Hardware replacement after failure would be expected to be more costly than replacing prior to failure, along with the negative productivity impact to employees that experience unplanned hardware failure.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the 2019 PC Tech Refresh project for
$2,485k to ensure that our workstation environment meets the needs of the operational areas who
are dependent upon the tools and technology to do their job.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the
members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the
signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: November 28, 2018

Project Name: LGE PILC UG Network Cable Replacement Program-2019

Total Expenditures: $11.949M   (includes no contingency)

Project Number(s): 151486

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton / Shawn Stickler

Executive Summary

Electric Distribution Operations (EDO) proposes to invest $11.949M in 2019 towards the continuation of the PILC Cable Replacement Program. The program was initiated in 2013, and involves replacement of bare (unjacketed), paper insulated, lead covered (PILC) low voltage (LV) secondary and medium voltage (MV) primary cables operating in the downtown Louisville network distribution system. The program places replacement priority on secondary cable sections, and provides for necessary reconstruction or replacement of any discovered defective duct lines and manhole structures. The Program is included in the proposed 2019 Business Plan (BP) funded at $11.949M. The $11.949M includes $1.1M to meet enhanced street resurfacing requirements imposed in 2017 by Louisville Metro Public Works.

This program originally was anticipated to span 11 years and conclude in 2023. The total 11-year program cost, originally projected at $62M (2013 dollars), is expected to reach an estimated $74.739M by program completion. Additionally, EDO is accelerating the PILC program from 11 years to 9 years (2013-2021). The remaining program requires a 3-year (2019-2021) capital investment of approximately $33.867M. This will yield replacement of approximately 31 miles of cable in the remaining three years of the program. Actual amounts in any year will vary based on the mix of cable replacement, duct replacement, and manhole work. The higher than expected rate of defective duct line replacement has been partially offset by improved cable replacement efficiencies during the cable installation and removal processes.

PILC Network Cable Replacement Program	2019	2020	2021
PILC Cable Replacement ($000s)	10,849	10,550	9,163
PILC Cable Replacement - Curb to Curb Paving ($000s)	1,100	1,100	1,100
Cable Replacement Targets (Miles)	10.5	10.5	10

Projected program costs are reevaluated annually as additional data becomes available to better quantify the amount of PILC cable in the network and the condition of ducts and manholes.

Background

LG&E operates five separate secondary network systems with 27 circuits within the core downtown Louisville business and medical districts, roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south), and 8th Street (west). Three of the five network systems, served by the Waterside, Magazine, and Madison Substations, contain bare PILC cables. All primary and secondary conductors in main thoroughfares are completely underground and installed in manhole and duct systems.

Network distribution systems were developed in the early 1910's in order to provide the highest degree of service reliability to downtown business districts and to facilitate service to densely populated areas desiring a totally underground distribution system. The original LG&E network was built using PILC cables, constructed of oil impregnated paper tape insulations and jacketed with a bare lead sheath, the most reliable cable construction available at the time. At the beginning of this program, an estimated 70 miles of bare primary and secondary PILC cables, ranging in age from 48 to 100 years old, were in service in the downtown Louisville network distribution system.

Early PILC primary cables and all PILC secondary cables utilized bare lead sheaths that have experienced varying degrees of surface corrosion over their service lives. Corrosion and/or mechanical damage allow the insulating oil to leak from the insulation and allow water to enter the cable, ultimately leading to a cable failure. Insulating oils in the older bare PILC cables are also reportedly much drier than when newly manufactured, indicating the degree of insulation aging and degradation. While service from the downtown network is designed for high reliability, and the number of cable failures is relatively small, primary PILC cable failure rates had shown an increasing trend over the past fifteen years and were failing at twice the average rate per mile as the rest of the LG&E and KU underground systems. Primary cable failures over the three consecutive five-year periods preceding program initiation increased from an average of 3.2 (1999-2003), to 5.6 (2004-2008), to 8.2 (2009-2013). Known secondary failures averaged approximately two each year and had significantly greater consequences than primary failures due to high fault currents, and because secondary cables are not protected against faults and must burn in the clear before a fault is extinguished. The increase in secondary cable burnouts, the documented primary cable failure incidence rate, and the risk posed to adjacent cables in the duct and manhole system highlights the need to continue replacement program funding to address secondary and primary PILC cables.

Under this program, PILC cables are replaced with the latest generation of solid dielectric cables using either rubber or crosslinked polyethylene insulation. The new cables are not subject to corrosion under wet conditions and will be more resistant to water ingress with aging. Current generation cables have a life expectancy of more than 50 years.

Since program initiation, asset field inventories of cable and duct line capacity assessments in the network continue to reveal that significant quantities of aged duct lines are collapsed and deteriorated, requiring the need for additional duct lines and manhole capacities. Thus far, during the program, additional PILC secondary cable failures have been found located out of sight within the duct line that had not yet propagated to the point of a violent burnout or loss of

customer service. Nearly all manholes encountered required replacement of cable support hardware and repositioning of fallen cables.

- **Alternatives Considered**

    1. Recommendation: NPVRR: ($000s) $15,153
        EDO recommends investing $11.949M during 2019 towards continuance of the PILC Cable Replacement Program to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system.
    2. Do Nothing: NPVRR: N/A
        While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it could occur if more than two circuits on the same network system containing PILC cable sustained failures to primary system components at the same time.   Failure to proceed with the bare PILC cable replacement program introduces growing risk for cable failures caused by increasingly aged PILC cables, which could result in a significant partial or total outage to one of Louisville's three downtown grid networks which contain PILC cable. The network could be partially or completely restored only after one or two of the failures were located and repaired, depending on loading. In addition, a lengthy network outage would severely impact downtown central business district customers comprised of metro and federal government agencies (police, security, traffic, etc.), judicial and legal systems, hospitals and medical offices, banking and investment institutions as well as other commercial businesses, including entertainment and tourism.
    3. Next Best Alternative(s):   NPVRR: N/A
        There are no alternatives to a traditional replacement program for extending the useful life of aged and deteriorating PILC cable systems and no reliable and/or practical method for testing the physical or electrical condition of bare PILC cable systems.

Project Description

- **Project Scope and Timeline**

    The 2019 PILC replacement project continues the planned removal and replacement of aged and deteriorating bare PILC secondary and primary cables in the downtown Louisville network distribution system including the projected replacement of more than 16,000 feet of damaged duct line. The project includes the replacement of cable and cable accessories (splices and terminations), the conversion of PILC terminated network transformers, and the necessary maintenance, additions and/or reconstruction of defective duct line and manhole structures. Funding also includes an expected increase in the cost of street restoration associated with duct replacement resulting from more stringent roadway repair requirements implemented by Louisville Metro. Requested 2019 funding allows for the replacement of a projected 10.5 miles of secondary and primary cable.

Electric Distribution attempts to prioritize and schedule PILC replacement based on **Arbough** pedestrian density, historical performance, and asset condition, subject to City of Louisville Public Works planning and permitting. Replacement priorities will focus on secondary PILC cable with bare lead jackets (installed between 1929 and the mid-1960's), followed by primary network cable with bare sheaths (installed between the mid-1910's and mid-1960's).

- **Project Cost**
  The 2019 proposed estimate for this work is $11.949M for duct line and manhole structures assessment, necessary structure additions and rebuilds, cable removal, installation and termination. No contingency is included in the projected cost.

- **Project Progress and Program Projection**
  The PILC Replacement program began in 2013 and is summarized in the following table:

Period (Project #)	Costs Applied (Budget)	Cable Circuit Miles Replaced	Duct line Ft Installed
2013 (#139271)	$1,990,597	1.65	820
2014 (#141195)	$5,833,931	6.57	4,110
2015 (#146442)	$6,050,569	7.07	7,353
2016 (#148497)	$6,274,861	7.24	5,236
2017 (#148739)	$9,290,788	8.27	11,530
2018 (#148899) *Estimated*	$11,333,000	10.5	16,000
2019 (#151486) *Proposed*	$11,949,000	10.5	18,000
Total Program 2013 thru 2019	$52,722,746	51.8	63,049

2019 Expectations:
   o Complete the last remaining portions of secondary grid replacement in the Madison network and shift replacement work to the Waterside grid. The Madison secondary is located in a highly congested area of the hospitals. LG&E is coordinating with the hospitals around this area.
   o Secondary work on Magazine grid complete except for lower priority PILC service and street light taps to be backlogged until the end of the secondary portion of the program.
   o Duct line replacement activity expected to increase above 2018 levels in response to finding significant duct line and manhole deterioration levels in the Network grid, predominantly in the Madison and Waterside networks.

Economic Analysis and Risks

- **Bid Summary**
  No special service contracts are required. The higher cost cable and connector materials are competitively bid and direct shipped to minimize inventory handling burdens.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	11,245				11,245
2. Cost of Removal Proposed	704				704
3. Total Capital and Removal Proposed (1+2)	11,949	-	-	-	11,949
4. Capital Investment 2019 BP	11,949				11,949
5. Cost of Removal 2019 BP					-
6. Total Capital and Removal 2019 BP (4+5)	11,949	-	-	-	11,949
7. Capital Investment variance to BP (4-1)	704	-	-	-	704
8. Cost of Removal variance to BP (5-2)	(704)	-	-	-	(704)
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed					-
2. Project O&M 2019 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 558
Contract Labor:	$ 5,898
Materials:	$ 3,576
Local Engineering:	$ 841
Burdens:	$ 852
Transportation:	$ 152
Miscellaneous:	$ 72
Contingency:	$ 0
Reimbursements:	($ 0)
Net Capital Expenditure:	$11,949

- **Assumptions**
  - Cost estimates are based on current knowledge of network assets. Asset quantities affected, costs, and project term will be adjusted as the project progresses.
  - Actual cable replacement quantities in 2019 are subject to net available project funding for cable replacements following necessary duct line and manhole structures work. Additionally, cable replacement quantities could also be affected if funding anticipated for enhanced street resurfacing requirements imposed by the Louisville Metro Council is insufficient.
  - Some work will be performed at night when necessary to minimize traffic congestion on downtown streets during daily business hours.

- **Environmental**

  No additional environmental issues are anticipated beyond the normal lead and cable oil handling and disposal requirements.

- **Risks**

  Failure to proceed with the bare PILC cable replacement program will incrementally increase risks to network system reliability. Delays could compress a planned multi-year replacement program into a shorter term, requiring greater annual manpower and funding levels to address system reliability.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the continuance of the PILC Replacement Project for $11.949M for 2019 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by the replacement of aged, defective, and deteriorating PILC cable and structural assets.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: <u>December 19, 2018</u>

Project Name: <u>Distribution Wood Pole Inspection and Maintenance Program - 2019</u>

Total Expenditures: <u>$12,278k</u>   (Including $246k of contingency)

Project Number(s): <u>LGE: 19PITP340, KU: 19PITP216, 19PITP156, 19PITP246, 19PITP315, 19PITP766, 19PITP416, 19PITP366, 19PITP236 and 19PITP426</u>

Business Unit/Line of Business: <u>Electric Distribution Operations / Distribution</u>

Prepared/Presented By: <u>John Ashton / Denise Simon</u>

Executive Summary

The Investment Committee approved the Electric Distribution Operations' Distribution Wood Pole Inspection and Maintenance Program on February 24, 2010, with the provision that future year investments in the program be presented and approved annually. The purpose of this Investment Proposal is to obtain 2019 program funding authority from the Investment Committee. The 2019 program scope is focused on providing a detailed pole inspection; preservative re-treatment and load analysis of approximately 65,000 poles and reinforcement or replacement of structures found to be defective. The program projections for 2019 include replacement of approximately 2,300 defective poles and reinforcement of 245 poles.

The other option considered is to only inspect on the 2-year KPSC required inspection cycle. This type of inspection is not rigorous enough to adequately identify at-risk poles, does not inspect for ground line rot and does not include pole loading calculations. Foregoing a pole inspection and treatment program dependent only on the regulatory cycle inspections will result in decreased life of the assets, increase pole failures and associated outages.

The 2019 Business Plan (BP) includes $12,278k for this program in 2019.

Background

The Distribution Wood Pole Inspection and Maintenance Program was implemented in 2010. By year end 2018, approximately 497,000 poles will have been inspected, 154,000 poles will have been treated, 19,000 poles will have been replaced and 1,400 poles will have been reinforced by splinting. Cumulative spend from 2010-2017 is $78.3 million with the 2018 forecasted spend at $11.9 million.

EDO has more than 516,000 distribution wood poles in the asset base with an estimated average age of 30 years. An additional 156,000 foreign-owned poles have LG&E and KU attachments.

Wood poles are initially treated with a preservative during processing to extend the life of the pole. The effectiveness of the initial preservative treatment declines with age. Wood poles become more susceptible to deterioration from fungal decay and insect damage. In most cases, the decay is difficult to detect because it occurs out of sight just below the ground-line where conditions of moisture, temperature and air are most favorable for growth of fungi. Ground-line is also the point of maximum loading stress for a pole.

In addition to the wood pole inspection program, distribution poles receive an inspection every two years in accordance with KPSC requirements. During these inspections, only a small percentage of poles are inspected near ground-line or tested to detect internal decay. No poles are excavated to inspect below ground-line which is critical for detecting decay. Continuing the wood pole inspection program as proposed will enhance the ability to detect decay and extend the life of the treated and reinforced poles.

A survey of utilities confirms that the industry typical program generally involves inspecting and applying a supplemental treatment to the ground-line area on every pole. The supplemental treatment arrests any decay present and can significantly increase the useful life of the pole at a very small cost relative to the cost to replace a pole. One industry study indicates the predicted pole life with no remedial treatment is 32.5 years compared to a predicted pole life of greater than 50 years for poles with remedial treatment.

By associating historical pole failure outage data with previously completed PITP circuits, there is an annual SAIDI and SAIFI benefit of 0.53 minutes and 0.002 interruptions per customer, respectively, through the Pole Inspection and Treatment Program.

EDO's program is "condition based," such that the level of inspection and re-treatment is dependent on each pole's actual condition. The use of a "condition based" approach provides a cost effective strategy to inspect and re-treat poles. Inspection will include above and below grade evaluations. Re-treating and load analysis will only be performed on the poles that indicate a need. The program entails a progressive level of inspection for each pole and re-treatment only when necessary. In conjunction with the pole inspection, pole loading will be assessed. Any pole found to be loaded beyond acceptable limits will be reinforced or replaced. Joint-use poles not owned by LGE and KU will only receive a loading analysis.

The estimated 2019-2023 capital costs included in the 2019BP are shown below. This proposal only requests funding for 2019.

	2019	2020	2021	2022	2023
Amount in 000s	$12,278	$12,646	$13,025	$13,416	$13,818

- **Alternatives Considered**

  1. Recommendation: NPVRR: ($000s) $16,136

  2. Alternative #1:   NPVRR: ($000s) $38,307
     Electing not to continue the PITP program would result in an increase in pole failures and outages. The NPVRR shown is the combination of the investment to replace poles as they fail rather than proactively (capital costs of $10,355k), and the resulting cost of unserved energy from these failures (costs of $27,001k). Projections indicate approximately 2,300 poles will be replaced as part of the PITP program during 2019. Without remedial actions, these 2,300 poles are projected to fail within 2 years. The cost of unserved energy was calculated using the projected number of pole failures over the next two years along with the 5-year average outage duration of preventable, pole-related failures. During a pole-failure outage, the time required to restore the outage is nearly 2.5 times longer than that of an outage taken for planned pole replacement work.

Project Description

- **Project Scope and Timeline**
  - The 2019 pole inspection and treatment program will begin in January of 2019. Inspection crews will plan to complete work in 9 months. Pole replacement crews will begin work in January and work through December of 2019. This program covers distribution poles only. Transmission poles are covered under a separate inspection program.

- **Project Cost**
  - The total estimated capital project cost for 2019 is $12,278k and $65,183k over the BP period of 2019-2023.

  - A capital contingency of 2% for the program is included to cover any variables that may deviate from the business plan projections (i.e. higher pole reject rates and miscellaneous costs such as ground-wire repairs).

Economic Analysis and Risks

- **Bid Summary**
  - The inspection and treatment work is completed by ███████████████████ ████████████████████████ The contract was approved at the November 2014 Investment Committee and will expire December 31, 2019.

  - Pole replacements will be performed by contract labor under currently approved contracts and unit prices. The wood poles used will be purchased under an existing contract for wood poles.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2019	2020	2021	Post 2021	Total
1. Capital Investment Proposed	10,949	-	-	-	10,949
2. Cost of Removal Proposed	1,329	-	-	-	1,329
3. Total Capital and Removal Proposed (1+2)	12,278	-	-	-	12,278
4. Capital Investment 2019 BP	10,949	-	-	-	10,949
5. Cost of Removal 2019 BP	1,329	-	-	-	1,329
6. Total Capital and Removal 2019 BP (4+5)	12,278	-	-	-	12,278
7. Capital Investment variance to BP (4-1)	-	-	-	-	-
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	-	-	-	-

Financial Detail by Year - O&M ($000s)	2019	2020	2021	Post 2021	Total
1. Project O&M Proposed	506	-	-	-	506
2. Project O&M 2019 BP	506	-	-	-	506
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2019 Business Plan includes this funding in projects 123136 and 123137 in the Reliability department. The projects listed on page 1 are the specific projects (in the applicable operations centers' departments) for which approval is requested. Funds will be moved from the budgeted projects to the specific operations center projects through the Corporate RAC process.

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 9,323
Materials:	$ 1,278
Local Engineering:	$ 1,098
Burdens:	$ 333
Contingency:	$ 246
Reimbursements:	($ 0)
Net Capital Expenditure:	$12,278

- **Assumptions**
  o Estimates are based on field experience from EDO inspections during the first nine years of the pole inspection and treatment program.

  o A minimal number of poles associated with structure loading will be replaced and the associated cost can be managed within existing funding.

- **Environmental**
  - There are no environmental issues. Chemicals used for the re-treatment of wood poles are EPA approved and will be applied by qualified contractors licensed for their application.

- **Risks**
  - Actual rejection rates could be greater than those experienced in previous years of the program resulting in the need for additional funding or an extended cycle to complete the program.

  - Average cost to replace a pole could increase significantly if the majority of rejects are located in metro areas.

Conclusions and Recommendation   Arbough

EDO recommends the Investment Committee approve continuation of the Distribution Wood Pole Inspection and Maintenance Program, and authorize 2019 investments of $12,278k for the project. The program continues to enhance the life of EDO wood pole assets and contribute to improved reliability performance for customers.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	
Chief Financial Officer		

Paul W. Thompson	Date	
Chairman, CEO and President		

Investment Proposal for Investment Committee Meeting on: March 29, 2017

Project Name: Richmond North Substation

Total Expenditures: $5,920k (includes $538k contingency)

Project Number(s):   Substation- 148710, Distribution- 152792, Transmission- 137752

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jim Burns/Kevin Patterson

Executive Summary
Electric Distribution Operations (EDO) - Electrical Engineering and Planning (EEP) seeks funding authority to construct a new Richmond North 12kV Substation on property acquired in late 2016. The new substation, planned along US 25 approximately one mile north of the Interstate 75 crossing at Exit 90, is required to meet existing and future service needs of customers on the north side of Richmond, KY in Madison County. Red House Substation, located approximately seven miles north of Richmond, serves 1,002 customers and is forecasted to exceed Distribution System Planning's allowable winter loading limit of 120% of the transformer's 14MVA nameplate rating during the 2018/2019 winter. This project addresses the forecasted overload at Red House Substation and also provides relief for Richmond Substation's circuit 2325 and Richmond Substation 069-5 transformer. Circuit 2325 is one of two tie circuits between Richmond and Red House Substations and serves 2,242 customers. Circuit 2325 was loaded to 90% of its conductor capacity during the winter of 2014/2015 and transformer capacity, small wire, and distance limit the ability to transfer load between Red House and Richmond Substations. Load relief for the Richmond Substation 069-5 transformer will defer a transformer upgrade project planned as a 2022/2023 project. This Investment Proposal provides for the construction of a new substation between Red House and Richmond Substations and associated circuit improvements to address transformer and circuit overloads while adding capacity and contingency to serve future load growth in the area. This project also removes two Richmond Substation transformers from the Company's "Distribution Substation Transformer Contingency Program (N1DT)" list (transformers that cannot be fully backed up for a failure of the substation transformer during high load periods during the year).

Approval is requested in the amount of $5,920k ($2,739k-2017, $3,181k-2018) to complete the construction of the new Richmond North Substation to meet existing and future service requirements and remove two distribution transformers from the N1DT Contingency Program List. Project completion is expected in December 2018. A total of $5,743k has been budgeted for this project including $4,816k ($2,200k-2017, $2,616-2018) in the 2017 EDO Business Plan (BP) and $927k ($234k-2017, $693k-2018) in the 2017 Transmission BP. The Corporate RAC has approved funding for 2017 expenditures for completion of a portion of the distribution circuit work. The remaining funding differences will be addressed in the 2018 BP.

Background

Red House 12kV (687-1) Substation consists of a 14MVA, 69-12kV transformer and three distribution circuits. It is located approximately seven miles north of Richmond, KY in northern Madison County and serves 1,002 customers, including commercial customers surrounding Exit 95 (Boonesboro Road) and Exit 97 (Clays Ferry) on Interstate 75. During the winter of 2014/2015, the Red House Substation transformer experienced actual loading of 128% of its 14MVA nameplate rating. The substation is forecasted to reach 121% under normal winter conditions during the winter of 2018/2019, exceeding Distribution System Planning's allowable winter loading limit of 120%. Richmond Substation consists of two 22.4MVA 69-12kV transformers and 5 distribution circuits.

Richmond Substation is located on the northwestern edge of the city of Richmond in Madison County and serves 3,914 customers. The Richmond 069-5 transformer reached 119% of its 22.4MVA nameplate rating during winter 2014/2015 but is not forecasted to exceed 120% of nameplate until winter 2023/2024. Circuit 2325, a circuit fed by Richmond's 069-5 transformer serves 2,242 customers and 14,000' of this circuit reached 90% of its 397kCM ACSR winter rating of 866 amps during the winter of 2014/2015. Richmond 069-5 and the Red House transformer are tied by two separate circuit routes. Due to conductor capacity and voltage concerns resulting from long circuit distances, these two tie circuits can provide only limited load transfers and contingency, and only during light loading conditions. Red House and both Richmond transformers cannot be backed up during heavier loading periods in the event of a transformer failure which places them on the N1DT Contingency Program list.

Several alternatives were evaluated to relieve existing and pending loading issues in the Richmond area, including multiple projects to independently target transformer and circuit improvements. Capacity addition at Red House was determined to not be optimal due to the small station footprint where additional space necessary for expansion is owned by an uninterested seller. Substation and circuit improvements at Richmond would have allowed load to be transferred from Red House to Richmond. This option would have addressed future overloads at Richmond Substation and on Circuit 2325 while providing transformer contingency at Richmond, but due to limits on the amount of load that could transferred it would only provide near term relief for loading issues at Red House. The least cost solution was determined to be the construction of a new substation positioned between the two substations to address loading issues at both Red House and Richmond Substations while removing two transformers at Richmond Substation from the N1DT Contingency Program list. The desired location for a new substation was determined to be in the area of US 25 north of the Interstate 75 crossing at Exit 90. This would place the substation between Richmond and Red House Substations and in close proximity to Richmond circuit 2325 and an existing KU 138kV transmission line. In late 2016/early 2017, KU purchased a suitable site along US 25 for the new circuit on Project #148251 for $230k. Once constructed, the new substation will eliminate all pending overloads and provide capacity for future growth along interstate 75 (Exits 90, 95 and 97) and US 25. This project also enhances contingency and reliability in the area and provides year round contingency for two Richmond Substation transformers.

The recommendation of this investment proposal is to construct a short transmission extension off the KU Fawkes to Clark County 138kV transmission line to serve a new delivery point, construct a new 138-12kV, 37MVA substation and upgrade 15,700' of 2/0 ACSR to 795kCM ACSR. This will

eliminate all overload conditions, relieve loading on the Richmond 069-5 transformer and provide full contingency for both Richmond Substation transformers.

A Transmission Service System Impact Study for a new service point on the Fawkes to Clark County 138kV line has been completed by TranServ. A Facilities Study has also been completed with no additional transmission improvements identified beyond the cost to serve the new station.

- **Alternatives Considered**

1. Recommended Option: NPVRR: $6,861k

   The recommended option is to construct a short transmission line extension to serve a new 138-12kV, 37MVA substation north of Richmond, including substation structures, one 2000 amp main breaker, two 1200 amp line breakers, one 138kV breaker and two 138kV MODs. Replace 15,700' of 2/0 ACSR three phase conductor with 795kCM Aluminum to provide tie circuits from the recommended Richmond North Substation to the Red House and Richmond 069-5 Substations. This provides capacity to relieve all area pending and near term loading issues, provides capacity for new growth, provides full year contingency capacity for the Richmond 069-5 and 069-6 transformers and improves contingency for Red House Substation. Both Richmond transformers are currently on the Company's N1DT Contingency Program List where a portion of customers would remain out of service for up to 24 hours in the event of a transformer failure or outage. The estimated total capital cost of this option is $5,920k.

2. Do Nothing Option: NPVRR: N/A

   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution System Planning's operating limits for distribution substation power transformers, and this practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1:   NPVRR: $17,032k

   Upgrade Red House Substation from 14MVA to 22.4MVA and reconductor 14,000' of Richmond circuit 2325 from the substation northward from 397kCM ACSR to 795kCM Aluminum in 2017/2018. This project addresses the pending overload of the Red House transformer and the pending overload on Richmond circuit 2325. However, this alternative is not recommended because it results in a less reliable and flexible system, provides less new capacity to the system and provides no contingency for the loss of either of the two transformers at Richmond substation. Failure of either of the heavily loaded Richmond substation transformers would result in an extended outage of up to 24 hours for a large number of customers until a new transformer or mobile transformer could be installed. While the loss of a substation transformer is a relatively low probability event in any given year, planning studies indicate an outage of the Richmond 069-5 transformer at peak would cause as much as 14,493kW of load to go unserved and the loss of the Richmond 069-6 transformer would cause as much as 12,415kw of load to go unserved. Using the corporate "Cost of Unserved Energy" ($17.2/kWh) with estimated load at risk going unserved at peak for 24 hours, the Cost of Unserved Energy would total $11,107k. The estimated annualized Cost of Unserved Energy based on an annual 5% probability of an outage on either transformer is $555k. The estimated capital cost of this option is $5,155k.

Project Description

- **Project Scope and Timeline**
  - Substation Project #148710: Install a 37MVA, 138-12kV transformer on property acquired in 2016 under a separate project. This estimate includes funds for labor, equipment, material, and wildlife protection for a 37MVA transformer, substation steel structure, one 15kV, 2000A main breaker, two 15kV, 1200A line breakers, one 138kV transformer breaker and two 138kV MOD's. The total estimated substation cost is $4,130k.
    - Apr-Dec 2017: Complete engineering and design. Order all material and equipment. Receive material and equipment. Begin site preparation and foundations.
    - Jan-Dec 2018: Complete foundations and install transformer, steel, breakers and all associated materials and equipment. Install control house, SCADA communications and perform final check out and commissioning.
    - Dec, 2018: Energize new substation.
  - Distribution Project #152792:   Reconductor 15,700' of 2/0 ACSR conductor with 795 Aluminum. The total estimated distribution cost is $942k.
    - Feb-Dec, 2017: Design and complete 5,200' distribution circuit construction.
    - Jan-Dec, 2018: Design and complete 10,500' distribution circuit construction.
  - Transmission Project #137752:   Install new 138kV line structures and line extension to serve the new substation. The total estimated transmission cost is $848k.
    - Jan-Dec, 2017: Complete design and order poles, conductor and materials.
    - Jan-Dec, 2018: Complete construction of 138kV tap to new substation.

- **Project Cost**
  The total estimated cost of the Richmond North 12kV Substation project is $5,920k. The transmission, substation and distribution cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% of contingency ($538k) incorporated into the project cost estimates to address any unexpected costs.

 Economic Analysis and Risks

- **Bid Summary**
  - Substation Engineering and Design will use established Engineering Procurement and Construction Management (EPCM) contracts to augment engineering and construction management resources as required.
  - Transmission and Distribution Lines will use existing material and labor contracts and follow established Supply Chain procedures. KU Company crews will be utilized based on availability at the time of work.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,739	3,165	-	-	5,904
2. Cost of Removal Proposed	-	16	-	-	16
3. Total Capital and Removal Proposed (1+2)	2,739	3,181	-	-	5,920
4. Capital Investment 2017 BP	2,434	3,309	-	-	5,743
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	2,434	3,309	-	-	5,743
7. Capital Investment variance to BP (4-1)	(305)	144	-	-	(161)
8. Cost of Removal variance to BP (5-2)	-	(16)	-	-	(16)
9. Total Capital and Removal variance to BP (6-3)	(305)	128	-	-	(177)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The Corporate RAC approved the incremental funding in 2017. The 2018 BP will reflect the net reduction in 2018.

Financial Summary ($000s):

Discount Rate: 6.5%
Capital Breakdown:
  Labor: $ 182
  Contract Labor: $2,015
  Materials: $2,408
  Local Engineering: $ 498
  Burdens: $ 250
  Contingency: $ 538
  Transportation: $ 29
  Reimbursements: ($ 0)
  Net Capital Expenditure: $5,920

- **Assumptions**
  - Substation load growth will be consistent with the company's distribution System Planning load forecast.
  - The project unknowns will not exceed the estimated contingency amounts.
  - The project will be completed in time to serve a winter 2018/2019 peak demand.

o No significant unknown costs for transmission improvements beyond the line extension to the new substation will be associated with the addition of a new service point.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**
  Failure to complete this project before winter 2018/19 could result in the overload and failure of the Red House Substation transformer and an extended outage for up to 1,002 customers and/or the overload and failure of Richmond circuit 2325 and an extended outage for up to 2,242 customers.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Richmond North Substation Project for $5,920k to eliminate a forecasted overload of the Red House Substation transformer and a future overload of the Richmond 069-5 Substation transformer and circuit. The project also provides for adequate capacity for future load additions in the Richmond and Red House areas, improves reliability and removes the Richmond 069-5 and 069-6 transformers from the N1DT Contingency Program list.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for October Investment Committee E-mail Vote

Project Name: ███████ DB Server Refresh

Total Expenditures: $2,144K ($0 contingency)

Project Number(s): IT0366B

Business Unit/Line of Business: IT Infrastructure

Prepared/Presented By: Tom Sager

Executive Summary

This project will refresh the ███████ Database (DB) servers in conjunction with the ███ Business Warehouse (BW) on ██████ upgrade. The server refresh is necessary to provide security of customer data due to the desupport of the existing BW platform. Efficiencies are gained by combining the refresh of existing ██████ DB servers with the acquisition of new ██████ DB servers for the ███ BW upgrade.

This IP is seeking approval of $2,144k of Capital (includes $0k contingency because of fixed pricing from vendor) for this upgrade effort. The project was approved by the Corp RAC in the 8+4FC. It was not included in the 2018 BP due to the assumption the AMS project would be approved, which would have covered the ██████ DB server refresh.

Background

████ BW is older technology running on out-of-date hardware (BW Accelerators) that is no longer manufactured. Obtaining spare parts will become increasingly difficult. ██████ direction with BW is ██████ (rather than current █████ DBs and ████ BW Accelerators). LKE has already migrated other ████ components to ██████ DB with server hardware purchased in 2015. This hardware is due for retirement by 2020. However, if not retired until then, the BW project will require more servers than would otherwise be needed if LKE refreshes the existing ████ ██████ DB infrastructure now. The combination of refresh and new capacity for BW is a more efficient use of resources than separate acquisitions in different years.

- **Alternatives Considered**
    1. Recommendation (12 servers: 8-6TB+4-3TB)   NPVRR: ($000s) 2,366
    2. BW now and refresh in 2020   NPVRR: ($000s) 2,651
    3. Do nothing - is not considered a viable alternative because the BW system would be unsupported by ████, risking security of customer data.

Other alternatives considered involve more servers than the recommendation made above, thus all higher cost. Analysis of workloads, resources and environments indicate the recommendation above is optimal.

- 12 Servers (12-6TB)
- 14 Servers (8-6TB+6-3TB)
- 16 servers (8-6TB+8-3TB)

Project Description

- **Project Scope and Timeline**
  This project will implement new ▮▮▮▮▮▮▮▮DB servers to house LKE's entire ▮▮▮▮▮ environment. It includes the following primary phases:
  - Finalize contract/P.O. and schedule installation services
  - Technical design
  - Install and configure

  This project will be initiated in October 2018 and will be completed by the end of 2018.

- **Project Cost**
  The total capital cost of this project is $2,144K and incremental O&M of $51K.

Economic Analysis and Risks

- **Bid Summary**
  An RFQ was placed with three manufacturers (▮▮▮▮▮▮▮▮▮▮▮▮) in October 2018. The ▮▮▮▮▮▮ quote was lowest cost. Therefore we plan to award the bid to ▮▮▮▮▮▮

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	2,144				2,144
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	2,144	-	-	-	2,144
4. Capital Investment 2018 BP	-				-
5. Cost of Removal 2018 BP					-
6. Total Capital and Removal 2018 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(2,144)	-	-	-	(2,144)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2,144)	-	-	-	(2,144)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	51				51
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	(51)	-	-	-	(51)

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$0
Contract Labor:	$0
Materials:	$2,144
Local Engineering:	$0
Burdens:	$0
Contingency:	$0
Reimbursements:	($0)
Net Capital Expenditure:	$2,144

- **Assumptions**
  Lifespan of this architecture will be 5 years.

- **Environmental**
  There is not expected to be any environmental impact as a result of this project.

- **Risks**
  No significant risks identified with this project.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the ▮▮▮▮▮▮▮ DB Server Refresh project for $2,144K to implement a new ▮▮▮▮▮▮ environment to provide security of customer data due to desupport of the existing BW platform.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent Blake	10/25/2018	1:25 PM EDT	*Paul Thompson*	10/26/2018	6:18 AM EDT
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Kent W. Blake	Date		Paul W. Thompson	Date	
Chief Financial Officer			Chairman, CEO and President		

Revised Capital Investment Proposal   **Arbough**

Revised Investment Proposal for Investment Committee Meeting on: November 28, 2018

Project Name: Solar Share Program

Total Approved Expenditures: $643k (Approved on 04/30/2018)
Total Additional Expenditures Requested: $2,232k
Total Combined Expenditure: $2,875k (Compared to $2,341k approved in December 2016)

Project Number(s): 158286, 158287, 158336, 158337

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Lisa Keels/David Huff

Reason for Revision

This project requests project sanction approval to build the first 500 kW (DC) facility and common facilities of the 4MW (DC) Photo-Voltaic (PV) solar array (Solar Share Program Phase I Contract). The full scope of the Solar Share Program was presented to the Investment Committee in December 2016 (Exhibit B attached).

The value of the initial request is included in the original Investment Proposal. See Exhibit B for the fully approved original Capital Investment Proposal.

As of July 1, 2018, 100% of the available shares have been subscribed as required to construct the first 500kW (DC) solar array (Phase I). The recently approved tariff changes eliminated the need to invoice customers for the enrollment fee. Additionally, the closing on the land purchase concluded on June 26, 2018 (as approved by the Investment Committee in April 2018). See Exhibit B for that Investment Proposal.

A competitive bid was conducted for the construction of the first array and the site common facilities. ▮▮▮▮▮▮▮▮▮▮▮ is the best evaluated bidder based on price, schedule, safety and experience. The estimated contract award value of $1,350k plus a 10% management contingency is included in the project sanction request.

Approval to offer Community Solar to our customers was granted by the Kentucky Public Service Commission in November 2016. Building the first array will confirm our commitment to the incorporation of renewable options as offerings to our customers.

Subsequent solar share arrays on this property will be initiated upon gaining additional customer subscriptions. The location of the first array on the Solar Share site will be optimized to increase

the visibility of the first array from Highway 64 to support the continued effort of attracting customers and increasing awareness required to support growth in this community solar project.

Economic Analysis and Risks

Financial Summary ($000s):	Requested
Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$115
Contract Labor and Materials:	$1,914
Contingency:	$203
Reimbursements:	($0)
Net Capital Expenditure:	$2,232
NPVRR:	$2,549

Subcontractor/Department	Cost Components	Amount ($000s)
Solar General Contractor	Panels, Inverters, Racking, Ongoing Maintenance (Includes Subsurface Rock Contingency)	$ 835
	EPC Bid Common items	$ 515
	EPC Contract Value	$ 1,350
Security	Card Readers and Annual Service Plan, 2 additional cameras on PDC (one on each door)	$ 78
Distribution Operations	Upgrade circuit from site to US-60, Air Break Switch, Regulators, 1.5 MW XFMR	$ 365
Telecom/IT	Fiber Infrastructure from Site to US-60	$ 121
Engineering/Construction Management	PE Project Management	$ 115
	Total without Contingency	$ 2,029
Contingency	Contingency	$ 203
	Total array 1 and common requested amount	$ 2,232
Real Estate & Right of Way	Land - 35 Acres Total	$ 643
	Total including Land	$ 2,875

In December 2016, the Investment Committee approved the costs associated with construction of the first array totaling $2,341k (including the purchase of the land) contingent upon full subscription. This revised proposal includes only the construction of the first 500kW solar array, extended access road, enhanced data collection, full fencing of the property, and the first phase of common structures (i.e. security).

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Arbrough
1. Capital Investment Proposed	100	2,132	-	-	2,232
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	100	2,132	-	-	2,232
4. Capital Investment 2019 BP	1,172	919	914	4,039	7,044
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	1,172	919	914	4,039	7,044
7. Capital Investment variance to BP (4-1)	1,072	(1,213)	914	4,039	4,812
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	1,072	(1,213)	914	4,039	4,812

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	105	20	56	181
2. Project O&M 2019 BP	-	105	121	465	691
3. Total Project O&M Variance to BP (2-1)	-	-	101	409	510

2019 BP amounts above for both Capital and O&M reflect not only the construction of the first phase of common structures and first solar array, but also construction and maintenance costs of the remaining seven solar arrays and the second phase of common structures.

Conclusions and Recommendation
It is recommended that the Investment Committee approve this Revised Investment Proposal for the Solar Share facility build for $2,232k to ensure customer engagement and timely execution of the array construction.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Appendix:

Exhibit A

Capital Investment ($000s)		LG&E	KU	Total
Year 1	Land	$ 283	$ 360	$ 643
Year 2	Common & Array 1	982	1,250	2,232
Year 3	Array 2	455	580	1,035
Year 4	Array 3	455	580	1,035
Year 5	Array 4	455	580	1,035
Year 6	Array 5	457	581	1,038
Year 7	Array 6	457	581	1,038
Year 8	Array 7	457	581	1,038
Year 9	Array 8	457	581	1,038
	Total Capital:	**$ 4,458**	**$ 5,674**	**$ 10,132**

*Assumed 44% LG&E / 56% KU for all assets.
*"Land" and "Common" costs are distributed over the entire 8 arrays.
E.g. The costs incurred during construction of Array 1 are larger than the costs attributed to Array 1, because a portion of those incurred costs are assigned to subsequent arrays.
* Project costs have increased since the original version due to the inclusion of stores burden on all materials.
* Costs for Arrays 2-8 are based on the originally submitted estimate as each will need to be bid separately as they are fully subscribed.

Exhibit B

Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Solar Share Program

Total Capital Expenditures Requested: $2,341k

Total Capital Expenditures Projected: $9,802k (total project including $625k contingency)

Project Number(s): To be determined once arrays are fully subscribed

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Jay Robertson/Jeff Myers/David Huff

Executive Summary

The Companies received an order from the KPSC approving the application to develop a "community" solar facility along I-64 in Simpsonville, KY (PSC Case No. 2016-00274). The subscription-based Solar Share Program will include constructing a regional facility up to 4MW (DC) for the utilities' residential and business customers interested in receiving solar energy credits generated from the facility. Solar Share facilities will be built in 500 kilowatt sections based on customer demand. Construction will begin once a 500 kilowatt section is 100% subscribed. Likewise, construction on subsequent sections will require all previous facilities plus the next facility to be at 100% subscription before each section is built.

This program is for customers who want access to solar, but prefer to avoid the space, up-front cost and maintenance requirements associated with a private system. Customers will be able to subscribe to 250-watt (DC) increments in the solar facility. The cost of participating in the program includes a non-refundable subscription fee of $40, as well as a non-levelized monthly capacity fee of $6.29 per 250-watt increment. Customers will receive a credit on their monthly bill for the solar energy generated based on the variable cost of production and their subscription level.

This program was largely borne of customer demand. Market research shows that customers in Kentucky and across the country are demanding access to solar energy. Business Development professionals have stated the importance of access to renewable energy in attracting great companies to the state. This project has the potential to expand access to renewable energy in our service territories while keeping generation assets within the company.

The total capital cost of this project is $9.8M, spent in phases triggered by customer demand. The first phase is cost-heavy due to the shared infrastructure that will need to be constructed during the project onset. $3.0M per year in capital is included in the 2017 Business Plan (BP) through 2021.

Background

The Company has performed internal market research and consulted external reports that indicate there is significant public interest in having the Companies offer a renewable energy program like the proposed Solar Share Program. This includes interest concerning state-wide economic development efforts, meeting the needs of businesses that have set corporate renewable energy-supply targets, and perhaps most importantly, regional public authorities, commercial, and residential customers continue to express great interest in alternative energy supply options. The expected benefits of completing this project are increased customer satisfaction across customer classes and an improved landscape for state-wide economic development.

This project is not required to ensure compliance with industry/environmental regulation, address potential safety issue or address an immediate operational issue. However, this project could be an asset for future federal restrictions on fossil fuel generation.

- **Alternatives Considered**
    1. Recommendation: NPVRR: $894k
    2. Alternative #1: Do nothing   NPVRR: N/A
       Do Nothing has not been considered at this time as the Company has received KPSC approval to proceed with this project, which is driven by customer demand.

Project Description

- **Project Scope and Timeline**

    This project plans to purchase a 35 acre property in Simpsonville, KY for the construction of up to 4MW (DC) of PV solar. The solar array will be built in 500kW (DC) sections based on customer demand. The proposed solar facility No. 1 will include Canadian Solar PV panels, Solectria PVI60TL inverters, and an RBI ground mount fixed-tilt racking system. Other components to the solar array include switchgear, production monitoring equipment, and a contracted maintenance plan. External to the solar generating and associated equipment, the project budget also includes allotments for distribution upgrades to the site, security measures (fencing, cameras, access card readers, trespassing detection system), landscaping, transformers, network infrastructure, and environmental permits.

    The project will be built in up to eight 500kW sections. Assuming customer subscriptions start by the end of 2016, the first section can be initiated at the beginning of 2017 and completed in Spring 2017. Subsequent sections will be initiated upon customer subscriptions. The construction timeline for sections 1 and 5 (when common facilities such as fencing and transformers will be installed) is expected to be four months each. The other 6 sections are expected to take one month each. If customer subscriptions allow for multiple sections to be built at once, the combined timeline could be compressed.

The company has experience completing a 14MW (DC)/10MW (AC) array at E.W. Brown in 2016. Key project team members who worked on the Brown Solar Facility have been consulted and their experience has been vital to the successful design of this project.

The technology installed has been proven. This project plans to incorporate silicon chrystalline-based photovoltaic panels and string inverters.

The system electrical engineering design has been completed by ████████████████ In addition, LG&E-KU engineers have completed the design of distribution upgrades and studied how this installation will affect the circuit and substation to which it is interconnected.

- **Project Cost**
  The total project capital cost is expected to be $9.8M. Cost incurred during construction of Facility No. 1 is expected to be $2M. Cost incurred during construction of Facility No. 2 is expected to be $1.1M. Cost incurred during construction of subsequent 500kW sections, other than Facility No. 5, is expected to be $834k. Cost incurred during construction of Facility No. 5 is expected to be $2.1M. Refer to the appendix for the breakdown of costs on a cash-flow basis and how they are attributed to each facility and common facilities (which are spread evenly over all sections.) The program is specifically designed so that customers participating in the program will bear the cost of the program. This project is designed to be self-funding.

  A contingency of $625k was calculated as a function of the distribution, substation, and transmission upgrades, and an amount for miscellaneous charges as determined through evaluation of similar company projects. Other than distribution, substation, and transmission upgrades, the majority of the project was bid as contracted amounts.

  The main element of this construction project will be contracted through ████████████ ████ ███ won a competitive bid process via a lump sum proposal of generic PV solar projects. The proposed cost for this specific solar facility is in line with the generic bid submitted by ███ during the RFP process. The auxiliary costs of this project are compiled from a variety of departments and a number of existing contracts.

Economic Analysis and Risks

- **Bid Summary**

MBE/WBE		
Experience		
Responsiveness		
Unit Cost ($/watt)		

The Companies accepted proposals from six companies in early 2016 – ████████████ ████████ in addition to the three finalists listed above. The proposals were written

around four generic solar projects as the contract will be used to construct our Business Solar arrays in addition to the Solar Share facilities. ▮▮▮▮▮▮▮▮▮ was chosen based on their experience in projects ranging from 250kW to 500kW, their ability to be responsive to our needs, and their lowest average cost per watt. An award recommendation (attached) was approved in May 2016 for ▮▮▮▮▮▮▮▮▮ for ▮▮▮▮ for the initial phases of this solar project. As the project progresses, if additional contract value is needed, Energy Efficieny and Supply Chain will come back to the Investment Committee for additional approval on the contract.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	580	3,534	3,915	1,773	9,802
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	580	3,534	3,915	1,773	9,802
4. Capital Investment 2017 BP	-	3,000	3,000	9,000	15,000
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	3,000	3,000	9,000	15,000
7. Capital Investment variance to BP (4-1)	(580)	(534)	(915)	7,227	5,198
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(580)	(534)	(915)	7,227	5,198

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	80	309	363	653	1,405
2. Project O&M 2017 BP	-	200	45	135	380
3. Total Project O&M variance to BP (2-1)	(80)	(109)	(318)	(518)	(1,025)

Cost incurred to date of $37k, which is a component of the $580k cost listed above. These costs have been categorized as O&M and will be transferred to capital projects once they are approved.

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Internal Labor:	$85
Contracted Labor and Materials:	$7,899
Materials:	$457
Land:	$545
Permits:	$57
Local Engineering:	$69
Burdens:	$65
Contingency:	$625
Reimbursements:	($0)
Net Capital Expenditure:	$9,802

Reimbursements do not include the expected customer revenue of $21,323k associated with this project.

- **Assumptions**

  The economic useful life of the program is 25 years.

  Customers subscribing to less than 50kW capacity will have a 12 month commitment to participate in the program. They may increase the number of shares subscribed at any time thus restarting the 12 month commitment; however, they can only make a decrease or end participation every 12 months. Customers subscribing to 50kW or more are required to sign a five year contract. No single customer may subscribe more than 50% of a Solar Share Facility (250kW), and single customers are limited to no more than 500kW total subscription across all Solar Share Facilities.

- **Environmental**

  The project team has coordinated with Environmental Affairs and applied for or received permits for the following:
  - Wetlands Delineation Determination,
  - Endangered Species Study,
  - Cumulative Environmental Assessment,
  - Historic Structures and Archaeological Study, and
  - A railroad crossing permit.

  No issues have been identified from the permitting process to date.

  There is a small wetland on the site, which the proposed construction avoids. No other environmental issues have been identified.

  There is no evidence that the site has been used for anything other than agricultural activities. There are no existing structures on the site.

  There are no air emission or forced outage issues with this project.

- **Risks**

  The major risk related to this project is low customer participation. This risk is mitigated by only building each section of the array once customer subscriptions are confirmed. However, customers subscribing to the program, then leaving after their minimum 12 month commitment could become a burden to the program financials, and ultimately, ratepayers.

  The risk of not completing the project is for customers to go elsewhere for their renewable energy needs. If the Companies do not provide it, customers may build their own arrays or leave the service territory to obtain renewable energy, in which case the Companies lose revenue.

  The Commonwealth's economic development efforts and visibility to site-selection professionals will be improved by having a renewable energy offering like the Solar Share Program available as soon as possible.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the spending request for the initial phases of the Solar Share project for $2,341k based on full subscription for Facility Array 1. Subsequent phases of the project will be presented for approval upon each achieving full subscription as well. The total full project estimate of $9,802k will be updated through the course of the construction program. This project is expected to increase the availability of renewable energy to customers in our service territory and improve customer satisfaction.

<u>Approval Confirmation for Capital Project Greater Than or Equal to $1 million:</u>

The Capital project spending in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____
Kent W. Blake
Chief Financial Officer

_____
Victor A. Staffieri
Chairman, CEO and President

Appendix

Capital Investment ($000s)		LG&E	KU	Total
Year 1	Land	$ 255	$ 325	$ 580
Year 2	Common	385	490	875
Year 2	Array 1	390	496	886
Year 2	Array 2	390	496	886
Year 2	Array 3	390	497	887
Year 3	Array 4	390	496	886
Year 3	Common	553	703	1,256
Year 3	Array 5	390	496	886
Year 3	Array 6	390	497	887
Year 4	Array 7	390	496	886
Year 4	Array 8	390	497	887
	Total Capital:	**$ 4,313**	**$ 5,489**	**$ 9,802**

*Assumed 44% LG&E / 56% KU for all assets as we do not yet know the ownership percentages of the arrays. Those will be determined once each individual array is fully subscribed.

*"Land" and "Common" costs are distributed over the entire 8 arrays. Eg. the costs incurred during construction of Array 1 are larger than the costs attributed to Array 1, because a portion of those incurred costs are assigned to subsequent arrays.

Revised Capital Investment Proposal   **Arbough**

Investment Proposal for Investment Committee Meeting on: April 25, 2018

Project Name: Solar Share Program

Total Approved Expenditures: $2,341k (Approved on 12/06/2016)

Total Revised Expenditures: $660k

Project Number(s): TBD

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Lisa Keels/David Huff

Reason for Revision

This project requests approval to purchase a 35 acre property in Simpsonville, KY for the construction of up to 4MW (DC) of PV solar. The solar array will be built in 500kW (DC) sections based on customer demand. The full scope of the Solar Share Program was approved by the Investment Committee in December 2016 (see attached for details).

The value of the revised request is included in the original Investment Proposal. See Exhibit B for the fully approved original Capital Investment Proposal.

As of April 1, 2018, nearly 45% of the first solar array has been subscribed. It is anticipated the participation level will maintain and reach the 2,000 subscriptions required to construct the first 500kW (DC) solar array in late 2018 or 2019.

Completing the purchase of the land will reduce the lead time needed to begin construction once the full subscription level is attained, addressing the concerns from early adopters. Subsequent solar share facilities on this property will be initiated upon gaining additional customer subscriptions. Additionally, all options to exercise an intent to purchase the land have been exhausted. As noted in solar share filing 2016-00274, the property currently identified was chosen due to its visibility, price, access and proximity to transmission facilities.

In the event subscription levels are not achieved, the land will be sold at market value.

Financial Summary

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.49%	6.58%	Current rate
Capital Breakdown:			
Labor:	$85	$0	
Contract Labor and materials:	$7,899	$0	
Materials:	$457	$0	
Land	$545	$610	Includes additional purchase options and easements
Permits	$57	$50	
Local Engineering:	$69	$0	
Contingency:	$625	$0	
Reimbursements:	($0)	($0)	
Net Capital Expenditure:	$9,802	$660	
NPVRR:	$894	$986	

The approved amount above includes costs for the full solar project. In December 2016, the Investment Committee approved the costs associated with construction of the first array totaling $2,341k, which includes the purchase of the land, contingent upon full subscription. The approved project capital amount does not include the expected customer revenue of $21,323k as a reimbursement associated with the full solar project. However, the CEM NPVRR calculation does include the customer revenue. This revised proposal includes only the purchase of the land and the NPVRR calculation for this revision does not include customer revenue.

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	660	-	-	-	660
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	660	-	-	-	660
4. Capital Investment 2018 BP	1,839	919	914	3,125	6,797
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,839	919	914	3,125	6,797
7. Capital Investment variance to BP (4-1)	1,179	919	914	3,125	6,137
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	1,179	919	914	3,125	6,137

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	6	12	12	23	53
2. Project O&M 2018 BP	117	133	149	352	750
3. Total Project O&M Variance to BP (2-1)	111	121	137	328	697

Cost incurred to date of $99k ($60k in 2016 and $39k in 2017), which is a component of the $660k cost listed above, has been charged to O&M and will be reclassified to the capital project once it is approved. 2018 BP amounts above for both Capital and O&M reflect not only the purchase of

the land, but also construction and maintenance costs of solar arrays and common structures (although fencing and security).

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the Solar Share land purchase for $660k to ensure customer engagement and timely execution of the array construction.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

Exhibit A

Capital Investment ($000s)		LG&E	KU	Total
Year 1	Land	$ 290	$ 370	$ 660
Year 1	Common	350	445	795
Year 1	Array 1	404	515	919
Year 2	Array 2	404	515	919
Year 3	Array 3	402	512	914
Year 4	Array 4	402	512	914
Year 5	Common	571	726	1,297
Year 5	Array 5	402	512	914
Year 6	Array 6	402	512	914
Year 7	Array 7	402	512	914
Year 8	Array 8	402	512	914
	Total Capital:	**$ 4,431**	**$ 5,643**	**$ 10,074**

*Assumed 44% LG&E / 56% KU for all assets as we do not yet know the ownership percentages of the arrays. Those will be determined once each individual array is fully subscribed.
*"Land" and "Common" costs are distributed over the entire 8 arrays. E.g. The costs incurred during construction of Array 1 are larger than the costs attributed to Array 1, because a portion of those incurred costs are assigned to subsequent arrays.
* Project costs have increased since the previous version due to the inclusion of stores burden on all materials.

Revised Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: April 25, 2018

Project Name: Solar Share Program

Total Approved Expenditures: $2,341k (Approved on 12/06/2016)

Total Revised Expenditures: $660k

Project Number(s): TBD

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Lisa Keels/David Huff

Reason for Revision

This project requests approval to purchase a 35 acre property in Simpsonville, KY for the construction of up to 4MW (DC) of PV solar. The solar array will be built in 500kW (DC) sections based on customer demand. The full scope of the Solar Share Program was approved by the Investment Committee in December 2016 (see attached for details).

The value of the revised request is included in the original Investment Proposal. See Exhibit B for the fully approved original Capital Investment Proposal.

As of April 1, 2018, nearly 45% of the first solar array has been subscribed. It is anticipated the participation level will maintain and reach the 2,000 subscriptions required to construct the first 500kW (DC) solar array in late 2018 or 2019.

Completing the purchase of the land will reduce the lead time needed to begin construction once the full subscription level is attained, addressing the concerns from early adopters. Subsequent solar share facilities on this property will be initiated upon gaining additional customer subscriptions. Additionally, all options to exercise an intent to purchase the land have been exhausted. As noted in solar share filing 2016-00274, the property currently identified was chosen due to its visibility, price, access and proximity to transmission facilities.

In the event subscription levels are not achieved, the land will be sold at market value.

Financial Summary **Arbough**

Financial Summary ($000s):	Approved	Revised	Explanation
Discount Rate:	6.49%	6.58%	Current rate
Capital Breakdown:			
Labor:	$85	$0	
Contract Labor and materials:	$7,899	$0	
Materials:	$457	$0	
Land	$545	$610	Includes additional purchase options and easements
Permits	$57	$50	
Local Engineering:	$69	$0	
Contingency:	$625	$0	
Reimbursements:	($0)	($0)	
Net Capital Expenditure:	$9,802	$660	
NPVRR:	$894	$986	

The approved amount above includes costs for the full solar project. In December 2016, the Investment Committee approved the costs associated with construction of the first array totaling $2,341k, which includes the purchase of the land, contingent upon full subscription. The approved project capital amount does not include the expected customer revenue of $21,323k as a reimbursement associated with the full solar project. However, the CEM NPVRR calculation does include the customer revenue. This revised proposal includes only the purchase of the land and the NPVRR calculation for this revision does not include customer revenue.

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	660	-	-	-	660
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	660	-	-	-	660
4. Capital Investment 2018 BP	1,839	919	914	3,125	6,797
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	1,839	919	914	3,125	6,797
7. Capital Investment variance to BP (4-1)	1,179	919	914	3,125	6,137
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	1,179	919	914	3,125	6,137

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	6	12	12	23	53
2. Project O&M 2018 BP	117	133	149	352	750
3. Total Project O&M Variance to BP (2-1)	111	121	137	328	697

Cost incurred to date of $99k ($60k in 2016 and $39k in 2017), which is a component of the $660k cost listed above, has been charged to O&M and will be reclassified to the capital project once it is approved. 2018 BP amounts above for both Capital and O&M reflect not only the purchase of

the land, but also construction and maintenance costs of solar arrays and common structures (such as fencing and security).

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the Solar Share land purchase for $660k to ensure customer engagement and timely execution of the array construction.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

Exhibit A

Capital Investment ($000s)		LG&E	KU	Total
Year 1	Land	$ 290	$ 370	$ 660
Year 1	Common	350	445	795
Year 1	Array 1	404	515	919
Year 2	Array 2	404	515	919
Year 3	Array 3	402	512	914
Year 4	Array 4	402	512	914
Year 5	Common	571	726	1,297
Year 5	Array 5	402	512	914
Year 6	Array 6	402	512	914
Year 7	Array 7	402	512	914
Year 8	Array 8	402	512	914
Total Capital:		**$ 4,431**	**$ 5,643**	**$ 10,074**

*Assumed 44% LG&E / 56% KU for all assets as we do not yet know the ownership percentages of the arrays. Those will be determined once each individual array is fully subscribed.
*"Land" and "Common" costs are distributed over the entire 8 arrays. E.g. The costs incurred during construction of Array 1 are larger than the costs attributed to Array 1, because a portion of those incurred costs are assigned to subsequent arrays.
* Project costs have increased since the previous version due to the inclusion of stores burden on all materials.

Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Solar Share Program

Total Capital Expenditures Requested: $2,341k

Total Capital Expenditures Projected: $9,802k (total project including $625k contingency)

Project Number(s): To be determined once arrays are fully subscribed

Business Unit/Line of Business: Customer Services

Prepared/Presented By: Jay Robertson/Jeff Myers/David Huff

Executive Summary

The Companies received an order from the KPSC approving the application to develop a "community" solar facility along I-64 in Simpsonville, KY (PSC Case No. 2016-00274). The subscription-based Solar Share Program will include constructing a regional facility up to 4MW (DC) for the utilities' residential and business customers interested in receiving solar energy credits generated from the facility. Solar Share facilities will be built in 500 kilowatt sections based on customer demand. Construction will begin once a 500 kilowatt section is 100% subscribed. Likewise, construction on subsequent sections will require all previous facilities plus the next facility to be at 100% subscription before each section is built.

This program is for customers who want access to solar, but prefer to avoid the space, up-front cost and maintenance requirements associated with a private system. Customers will be able to subscribe to 250-watt (DC) increments in the solar facility. The cost of participating in the program includes a non-refundable subscription fee of $40, as well as a non-levelized monthly capacity fee of $6.29 per 250-watt increment. Customers will receive a credit on their monthly bill for the solar energy generated based on the variable cost of production and their subscription level.

This program was largely borne of customer demand. Market research shows that customers in Kentucky and across the country are demanding access to solar energy. Business Development professionals have stated the importance of access to renewable energy in attracting great companies to the state. This project has the potential to expand access to renewable energy in our service territories while keeping generation assets within the company.

The total capital cost of this project is $9.8M, spent in phases triggered by customer demand. The first phase is cost-heavy due to the shared infrastructure that will need to be constructed during the project onset. $3.0M per year in capital is included in the 2017 Business Plan (BP) through 2021.

- 1 -

Background

The Company has performed internal market research and consulted external reports that indicate there is significant public interest in having the Companies offer a renewable energy program like the proposed Solar Share Program. This includes interest concerning state-wide economic development efforts, meeting the needs of businesses that have set corporate renewable energy-supply targets, and perhaps most importantly, regional public authorities, commercial, and residential customers continue to express great interest in alternative energy supply options. The expected benefits of completing this project are increased customer satisfaction across customer classes and an improved landscape for state-wide economic development.

This project is not required to ensure compliance with industry/environmental regulation, address potential safety issue or address an immediate operational issue. However, this project could be an asset for future federal restrictions on fossil fuel generation.

- **Alternatives Considered**
  1. Recommendation: NPVRR: $894k
  2. Alternative #1: Do nothing   NPVRR: N/A
     Do Nothing has not been considered at this time as the Company has received KPSC approval to proceed with this project, which is driven by customer demand.

Project Description

- **Project Scope and Timeline**

  This project plans to purchase a 35 acre property in Simpsonville, KY for the construction of up to 4MW (DC) of PV solar. The solar array will be built in 500kW (DC) sections based on customer demand. The proposed solar facility No. 1 will include Canadian Solar PV panels, Solectria PVI60TL inverters, and an RBI ground mount fixed-tilt racking system. Other components to the solar array include switchgear, production monitoring equipment, and a contracted maintenance plan. External to the solar generating and associated equipment, the project budget also includes allotments for distribution upgrades to the site, security measures (fencing, cameras, access card readers, trespassing detection system), landscaping, transformers, network infrastructure, and environmental permits.

  The project will be built in up to eight 500kW sections. Assuming customer subscriptions start by the end of 2016, the first section can be initiated at the beginning of 2017 and completed in Spring 2017. Subsequent sections will be initiated upon customer subscriptions. The construction timeline for sections 1 and 5 (when common facilities such as fencing and transformers will be installed) is expected to be four months each. The other 6 sections are expected to take one month each. If customer subscriptions allow for multiple sections to be built at once, the combined timeline could be compressed.

The company has experience completing a 14MW (DC)/10MW (AC) array at E.W. Brown in 2016. Key project team members who worked on the Brown Solar Facility have been consulted and their experience has been vital to the successful design of this project.

The technology installed has been proven. This project plans to incorporate silicon chrystalline-based photovoltaic panels and string inverters.

The system electrical engineering design has been completed by ███████████████ In addition, LG&E-KU engineers have completed the design of distribution upgrades and studied how this installation will affect the circuit and substation to which it is interconnected.

- **Project Cost**
  The total project capital cost is expected to be $9.8M. Cost incurred during construction of Facility No. 1 is expected to be $2M. Cost incurred during construction of Facility No. 2 is expected to be $1.1M. Cost incurred during construction of subsequent 500kW sections, other than Facility No. 5, is expected to be $834k. Cost incurred during construction of Facility No. 5 is expected to be $2.1M. Refer to the appendix for the breakdown of costs on a cash-flow basis and how they are attributed to each facility and common facilities (which are spread evenly over all sections.) The program is specifically designed so that customers participating in the program will bear the cost of the program. This project is designed to be self-funding.

  A contingency of $625k was calculated as a function of the distribution, substation, and transmission upgrades, and an amount for miscellaneous charges as determined through evaluation of similar company projects. Other than distribution, substation, and transmission upgrades, the majority of the project was bid as contracted amounts.

  The main element of this construction project will be contracted through ████████████████ ████████ won a competitive bid process via a lump sum proposal of generic PV solar projects. The proposed cost for this specific solar facility is in line with the generic bid submitted by ████ during the RFP process. The auxiliary costs of this project are compiled from a variety of departments and a number of existing contracts.

Economic Analysis and Risks

- **Bid Summary**

MBE/WBE			
Experience			
Responsiveness			
Unit Cost ($/watt)			

The Companies accepted proposals from six companies in early 2016 – ████████████████ ████████████ in addition to the three finalists listed above. The proposals were written

around four generic solar projects as the contract will be used to construct our Business ██████
arrays in addition to the Solar Share facilities. ████████████████ was chosen based on
their experience in projects ranging from 250kW to 500kW, their ability to be responsive to
our needs, and their lowest average cost per watt. An award recommendation (attached) was
approved in May 2016 for ████████████████ for ███████ for the initial phases of this
solar project. As the project progresses, if additional contract value is needed, Energy
Efficieny and Supply Chain will come back to the Investment Committee for additional
approval on the contract.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	580	3,534	3,915	1,773	9,802
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	580	3,534	3,915	1,773	9,802
4. Capital Investment 2017 BP	-	3,000	3,000	9,000	15,000
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	3,000	3,000	9,000	15,000
7. Capital Investment variance to BP (4-1)	(580)	(534)	(915)	7,227	5,198
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(580)	(534)	(915)	7,227	5,198

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	80	309	363	653	1,405
2. Project O&M 2017 BP	-	200	45	135	380
3. Total Project O&M variance to BP (2-1)	(80)	(109)	(318)	(518)	(1,025)

Cost incurred to date of $37k, which is a component of the $580k cost listed above. These costs
have been categorized as O&M and will be transferred to capital projects once they are approved.

Financial Summary ($000s):
Discount Rate: 6.49%
Capital Breakdown:
   Internal Labor: $85
   Contracted Labor and Materials: $7,899
   Materials: $457
   Land: $545
   Permits: $57
   Local Engineering: $69
   Burdens: $65
   Contingency: $625
   Reimbursements: ($0)
   Net Capital Expenditure: $9,802

Reimbursements do not include the expected customer revenue of $21,323k associated with this
project.

- **Assumptions**

  The economic useful life of the program is 25 years.

  Customers subscribing to less than 50kW capacity will have a 12 month commitment to participate in the program. They may increase the number of shares subscribed at any time thus restarting the 12 month commitment; however, they can only make a decrease or end participation every 12 months. Customers subscribing to 50kW or more are required to sign a five year contract. No single customer may subscribe more than 50% of a Solar Share Facility (250kW), and single customers are limited to no more than 500kW total subscription across all Solar Share Facilities.

- **Environmental**

  The project team has coordinated with Environmental Affairs and applied for or received permits for the following:
    o Wetlands Delineation Determination,
    o Endangered Species Study,
    o Cumulative Environmental Assessment,
    o Historic Structures and Archaeological Study, and
    o A railroad crossing permit.
  No issues have been identified from the permitting process to date.

  There is a small wetland on the site, which the proposed construction avoids. No other environmental issues have been identified.

  There is no evidence that the site has been used for anything other than agricultural activities. There are no existing structures on the site.

  There are no air emission or forced outage issues with this project.

- **Risks**

  The major risk related to this project is low customer participation. This risk is mitigated by only building each section of the array once customer subscriptions are confirmed. However, customers subscribing to the program, then leaving after their minimum 12 month commitment could become a burden to the program financials, and ultimately, ratepayers.

  The risk of not completing the project is for customers to go elsewhere for their renewable energy needs. If the Companies do not provide it, customers may build their own arrays or leave the service territory to obtain renewable energy, in which case the Companies lose revenue.

  The Commonwealth's economic development efforts and visibility to site-selection professionals will be improved by having a renewable energy offering like the Solar Share Program available as soon as possible.

Conclusions and Recommendation Arbough

It is recommended that the Investment Committee approve the spending request for the initial phases of the Solar Share project for $2,341k based on full subscription for Facility Array 1. Subsequent phases of the project will be presented for approval upon each achieving full subscription as well. The total full project estimate of $9,802k will be updated through the course of the construction program. This project is expected to increase the availability of renewable energy to customers in our service territory and improve customer satisfaction.

Approval Confirmation for Capital Project Greater Than or Equal to $1 million:

The Capital project spending in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Appendix

Capital Investment ($000s)

		LG&E		KU		Total
Year 1	Land	$ 255	$	325	$	580
Year 2	Common	385		490		875
Year 2	Array 1	390		496		886
Year 2	Array 2	390		496		886
Year 2	Array 3	390		497		887
Year 3	Array 4	390		496		886
Year 3	Common	553		703		1,256
Year 3	Array 5	390		496		886
Year 3	Array 6	390		497		887
Year 4	Array 7	390		496		886
Year 4	Array 8	390		497		887
	Total Capital:	**$ 4,313**	**$**	**5,489**	**$**	**9,802**

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Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Solar Share Program

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Prepared/Presented By: Jay Robertson/Jeff Myers/David Huff

Executive Summary

The Companies received an order from the KPSC approving the application to develop a "community" solar facility along I-64 in Simpsonville, KY (PSC Case No. 2016-00274). The subscription-based Solar Share Program will include constructing a regional facility up to 4MW (DC) for the utilities' residential and business customers interested in receiving solar energy credits generated from the facility. Solar Share facilities will be built in 500 kilowatt sections based on customer demand. Construction will begin once a 500 kilowatt section is 100% subscribed. Likewise, construction on subsequent sections will require all previous facilities plus the next facility to be at 100% subscription before each section is built.

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The total capital cost of this project is $9.8M, spent in phases triggered by customer demand. The first phase is cost-heavy due to the shared infrastructure that will need to be constructed during the project onset. $3.0M per year in capital is included in the 2017 Business Plan (BP) through 2021.

Background

The Company has performed internal market research and consulted external reports that indicate there is significant public interest in having the Companies offer a renewable energy program like the proposed Solar Share Program. This includes interest concerning state-wide economic development efforts, meeting the needs of businesses that have set corporate renewable energy-supply targets, and perhaps most importantly, regional public authorities, commercial, and residential customers continue to express great interest in alternative energy supply options. The expected benefits of completing this project are increased customer satisfaction across customer classes and an improved landscape for state-wide economic development.

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  1. Recommendation: NPVRR: $894k
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Project Description

- **Project Scope and Timeline**

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Economic Analysis and Risks

- **Bid Summary**

MBE/WBE	
Experience	
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Unit Cost ($/watt)	

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Reimbursements:	($0)
Net Capital Expenditure:	$9,802

Reimbursements do not include the expected customer revenue of $21,323k associated with this project.

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Conclusions and Recommendation   **Arbough**

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Kent W. Blake	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Appendix

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Year 3	Common	553		703		1,256
Year 3	Array 5	390		496		886
Year 3	Array 6	390		497		887
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Year 4	Array 8	390		497		887
	Total Capital:	**$ 4,313**	**$**	**5,489**	**$**	**9,802**

*Assumed 44% LG&E / 56% KU for all assets as we do not yet know the ownership percentages of the arrays. Those will be determined once each individual array is fully subscribed.

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Investment Proposal for Investment Committee Meeting on: March 29, 2017

Project Name: TC2 Generator Excitation Replacement

Total Expenditures: $2,160k gross, ($1,620k net) (Including $196k gross, $147k net of contingency)

Project Number(s): 153053LGE/153053KU

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Emmett Moore/Tyson Janisch

Executive Summary

The Trimble County Unit 2 (TC2) generator excitation system is a Hitachi Type VCS6000. This Hitachi exciter, one of three in-service in the United States, was commissioned into service in 2011 as part of the TC2 Hitachi turbine-generator. The plant faces many challenges in maintaining the Hitachi exciter including limited support and extended lead-time for replacement parts. Since many questions require involvement from Hitachi Japan, responses are delayed causing extended down time when a problem or question arises.

The scope of this project is complete replacement of the TC2 generator excitation system to increase reliability by ensuring support and parts are readily available. All hardware components of the current exciter will be replaced, with the exception of the existing bus and cabling. Along with the hardware, a new software platform will provide seamless integration with the TC2 control system.

The total project cost is $2,160k gross ($1,620k net). The 2017BP included $1,171k (net) with $585k budgeted in 2017 and $586k budgeted in 2018. The overage in 2017 will be funded from reallocation of funds from other projects and has been approved in the RAC 1+11 forecast.

Background Arbough

The project mitigates the risk associated with limited resources and parts availability when TC2 experiences forced outage time due to exciter issues. Hitachi's Original Equipment Manufacturer (OEM) representative in the United States is ████, and it has only one qualified person to work on or troubleshoot issues specific to the current TC2 Hitachi exciter. Based on the plant's experience, the lead-time for many integral components is six to twelve months.

When Trimble County attempted to source individual components during the research of this project, it was discovered that certain suppliers, although located in the United States, would not allow direct orders or discuss other alternatives that might reduce the component lead-time. Because of this obstruction, there is not a viable way to source these parts from the original supplier or an alternate supplier directly. Additionally, the lack of cooperation from these component manufacturers makes reverse engineering these parts particularly difficult.

The exciter software provided by Hitachi is written in Japanese. This requires the Japanese version to be compiled, translated to English, and then downloaded to the exciter. Due to an error in this process, a software update caused a delayed startup of TC2 in 2012. The result of this software error caused the exciter to operate backwards. The proposed exciter replacement (from Hitachi to ████████████ will simplify the process of software updates and logic changes and result in fewer repair decisions that require significant time to resolve.

- **Alternatives Considered**
  1. Recommendation: ████ Full Replacement   NPVRR: ($000s) $1,890

  2. Alternative #1: ████ Front-End Upgrade   NPVRR: ($000s) $2,280
     The front-end upgrade replaces the controls portion of the current exciter and leaves a majority of the existing hardware components in use. This alternative addresses the software issues associated with translating Japanese code to English prior to updating the exciter system. In addition, this alternative addresses the delayed response to support calls that currently are routed through Japan. While this is a lower capital cost alternative, the substantial lead-time of parts excluded in the upgrade would still leave the plant in a vulnerable position of significant risk.

  3. Alternative #2: Do Nothing   NPVRR: ($000s) $2,929
     Do not replace any portion of the existing TC2 exciter. Based on a lead-time of 26 to 52 weeks on replacement parts, along with the availability of qualified repair technicians, major downtime is expected in the event of a component failure. Note that this does not factor other equipment repair costs or downtime that could occur in the event of an excitation failure.

Project Description   Arbough

- **Project Scope and Timeline**

The scope of the project is a complete replacement of the TC2 exciter. The project will span 2017 and 2018. The engineering, design, and factory acceptance testing will take place during 2017. The plant will receive the hardware in 2017, and the installation will take place during the TC2 Spring 2018 outage. Comprehensive testing will take place at the vendor factory. The demolition of the Hitachi excitation cabinets and hardware begins at the onset of the outage. The existing cabling and bus will be de-terminated and reused wherever feasible. When demolition is complete, installation of new hardware will commence. LG&E will conduct offline testing, online commissioning and performance testing with contractor assistance.

The project timeline with major milestones is as follows:

March 2017 –   Project Approval
April 2017 –   Award Contract/Kickoff Meeting
June 2017 –   Engineering complete and approved
October 2017 –   Factory Acceptance Testing
December 2017 – Receive new hardware onsite and approve commissioning procedures
March 2018 –   Demolition/construction of new hardware
April 2018 –   Offline testing
April/May 2018 – Commissioning and performance online testing

- **Project Cost**

The total cost of the project is expected to be $2,160k ($1,620k net), including sales tax, freight and burdens. There is $196k ($147k net) (10%) allotted for contingency included in the total. Further, the total includes $75k estimated for the owner's engineer, and another $75k estimated for company labor.

Economic Analysis and Risks

- **Bid Summary**

Monetization	
Base Bid	
AC Breaker	
Extended I/O	
Spare Parts	
Total Cost ($000s)	
Standardization Adder	
Total Cost of Ownership	

▮▮▮▮▮▮▮ were invited to bid on the project. ▮▮▮ provided two options in the bid, full replacement of the exciter or a front-end upgrade of the exciter controls. ▮ provided a bid

for full replacement of the exciter. Please note that ▉ was invited to bid on the exciter because **Although**
of its TC2 Turbine Control System (TCS) upgrade bid. At the time, the plant sought increased integration between the exciter software and the TCS. The plant has since recommended the TCS upgrade be awarded to ▉▉▉▉▉▉▉, which mitigates this concern due to the expansive ▉▉▉▉ experience that plant personnel possess.

Although the ▉▉ bid is less expensive based on first cost, the plant recommendation is for a ▉▉▉▉ full replacement of the TC2 exciter. The ▉▉▉▉ recommendation builds consistency within the fleet with multiple exciter units already in-service including TC1. The familiarity of both plant personnel and Generation Engineering is deemed highly advantageous to the recommendation as maintenance and operation are directly coupled to unit performance. The ▉▉▉▉ software readily interfaces with the existing generator protection system and plant DCS control and monitoring system. Further, the ▉▉▉▉ system will cleanly integrate with the main turbine controls being upgraded during the 2018 spring outage. The lack of these benefits within the ▉▉ offering is monetized in the bid summary table on the Standardization Adder line. When considering this adder, the total cost of ownership comparison favors the selection of ▉▉▉.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	972	648			1,620
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	972	648	-	-	1,620
4. Capital Investment 2017 BP	585	586			1,171
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	585	586	-	-	1,171
7. Capital Investment variance to BP (4-1)	(387)	(62)	-	-	(449)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(387)	(62)	-	-	(449)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:

Labor:	$75
Contract Labor:	$310
Materials:	$1,401
Local Engineering:	$84
Burdens:	$94
Contingency:	$196
Reimbursements:	($540)
Net Capital Expenditure:	$1,620

- **Assumptions**

  - Inflation is not considered since all pricing is based on 2018 prices.

  - Alternative #1 ▇▇▇ Front-End Upgrade – Availability disimprovement of 3.5 weeks each year with a probability percentage of 0.6% starting in 2017 and increasing by 0.2% every year until 2056.

  - Do Nothing – Availability disimprovement of 8 weeks each year with a probability percentage of 0.6% starting in 2017 and increasing by 0.2% each year until 2056.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes, like-kind
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	No

#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	**Arbough** No

- **Risks**

  - The TC2 exciter is an integral component of the generator system. There is always a risk that a mistake during installation results in component damage. That risk is mitigated by hiring a seasoned owner's engineer, thorough factory acceptance testing and extensive testing during commissioning of the new installation.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC2 Generator Excitation Replacement project for $1,620k (net) / $2,160k (gross) to improve reliability through improved support and critical part availability.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Investment Proposal for Investment Committee Meeting on: <u>December 19, 2016</u>

Project Name: <u>TC 2 Turbine Controls Upgrade</u>

Total Expenditures: <u>$1,416k gross, ($1,063k net)   (Including contingency of 10% or $97k net)</u>

Project Number(s): <u>140048LGE</u>

Business Unit/Line of Business: <u>Power Generation</u>

Prepared/Presented By: <u>Tommy Della Rocco</u>

Executive Summary

Trimble County Unit 2 (TC 2) steam turbine, generator, and balance of plant related to the steam turbine generator is controlled by a ▮▮▮▮▮▮▮ control system. The ▮▮▮▮▮ reaches end-of-life in 2019 and, therefore, parts and support are not guaranteed. The ▮▮▮▮▮ control system engineering and operating interface also uses a ▮▮▮▮▮▮▮▮▮▮▮ that will no longer be supported by ▮▮▮▮▮ after January 2020, which violates a NERC Alert from February 2016.

The scope of this project is to upgrade the TC 2 Turbine Control System (TCS) to ensure parts and support are available and the system is in compliance. The entire hardware platform will be upgraded to modern components, and while maintaining all existing features, the software will be rewritten and enhanced by the vendor providing the hardware.

TC 2 TCS is unique in the fact that the hardware and software are from two different companies. The hardware is all ▮▮▮▮▮▮▮▮▮ and the software is designed by ▮▮▮▮ The issue is further complicated by the fact that neither company is keen on providing support for the system as a whole. This project will consolidate the supplier for both hardware and software and ensure support for the entire TCS.

The total cost of this project is $1,416k gross ($1,063k net). The 2017BP included $980k (net) with $390k in 2017 and $590k in 2018. The overage in 2017 will be funded from reallocation of funds from other Capital projects within the plant budget as part of the 2017BP.

Background   **Arbough**

The project addresses an industry regulation where ██████ will no longer be supported by ██████ in January 2020. NERC Alert dated February 9, 2016 implies that all control systems' operating systems should be supported by the OEM to ensure security updates are available to prevent unauthorized use.

LG&E recently performed a Human Machine Interface (HMI) upgrade on TC 2 when ██████ ceased support of ████████; however, TC 2 has been in service for less than seven years and, as such, it has not required an entire TCS upgrade. There have been card failures on the ████ ██████ but replacement parts have always been in stock and available for re-order. However, in 2019, technical support and replacement parts will no longer be available; therefore, we are recommending this upgrade occur in 2018. This project will address this issue and guarantee parts are in stock and available for re-order.

██ manufactured the TC2 TCS hardware, whereas the logic was written by ██████; consequently, neither ██ nor ██████ will accept full ownership of the TC2 TCS. Even though ████ is the TC2 TCS OEM, they do not currently provide timely and satisfactory support, and ██ and other outside vendors are hesitant to offer TC2 technical support as it is not their logic or operating philosophy. The proposed controls upgrade will address this issue. The winning bidder will agree to provide ongoing operational support for at least 10 years.

- **Alternatives Considered**

  1. Recommendation: Complete TCS Upgrade   NPVRR: ($000s) $1,228
  2. Alternative #1: Stock obsolete parts/Upgrade HMI NPVRR: ($000s) $11,599
  3. Alternative #2: Do nothing   NPVRR: ($000s) $11,566

Alternative #1 is to upgrade the HMI to ████████ and stock soon to be obsolete parts. Upgrading the HMIs to ████████ prior to 2020 will cost approximately $115k which would ensure compliance with the current NERC Alert. Obsolete parts can be purchased in surplus for around $50k and would provide a short term fix to any part failures. It is inevitable that more parts will become obsolete and interfacing systems will have compatibility issues with legacy components thus leading to a failure that will force an entire TCS upgrade or replacement which could lead to extensive outages.

It is recommended that the entire TCS be upgraded in 2018. This recommendation will result in more funding upfront, but it will save significant downtime and resulting cost in the future.

Project Description

- **Project Scope and Timeline**

  The project will span 2017 and 2018. The engineering, design, and factory acceptance testing will take place during 2017, and the installation will take place during the TC2 spring 2018 outage. The engineering phase is quite extensive. The required logic that controls the turbine,

generator, and balance of plant will all be copied with specific enhancements requested by Trimble County as well as from the vendor. Comprehensive testing will take place at the vendor factory. When the outage begins, then the demolition of any applicable hardware will start and installation of new hardware will follow. LGE will conduct a series of offline testing and online commissioning and performance testing.

The TC 2 Turbine Driven Boiler Feed Pumps were recently converted from OEM ▬▬ controls to ▬▬▬▬▬▬ controls during the TC2 Spring 2015 outage. If ▬▬▬▬ is the successful bidder, TC2's new main turbine controls will be identical to the TC2 TDBFP ▬▬▬▬▬ controls.

Both the ▬▬▬▬ and ▬▬▬▬▬▬ are used throughout the fleet for TCS and are proven reliable.

A TCS technical specification was created and used for the bidders.

The project timeline with major milestones are as follows:

February 2017 – Award Contract
March 2017 – Kickoff meeting
October 2017 – Engineering complete and approved
November 2017 – Factory Acceptance Testing
February 2018 – Receive new hardware onsite and approve commissioning procedures
March 2018 – Demolition/construction of new hardware
April 2018 – Offline testing
April/May 2018 – Commissioning and performance online testing

- **Project Cost**

The total cost of the project is expected to be $1,287k ($965k net), including sales tax and burdens. There is $129k (or 10%) allotted for contingency to bring the total to $1,416k ($1,063k net). Firm bids have been received for the TCS and construction management; however, the demolition, construction, and owner's engineer have not been bid out. We have estimated the construction and demolition costs based on a very similar project performed in 2015 and extrapolated out the costs based on the number of I/O points for the TCS. Time and Material pricing has been received for the owner's engineer and the amount of time has been predicted based on the scope and previous projects.

The upgraded TCS will interface with over 700 field instruments and is expected that there may be some changes required that are not foreseen.

Economic Analysis and Risks

- **Bid Summary (See Appendix A for details)**

MBE/WBE		
Total Cost ($000s)		
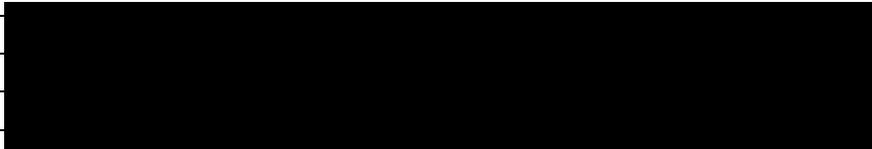
███████ and ██ were invited to bid on the project. The bids were received on October 23, 2016. ██ has proposed upgrading the ████████ to ████████. ████████ has proposed replacing the ████████ with ████████████ which controls the remaining systems on TC 2 and the entire control system on TC 1. ████ controls upgrade is less extensive and, therefore, should present less risk and cost; whereas ████████ proposal would require significantly lower O&M costs going forward, since all steam turbines would be controlled by one Distributed Control System (DCS). The bid summary indicates a relatively flat cost between the ██ and ██████ options, but for the following reasons ███████ is recommended:

- Future upgrade costs for ███████ is $25k and GE is approximately $500k ████ base price plus HMI upgrades)
- ████████ field services and support contract currently exists at no extra cost for new TCS. An equivalent contract would have to be created between ██ and LGE for extra costs.
- Plant personnel are familiar with ███████████ controls and as a result issues are resolved quickly and efficiently. Significant training would be required to bring plant personnel to the same experience level and efficiency.

The CEM recommended values are based on an award to ████████

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	-	490	573	-	1,063
2. Cost of Removal Proposed	-				-
3. Total Capital and Removal Proposed (1+2)	-	490	573	-	1,063
4. Capital Investment 2017 BP		390	590	-	980
5. Cost of Removal 2017 BP					-
6. Total Capital and Removal 2017 BP (4+5)	-	390	590	-	980
7. Capital Investment variance to BP (4-1)	-	(100)	17	-	(83)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(100)	17	-	(83)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed		-	-	-	-
2. Project O&M 2017 BP		-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:
Labor:	$ 50
Contract Labor:	$ 761
Materials:	$ 335
Local Engineering:	$ 25
Burdens and Tax:	$ 117
Contingency:	$ 129
Reimbursements	($ 354)
Net Capital Expenditure:	$1,063

- **Assumptions**

  - Inflation is not considered since all pricing is based on 2018 prices.
  - The product lifecycle of the █████ control system are typically 10 – 12 years.
  - Spare obsolete parts will ensure the unit runs without issue for five years.
  - █ will install new versions of software when they upgrade the HMIs to ████. That new software may not communicate with the obsolete cards and would cause a one week outage to correct.
  - The ███ system as a whole will be obsolete by 2028. When an issue arises, a complete replacement will be required. The unit will be down for 18 weeks while a new system is being engineered, built, and installed.

- The unit will require a one week outage to procure and install an obsolete part if a part were to fail and spares were not purchased.
- Spare obsolete parts will be difficult to procure after five years of being obsolete. A four week outage will occur if an obsolete part were to fail.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes, Like kind
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	No 2014
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

Environmental Affairs is currently reviewing this project.

- **Risks**

  - The TCS controls the turbine, generator, and balance of plant related to the steam turbine generator and as such is a large program. There is always risk that logic will be missed resulting in component damage. That risk is mitigated by hiring a seasoned owners engineer, an extensive factory acceptance test, and thorough commissioning testing.

  - There is some risk that the project costs could be greater than expected, and that risk has been mitigated by developing a detailed technical specification that has been used in the bid process, and including a reasonable amount of contingency based on experience from similar projects.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC 2 Turbine Controls Upgrade project for $1,063k net ($1,416k gross) to upgrade the turbine control system on Trimble County unit 2 and ensure long term unit reliability.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Base Price
Operator Station
Engineer Station
Spare Parts
Spare Part Obscelenece
Historian
Construction/Demolition
Construction Management
I/E Training Training
Engineer Training
Owner's Engineer
CIP Compliance
Redundant CV control
Internal Labor/Travel
Additional FAT testing
EHC Flush
Cisco Switch
Total

Investment Proposal for Investment Committee Meeting on: May 30, 2017

Project Name: TC2 Boiler Water Wall Replacement   **Arbough**

Total Approved Expenditures: $7,003k gross, ($5,251k net) (including contingency of $150k gross ($113k net)) (Approved on 09/01/2016 - See Appendix A)

Total Revised Expenditures: $8,350k gross, ($6,263k net) (including contingency of $150k gross ($113k net))

Project Number(s): 152049LGE

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Francisco Maldonado

Reason for Revision

A revised proposal is required due to defects identified in the cladding on the water wall panels purchased for TC2 under the original approved project. The project was scheduled to be completed during the TC2 spring 2017 planned outage to help combat corrosion issues, which have been prevalent on the TC2 boiler water walls since it was originally commissioned. In preparation for the project's planned timeline and risk mitigation plan, Trimble County placed an order with ███████████████████████████████ for the supply of fifty-two (52) laser cladded replacement furnace sidewall panels on 7/29/16. Project progress meetings and site visits were conducted on a regular basis for several months leading up to the outage and no major issues with the project were identified until late December 2016. Cracks were identified on some of the tube panels during a site visit at the facility where the tube cladding work was being completed. The Trimble County project management team requested a work stop until a full root cause analysis (RCA) was completed to determine the extent of the damage. Upon completion of the RCA, ████ deemed the panels unfit for the intended service and since new panels could not be delivered in time to meet the outage schedule, the project was postponed until 2018. Given that the project was postponed and the boiler tubing is still susceptible to corrosion, a "do nothing" option in 2017 was not feasible. Extensive inspections to identify problem areas were conducted. The inspections concluded that, at a minimum, 150 Dutchmen would need to be installed and approximately 3,600 square feet (sf) of metal spray would need to be applied or refurbished to minimize the possibility of a tube leak associated with corrosion. This work is a temporary solution to protect the boiler tubing from corrosion-related failures until the 2018 planned TC2 outage, when the project will be completed and the new clad water wall tubing will be installed.

An overview of the additional costs incurred and the reason for the revision to this project are highlighted in the attached table, "TC2 Boiler Water Wall Replacement Project Budget Overview." The corporate RAC approved the additional funding needed in 2017 as part of the 3+9 forecast. There will be $2,090k gross ($1,568k net) in 2018 that will be reallocated from other projects in the plant to help fund the additional costs of this project. The balance for 2018 will be managed by the corporate RAC as part of the 2018BP cycle.

Financial Summary   **Arbough**

Financial Summary ($000s):	Approved 9/1/2016	Revised	Explanation
Discount Rate:	6.5%	6.5%	
Capital Breakdown:			
Labor	$ 0	$ 75	
Contract Labor (Pressure Parts):	$ 3,108	$ 3,485	Accounts for monies spent in the installation of Dutchmen in 2017.
Contract Labor (Metal Spray):	$ 500	$ 1,404	Accounts for additional spray in 2017 and tie-in spray in 2018.
Contract Labor (Scaffolding)	$ 500	$ 952	Accounts for scaffolding needed again in 2018
Materials:	$ 2,700	$ 1,924	Anticipate receiving credit for damages. Accounts for additional material used for Dutchmen ($77k), labor to install additional Dutchmen ($377k) and additional metal spray install ($323k).
Local Engineering:	$ 45	$ 360	
Contingency:	$ 150	$ 150	
Reimbursements:	($1,752)	($2,087)	
Net Capital Expenditure:	$ 5,251	$ 6,263	
NPVRR:	$ 6,405	$ 6,948	

Financial Detail by Year - Capital ($000s)	Pre-2017	2017	2018	Post 2018	Total
1. Capital Investment Proposed	375	2,094	3,074		5,543
2. Cost of Removal Proposed			720		720
3. Total Capital and Removal Proposed (1+2)	375	2,094	3,794	-	6,263
4. Capital Investment 2017 BP	150	5,026			5,176
5. Cost of Removal 2017 BP		75			75
6. Total Capital and Removal 2017 BP (4+5)	150	5,101	-	-	5,251
7. Capital Investment variance to BP (4-1)	(225)	2,932	(3,074)	-	(367)
8. Cost of Removal variance to BP (5-2)	-	75	(720)	-	(645)
9. Total Capital and Removal variance to BP (6-3)	(225)	3,007	(3,794)	-	(1,012)

Financial Detail by Year - O&M ($000s)	Pre-2017	2017	2018	Post 2018	Total
1. Project O&M Proposed					-
2. Project O&M Pre-2017 BP					-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-	-

Conclusions and Recommendation **Arbough**

It is recommended that the Investment Committee approve the TC2 Boiler Water Wall Replacement project for $8,350k gross ($6,263k net) to reduce forced outages and maintain unit reliability as per original design.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

TC2 Boiler Water Wall Replacement Project Budget Overview

Gross ($000s)	Original Project Budget	Spend To Date (Through S2017 Outage)	▉ Settlement	Net Project Additions	Revised Project Budget	Notes
Internal Labor	-	22	-	75	75	Lessons learned from gas project. Originally did not have this in the budget.
Contract Labor (Pressure part install)	3,108	377	(377)	-	3,108	$3,108k is for original overlaid panel install in 2017 - moving this to 2018. $377k spend during S2017 outage on dutchmen installation to be reimbursed by ▉
Contract Labor (Metal Spray Install)	500	905	(323)	582	1,082	400 ft^2 of metal spray would have been related to original project, so the remainder related to panel replacement is to be reimbursed by ▉ - $323k
Contract Labor (Scaffolding)	500	452	-	452	952	$452k spent in 2017 for inspection and work completed. $500k for scaffolding in 2018.
Material	2,700	577	(77)		2,623	$500k progress payment for overlaid panels paid in 2016. $77k is for material used during S2017 outage for dutchment install - to be reimbursed by ▉. The total material cost is not changing - other ▉ credits related to labor (dutchmen install and metal spray) are taken into account on those lines.
Local Engineering and Burdens	45	77	-	238	360	Lessons learned from gas project. Originally did not have this in the budget.
Contingency	150	-	-	-	150	No change.
Totals	**7,003**	**2,410**	**(777)**	**1,347**	**8,350**	

Appendix A

Investment Proposal for Investment Committee Meeting on: August 31, 2016

Project Name: TC2 Boiler Water Wall Replacement

Total Expenditures: $7,003k gross, ($5,251k net) (including contingency of $150k gross and $113k net)

Project Number(s): 152049LGE

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Francisco Maldonado

Executive Summary

This proposal encompasses the requirements for the water wall replacement project for the Trimble County Unit 2 (TC2) boiler. TC2 is equipped with low NOx burners and, as such, it is susceptible to higher corrosion rates near the over fire air elevations at its side walls. ████, the Original Equipment Manufacturer (OEM), anticipated some elevated levels of corrosion and, as such, took proactive measures to protect against it by installing Amstar 888 (metal spray). Inspections during the TC2 2016 spring outage found evidence of the Amstar coating failing. As a result, the parent tube metal became severely corroded and on five different instances, led to boiler tube leaks and forced the unit to come off line. In an effort to reduce the risk of another unit outage, ninety-nine (99) tube sections (Dutchmen) were cut out and new tubes were installed where corrosion was the most prevalent. Amstar was applied to the remaining areas. This project will replace the diminished tubes with new weld overlaid tubes. The weld overlay material will be high chrome content Inconel, which helps improve corrosion resistance and has better bonding properties than the metal spray. The project will cover 2,500 square feet on each wall (left and right). Metal spray will also have to be added at the boundary lines where the weld overlay and existing Amstar meet. This is due to the fact that at least four to six inches of metal spray will have to be removed to properly prepare the weld area for the new panels.

The total project cost is estimated to cost $7,003k gross ($5,251k net). Based on the timing of this scope of work identified during the TC2 2016 outage inspections, this project was not included in the 2016BP. There is a total of $6,801k gross ($5,101k net) in 2017 included in the proposed 2017BP, and $200k gross ($150k net) in 2016 spending, which has been approved by the RAC in the 2016 6+6 FC.

Background   **Arbough**

The TC2 boiler is a once-through unit that is comprised of small diameter tubes arranged at a 25º spiral at its water walls. The water wall tube material is SA213 T12 with chromium specifications between 0.8% and 1.25%. In 2014, TC2 was equipped with new low NOx burners to meet the contract requirements set forth in the construction phase of the unit. The Low-NOx combustion system aids in meeting the NOx requirements for the unit. The burner design and intended operation is one which creates a reducing atmosphere within the furnace. In particular, it creates a reducing atmosphere at the boiler side walls between elevations 570' and 620'. These reducing conditions prevent the formation of a protective iron oxide scale on the water wall tubes.

The lack of a protective oxide scale layer exposes the tubes to the corrosive conditions in the atmosphere and eventually leads to wall loss on the tubes. The high water pressure in the tubes and the tube wall loss eventually lead to water wall tube leaks. In 2016, before the spring outage, the unit experienced five separate tube leaks due to corrosion. We anticipate that this trend will continue to rise if proper action is not taken to help protect the tubes from corrosion.

Inspections during the spring 2016 outage showed tubes which had experienced 50% wall loss. Therefore, ninety-nine Dutchmen were installed to replace thinned tubes. This project will replace the remaining diminished tubes with new weld overlaid tubes. The weld overlay material will be high chrome content Inconel. The high chrome (22%) helps combat corrosion issues and it has better bonding properties than metal spray. The weld overlay will be nominally 60 thousands of an inch.

- **Alternatives Considered**

    1. Recommendation (2500 sf on side walls, 5,000 sf total): NPVRR: ($000s) <u>$6,405</u>

    2. Replace only 2500 sf: NPVRR: ($000s) <u>$8,571</u>

        This option is not recommended as it leaves a large amount of corroded water wall tubing in the furnace which has the potential to fail and cause a unit outage. Furthermore is has a less favorable NPVRR than the recommendation.

    3. Do Nothing: NPVRR: ($000s) <u>$6,901</u>

        This option is not recommended because it leaves the water tubing exposed to further corrosion and it is likely that a tube leak related outage will occur.

Project Description

- **Project Scope and Timeline**

This project is scheduled to be completed during the TC2 outage starting in late February 2017. The material shall be on site no later than February 1, 2017. The weld overlay proposed for the panels is a high chrome content Inconel, which has been proven in the industry to protect against corrosion. Furthermore, the Inconel has a better bonding properties than does a metal spray. It is a welding process as opposed to a mechanical bond process and therefore does not spall. Many utilities including those in our own fleet have used the weld overlaid panels and have done so with success. Based on the issues experienced on TC2, we believe that this is a more reliable option than metal coatings. The timeline below highlights the anticipated project milestones from inception to completion.

Project timeline:

- Material Purchase: August 2016
- Award Install Labor: August 2016
- Award Scaffolding Labor: September 2016
- Start of Panel Fabrication: September 2016
- Award Metal Spray Install: October 2016
- Material Delivery: January 2017
- Start Outage: February 2017
- Complete Project March 2017

- **Project Cost**

The project costs are based on competitive bids received for the material and labor. Both the scaffolding and metal spray prices are based on historical pricing of similar projects. Both the scaffolding and metal spray install will each be competitively bid. The contingency includes potential risks associated with the pressure part install, scaffolding and metal spray installation. Given the size and history of the unit, we believe that there is a potential for unknown issues to arise, particularly with the welding of the blocks to the straps and potential rework at the headers stub pieces.

Economic Analysis and Risks

- **Bid Summary**

Material Bid Summary

The material purchase was sent out for bid. Five contractors were solicited for bids including ███ declined to participate in the request for quotation. ███████████ were competitively priced but could not meet our delivery requirements or panel

specification. For the purpose of this proposal we used the ▮▮▮▮▮▮▮▮▮▮▮ bid. Although the OEM, ▮▮ offers crucial knowledge and added value in the fabrication process of the panels. They are able meet the original specifications for the water walls and understand the nuances and specific characteristics of the furnace (spiral wound design). The ▮▮ position is further reinforced by their ability to supply the blocks and stub tubes already welded to the panels which will make the installation process more manageable. There are 2,400 blocks that would have to be welded in the field. The other bidders declined to bid on the blocks and the installation of the blocks. The previous ▮▮ performance on TC2 with the burner install and the balance header work has proven that they are able to provide quality components with precise fit-up. Partnering with ▮▮▮▮▮▮▮▮▮▮▮ will help minimize unforeseen issues and help complete this project within the small outage window proposed.

Material Bid Table

MBE/WBE	
Tubing	
Blocks	
Lead Time	
Total Cost ($000s)	

Labor Bid Summary

The install labor for the pressure parts was submitted on July 17th to five bidders. Contractors which were solicited include ▮▮ The early evaluations indicate that ▮▮▮ proposal offers the best value proposition. The evaluation team will be conducting bid reviews with a short listed group made up of ▮▮▮▮▮▮▮▮ This analysis utilizes ▮▮ proposal due to their effective response to major risk factors identified and their exemplary work experience within their recommended craft labor. ▮▮ proposed personnel for the job have had many successful jobs on TC2 including burner replacements, roof tube replacements and transition replacements. Their bid meets the specifications set forth in the SOW and we believe they are the most competent and capable team to complete this work in a safe and timely manner. Additionally, their rigging plan provides the safest option for staging the new panels and removing the existing ones. Their proposal is to mobilize the panels outside of the furnace as opposed to inside the furnace where scaffolding is installed.

▮▮▮▮▮▮▮▮▮▮▮ were invited back for a bid review and further clarification on their respective scopes. ▮▮▮ provided a comprehensive and attractive proposal. They demonstrated that they understood the criticality of the project schedule and complexity of the installation and rigging process. ▮▮ also provided an exceptional proposal. Their rigging plan and installation process was far more superior to what the other contractors provided. ▮▮▮ provided a proposal which included an inherently risky rigging plan. Their plan included the removal and reinstallation of furnace scaffolding every time a panel has to be removed or reinstalled. The furnace scaffolding is an engineered scaffold and designed to meet the access

needs of the project. If major modifications are required then re-engineering will be required as well. This is not a viable option as this would increase cost to LG&E and pose a significant safety risk. For the reasons stated above, ▇▇▇ was eliminated for further consideration and ▇▇▇ proposal is being used for this project request.

The scaffolding and metal spray labor will be bid out. We have used budgetary numbers based on previous projects of the same magnitude.

Labor Bid Table

Total Price ($000)	
Mobilization	
Labor	
Material	
Equipment	
Misc.	
Other	
Schedule	
Man Hours	

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	150	4,401			4,551
2. Cost of Removal Proposed		700			700
3. Total Capital and Removal Proposed (1+2)	150	5,101	-	-	5,251
4. Capital Investment 2016 BP	-	-			-
5. Cost of Removal 2016 BP					-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(150)	(4,401)	-	-	(4,551)
8. Cost of Removal variance to BP (5-2)	-	(700)	-	-	(700)
9. Total Capital and Removal variance to BP (6-3)	(150)	(5,101)	-	-	(5,251)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Although Project
Project Net Income	$0	$178	$259	$247	$235	$3,875
Project ROE	0.00%	6.40%	8.20%	10.00%	10.00%	9.70%

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:

  Contract Labor (Pressure Parts): $3,108
  Contract Labor (Metal Spray): $ 500
  Contract Labor (Scaffolding): $ 500
  Materials: $2,700
  Local Engineering: $ 15
  Burdens: $ 30
  Contingency: $ 150
  Reimbursements: ($1,752)
  Net Capital Expenditure: $5,251

- **Assumptions**

  It was assumed that if a tube leak occurred, it would cost approximately $100k to repair and it would take at minimum 4 days to repair. This case was assumed for both alternate options.

  It is assumed that this project will take care of most of the high risk areas, and it is anticipated that more will be identified during the 2017 inspection.

- **Environmental**

	New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.	
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	NO
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes/Yes
#3	Does the project increase through-put with any of the material handling systems?	NO
#4	Will the project affect the dispatch order or utilization of the unit?	NO
#5	Does the project increase the emissions unit's maximum hourly heat input?	NO
#6	Does the project increase the emissions unit's electrical output (gross MW)?	NO
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes 2016 (repaired)
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	Yes

The above was verified by Environmental Affairs

- **Risks**

Prior to the TC2 2016 spring outage, five separate tube leaks were identified due to the corrosion issue noted in this proposal. Two of the leaks lead to unit forced outages. The other three were found when the unit was in the process of being brought down or started back up. If the water walls are left as is, there is a certain possibility that the unit will suffer many more forced outages.

If tubing is not ordered in time, we run the risk of not meeting the proposed outage window. Additionally, we run the risk of having to pay expedited premiums if we place an order too late.

Conclusions and Recommendation   **Arbough**

It is recommended that Investment Committee approve the TC2 Water Wall Replacement project for $5,251k (net) / $7,003k (gross) to ensure long term unit reliability.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:</u>

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman, CEO and President

Combined Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: TC2 HP-IP TURBINE BLADES

Total Investment Expenditures: $1,650k (gross), $1,237k (net) (including 5% contingency)

Total Sole Source Contract Expenditures: $1,489k (including 5% contingency)

Project Number(s): 152099LGE

Business Unit/Line of Business: Power Generation - Trimble County Generating Station

Prepared/Presented By: Tyler Turner

Executive Summary

This project involves the sole source procurement of the first and second stage turbine blades for Trimble County Unit 2 (TC2) high pressure (HP) turbine section and intermediate pressure (IP) turbine section. Discussions with the ▮▮▮▮ and ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮ turbine experts regarding TC2 HP turbine section revealed that there is a likelihood the 1st and 2nd stage blades will show considerable solid-particle-erosion (SPE). ▮▮▮▮ is aware of this issue as it was encountered during the turbine overhauls of TC2 "sister" units that were performed by ▮▮▮▮ ▮▮▮▮ indicated that TC2 would likely experience the same issue.

Moreover, there were a few occurrences in which the TC2 HP turbine section 1st and 2nd stage blades were exposed to elevated main steam temperature. The concern is there is a small risk that the blades and/or rotor wheels[1] experienced thermal stress cracking during these temperature excursions. New blades will be required if either the blades or the rotor wheels indicate stress cracking as the blades cannot be repaired nor reused due to their metallurgical properties.

▮▮▮▮ also issued a report for TC2's IP turbine section 1st and 2nd stage rotating blades detailing concerns with cover lifting. ▮▮▮▮ engineering links this condition to the steam characteristics in this area and possibly inadequate tenon design. ▮▮▮▮ indicates that TC2's IP turbine will very likely experience this issue and advised that the station procure the 1st and 2nd stage blades now in preparation of replacing them.

Based on the available information regarding the issues, LGE's Generator-Turbine group advised the station to procure the 1st and 2nd stage blades now in preparation of replacing them as early as the 2018 major outage. Procuring the 1st and 2nd stage blades for both the HP and IP turbines offers a significant increase to the unit's operational availability; thereby, considerably reducing the Company's overall financial risks. Alternatively, electing not to proceed with blade procurement would delay repairs by up to 60 weeks in the event either of the above issues are discovered during inspections; the manufacturing lead time is 60 weeks for either set of blades.

The project's capital investment totals $1,237k (net) and includes a small five percent contingency as this is a firm bid for materials. The 2017BP includes $901k (net) and the remaining $336k (net) is to be covered by allocation from other projects in the plant's capital budget and approved through the Resource Allocation Committee (RAC).

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[1] Refer to Appendix A for detailed schematic of the turbine rotor assembly.

Background

In addition to TC2's HP turbine section SPE concerns, there are concerns regarding main steam (MS) overheating events also affecting the 1st and 2nd stage blades. These events mostly stemmed from the tuning surrounding TC2's MS temperature control scheme. TC2's MS temperature is effectively controlled by regulating feed water flow into the economizer and the initial tuning allowed for less than satisfactory MS temperature control under certain unit conditions. Note that measures were taken to address this issue.

The concern with overheating is that there is a risk of stress cracking in the turbine rotor wheels and the turbine blades. ████ and structural analysis firm ███████████ both suggest that there is a minimal risk of over stress to the 1st and 2nd stage rotor wheels and turbine blades. However, removal of the turbine blades will be required if integrity testing in 2018 reveals stress cracking in the wheels or blades. Turbine blade replacement is required in the event we determine stress cracking has occurred as this mechanical degradation mechanism cannot be repaired. Blade replacement will also be required even if stress cracking is isolated to the rotor wheels; the turbine blades cannot be reinstalled due to their material composition.

████ report for TC2's IP turbine section 1st and 2nd stage rotating blades detailed concerns with cover lifting or blade covers separating from the blades. ████ engineering links this condition to the steam characteristics in this area and possibly inadequate tenon design; tenons are an integral part of the blade and are intended to firmly secure the covers to the blades. The intentions are to inspect the covers for lifting and perform ultrasonic testing (UT) during the 2018 spring outage. Blade replacement is required in the event lifting or tenon integrity issues are discovered.

Furthermore, there are concerns that the IP turbine section 1st and 2nd section stage blades will exhibit signs of SPE. Note that SPE is to be expected in the IP section just as it is expected in a subcritical unit due to the operational characteristics of the boiler reheat section. Therefore, the intention is to procure coated turbine blades for both the HP and IP so minimize the effects of SPE and the need to prematurely replace the 1st and 2nd stage turbine blades in the future.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $ 2,242

  2. Do Nothing: NPVRR: ($000s) $ 124,584
     Do not perform an inspection during the 2018 spring outage to determine the extent of the described issues. In the event one of the described issues results in failure, then more than 60 weeks of downtime is to be expected due to the extended manufacturing lead time; the current lead time for either set of turbine blades is 60 weeks. Note this does not consider the added repair cost and downtime due to damage that is certain to occur from the failure.

  3. Alternative 2 Procure Following Inspection: NPVRR: ($000s) $ 5,263
     Perform an inspection during the 2018 spring outage to determine the extent of the described issues. Electing to procure blades following the inspection of the HP & IP turbines would result in more than 60 weeks of outage time due to the extended manufacturing lead time.

Project Description
- **Project Scope and Timeline**
  Project Scope:
  - Procure the 1st and 2nd stage HP rotating blades

o Procure the 1st and 2nd stage turbine end and generator end n rotating blades

Timeline

o December 2016 – Provide Vendor PO to begin manufacturing the six (6) sets of turbine blades.
o March 2018 – Six (6) sets of turbine blades delivered to TC Generating Station.

- **Project Cost**
  - o HP 1st Stage Blades, Coated   - $252k (gross), $189k (net)
  - o HP 2nd Stage Blades, Coated   - $194k (gross), $146k (net)
  - o IP 9th Stage Blades TE, Coated   - $336k (gross), $252k (net)
  - o IP 9th Stage Blades GE, Coated   - $336k (gross), $252k (net)
  - o IP 10th Stage Blades TE, Coated   - $266k (gross), $199k (net)
  - o IP 10th Stage Blades GE, Coated   - $266k (gross), $199k (net)

    - **Total Project Cost**   -   **$1,650k (gross), $1,237k (net)**

Economic Analysis and Risks

- **Bid Summary**

  TC2's higher than normal (i.e. sub-critical unit) operating pressures and temperatures coupled with ███████ designed blades results in a lack of information within the industry (e.g. ███████████) regarding blade metallurgy and geometry. Therefore, a bid summary is not available as ███████████ is currently the only source for these turbine blades.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	124	618	495	-	1,237
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	124	618	495	-	1,237
4. Capital Investment 2017 BP	-	784	117	-	901
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	-	784	117	-	901
7. Capital Investment variance to BP (4-1)	(124)	166	(378)	-	(336)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(124)	166	(378)	-	(336)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-			-
2. Project O&M 2017 BP	-	-			-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 0
Contract Labor:	$ 0
Materials:	$ 1,418
State Tax	$ 85
Local Engineering:	$ 30
Burdens:	$ 38
Contingency (5%):	$ 79
Reimbursements:	$ (412)
Net Capital Expenditure:	$ 1,237

- **Assumptions**

  o Recommendation – Availability Dis-improvement of zero weeks and maintain continued operation as prescribed by Generation Planning. Probability % - HP & IP blade SPE degradation and IP blade cover failures were modeled as a Weibull (exponential) failure rate function. Data regarding turbine blade failure rates is nonexistent but there is strong evidence from similarly designed units that TC2 will likely experience the same described issues. Therefore, one may reason that the blades are at the onset of their *Wearout Life* in which failure rate increases (exponentially) with time and model it as such.

  o Do Nothing – In the "do nothing" approach, it is assumed that the the baldes are not produred, and the unit runs until failure. There is an availability dis-improvement of 52 weeks each year with an increasing probability until it reaches 100% in 2027. At that point, the blades are purchased and the unit is unavailable for a total of 64 weeks (60 week lead time for the turbine blades and 4 weeks for turbine assembly) – 52 weeks in 2026 and 12 weeks in 2027. Probability % – Same as described in *Recommendation* assumptions. A 2% inflation rate is assumed for the blades.

  o Alternative #2 Procure Following Inspection – Availability dis-improvement of 52 weeks in 2016 thru 2018 and 24 weeks in 2019. The 24 weeks in 2019 is the remaining time of the 64 weeks (60 week lead time for the turbine blades and 4 weeks for turbine assembly) necessary to procure and assemble the turbine following the discovery of issues during the 2018 spring outage inspection. Probability % – Same as described in *Recommendation* assumptions. A 2% inflation rate is assumed for the blades.

- **Environmental**

  There are no environmental implications.

- **Risks**
  o Recommendation → minimal if either of the issues described in this proposal are discovered.
  o Do Nothing → catastrophic failure of a turbine blade resulting in additional turbine damage and the complete loss of TC2 generation for an extended period of time potentially well beyond 64 weeks; thereby significantly increasing the Company's overall financial risk.
  o Alternative #2→ Procuring Following Inspection → complete loss of TC2 generation capacity for up to 64 weeks if either of the two issues described in this proposal are discovered.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the TC2 HP-IP Turbine Blades project though $1,650k gross ($1,237k net) to increase the operational availability of the unit and significantly reduce the Company's overall financial risks.

In addition, it is recommended that the SSA with ███████████ for $1,489k be approved for the turbine blades due to lack of available information regarding the blade metallurgy and geometry; the station will reverse engineer the turbine blades to allow for competitive bidding for future needs.

Please see the attached Award Recommendation Approvals page for additional proponent and Supply Chain or Commercial Operations approvals.

Approval Confirmation for Capital Project Spend and Contract Authority Greater Than or Equal $1 million sole sourced:

The Capital project and Sole Source Contract spending authority included in this Investment Proposal have been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project and Sole Source Contract spending request.

_____

Kent W. Blake
Chief Financial Officer

_____

Victor A. Staffieri
Chairman, CEO and President

AWARD RECOMMENDATION APPROVALS
– Attachment for IC Proposal

SUBJECT:
Sole Source Authorization - TC2 HP-IP Turbine Blades Contract

Please see the attached Investment Proposal for information related to this contract authority request and additional approvals.

RECOMMENDATION/APPROVAL The signatures below recommend that Management approve the TC2 HP-IP Turbine Blades procurement contract for $1,489k to ██████████

Proponent/Team Leader Tyler C. Turner		Manager Larry Byrd	
Manager - Supply Chain or Commercial Operations Charles Ransdell		Director – Supply Chain or Commercial Operations Joseph Clements	
Director Jeff Joyce		Vice President Ralph Bowling	

Note: For Contract Proposals greater than $4 million bid, or greater than $1 million sole sourced, additional required approvals are included as part of the attached Investment Proposal.
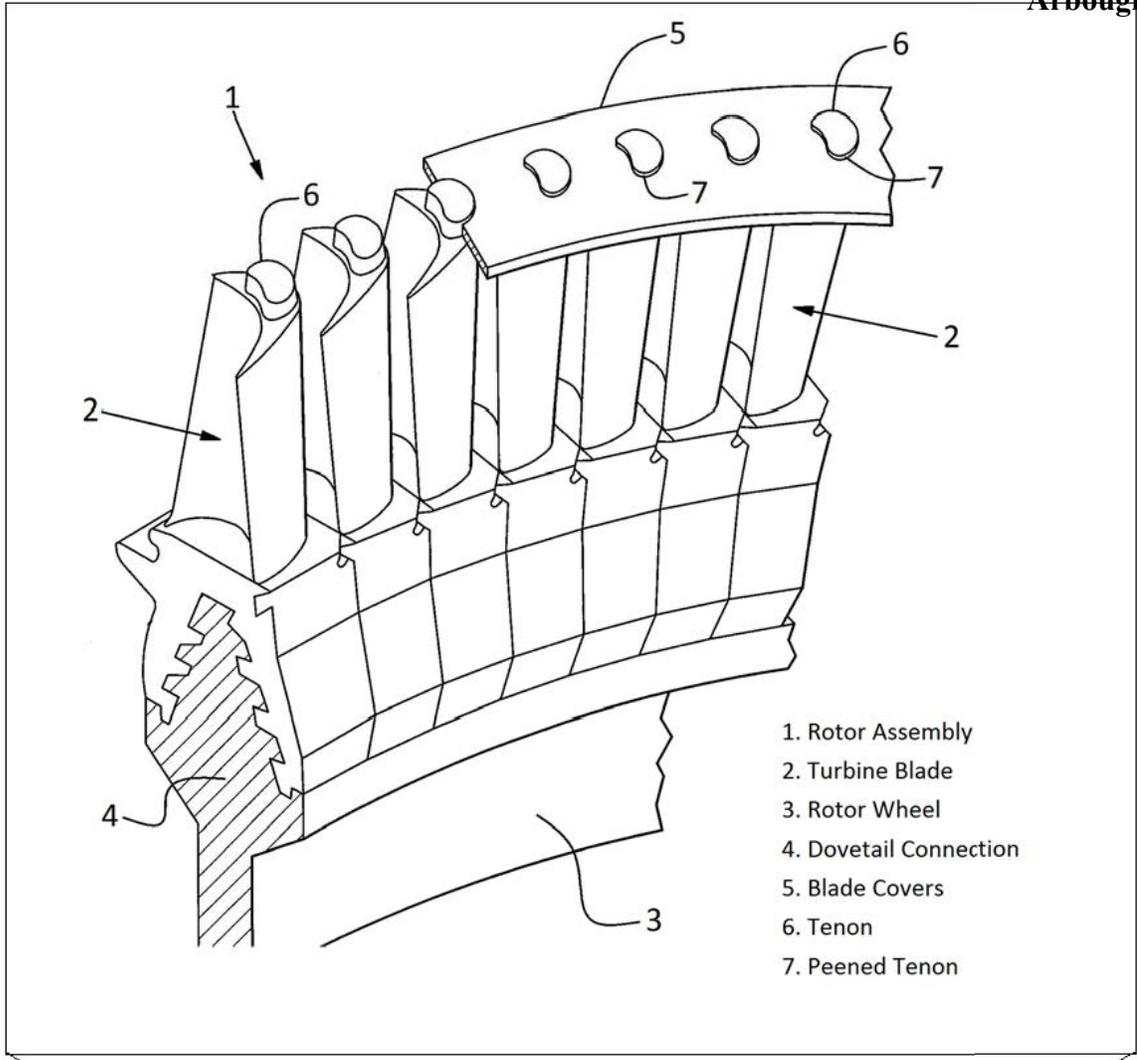
1. Rotor Assembly
2. Turbine Blade
3. Rotor Wheel
4. Dovetail Connection
5. Blade Covers
6. Tenon
7. Peened Tenon
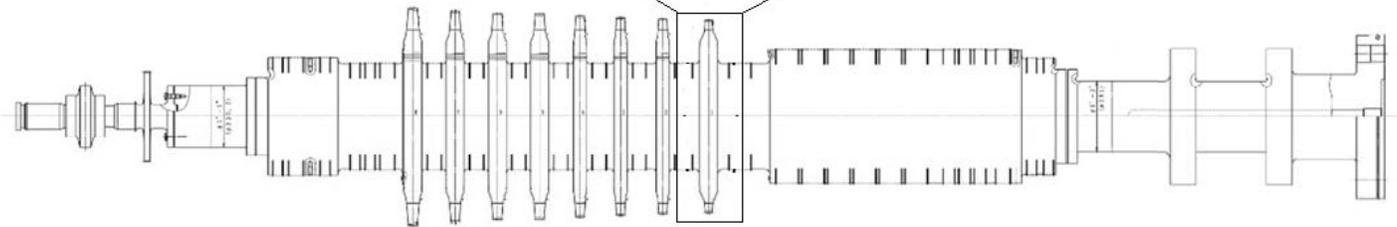
TC2 HP Turbine Rotor

Investment Proposal for Investment Committee Meeting on: August 30, 2017

ProjectProject Name: TC2 PJFF Bag and Cage Replacement

Total Expenditures: $2,793k gross($2,095k net),(including 10% contingency of $225k gross ($167k net))

Project Number(s): 135245LGE/135245KU

Business Unit/Line of Business: Power Generation

Prepared/Presented By: Haley Turner

Executive Summary

The Trimble County 2 (TC2) Pulse Jet Fabric Filter (PJFF) was placed into service in January 2011, when the unit was commissioned. The PJFF has 12 compartments with approximately 1,100 bag and cage pairs per compartment. This is a total of approximately 13,200 bag and cage pairs.   The bags and cages are 26' in length and 5" in diameter. They are fiberglass bags with a Teflon membrane. The bags were replaced in 2014, but the cages were not replaced at that time unless damaged.

The scope of this project includes the purchase and installation of the filter bags and cages in the TC2 PJFF. The removal and disposal of the old bags and cages is included as well. The project also includes a fluorescent leak test to verify proper installation and pre-coating with perlite. The perlite adds a thin protective powder layer to the new bags to protect them during initial start up conditions. The particulate matter (PM) limit on TC2 is 0.015 lb/MBTU, which is half of the Mercury and Air Toxics Standards (MATS) limit for all the other units. This limit was one of the stringent state requirements to construct TC2 and preceded the MATS requirements. This limit is extremely low, and does not allow for a significant number of broken bags. If the bags are not changed out in the 2018 outage, maintaining PM compliance will become more difficult. The unit would need to be load limited and additional outages will be required. The option to change the bags in one compartment at a time would decrease the life of the new bags due to the majority of the air flow going through these new, more permeable bags.

A total of $2,095k net was included in 2018 in the 2017BP. A total of $500k gross ($375k net) in 2017 was funded as part of the RAC approved 3 and 9 forecast.

Background

The TC2 coal-fired unit at the Trimble County Generating Station began commercial operation on January 22, 2011. The unit has a PJFF which contains approximately 13,200 filter bags and cages across twelve compartments. The bags are 5" diameter and 26' long. During original construction, ▇▇▇▇ installed 16 oz/yd Acid Resistant Fiberglass bags with a polytetrafluoroethylene (PTFE, commonly known as Teflon) membrane. Five compartments of bags were replaced in September, 2011 due to ash bridging issues which overheated the bags. The new bags installed were 22 oz/yd Acid Resistant Fiberglass bags, which ▇▇▇▇ recommended for long-term strength. Another 1,000 bags were replaced due to failure between fall 2012 and fall 2013. All bags were replaced in the spring of 2014. The cages were not replaced unless they were damaged or broken.

The pressure drop across the fabric filter on TC2 was extremely high due to high gas flows and high air to cloth ratio. The high differential pressure (dP) this caused required more frequent pulse cleaning of the bags.   This increased pulsing caused the bags to fail prematurely. The bags were in operation for only 2.5 years before they had to be replaced the first time. The gas flows were decreased significantly with the installation of the new burners on TC2. The air to cloth ratio is still higher than the industry standard. This higher ratio causes the PJFF to operate at a high dP resulting in more pulsing than ideal. Due to this dP, the bags have begun to show failures.

Sample bags have been sent out for testing during each outage, and the permeability and strength monitored over time. The Company has also conducted leak tests with fluorescent powder. Due to these tests, results showing degradation and the increasing amount of broken bags found during outages, it is necessary to replace the bags during the next outage in order to ensure the continued reliability of the unit. The bags will be in service for 4 years next spring.

The cages were not replaced during the last bag replacement and they have reached the end of their lifespan. They are now becoming more brittle and bent. Broken cages will damage the new bags if not replaced during the 2018 outage.

Installation of new bags and cages will allow the unit to continue operating as necessary for PM removal rates.

- **Alternatives Considered**
  1. Recommendation: Install new bags and cages   NPVRR: $2,396k
  2. Alternative #1: Delay Project One Year   NPVRR: $2,572k
  3. Alternative #2: Do Nothing   NPVRR: $8,432k

  Recommendation – Install New Bags and Cages
     The purchase and installation of new bags and cages in the 2018 outage is the recommended project. This plan is least cost over the life of the project and avoids the probability of unit outages and decreases in PM removal efficiency.

Alternative 1 – Delay project one year

Delay of the bag and cage change-out one year to the next planned unit outage presents two large risks: decreased PM removal efficiency and risk of unit outages due to environmental compliance. As bags start to fail, the failure will accelerate exponentially leading to PM compliance issues. This alternative is not recommended due to the above risks and unfavorable NPVRR.

Alternative 2 – Do Nothing

This alternative is not recommended as this would be extremely detrimental to unit operation and condition with high probability of unit forced outages.

Project Description

- **Project Scope**

The scope of this project includes the purchase and installation of new bags and cages which will replace the current bags and cages in the TC2 PJFF. This will occur during the planned spring outage in 2018 for TC2. The supply of new bags and cages is being competitively bid and an order will be placed in the 3rd quarter of 2017. The removal of the old bags and cages as well as the installation of the new bags and cages is also included in the scope being competitively bid, as well as the disposal of all the old bags and cages.

We are using the spare bags and cages in storage that were purchased during the 2014 outage for this project. We currently have approximately 2,100 cages and 1,150 bags in storage. We will be replacing a number of these with new spare bags and cages. We will also be replacing the access door gaskets as part of this project. Leak-testing with fluorescent powder to ensure proper installation and pre-coating with perlite to protect new bags is also included in the project.

- **Project Scope and Timeline**

The following details the expected project timeline:
- July 2017   Bids received for bags and cages and installation
- September 2017   Issue PO for new bags and cages and installation
- February 2018   Delivery begins for bags and cages
- March 2018   Outage starts, work begins
- April 2018   Installation complete
- April 2018   Leak test and pre-coating complete

- **Project Cost**

The total cost of the project is $2,793k gross ($2,095k net), which includes $225k gross of contingency. The project also includes $319k gross burden. Values of plant labor, disposal and other material portions of the project are estimates from past projects. The bags and cages are estimated to be a maximum of $1,313k based on recently received bids. The contractor costs for removal and installation are estimated to be a maximum of $429k based on recently received bids.

Economic Analysis and Risks

- **Bid Summary ($000s)**

Bags	
Cages	
Freight	
Subtotal Material	
Removal	
Installation	
Subtotal Labor	
Total	
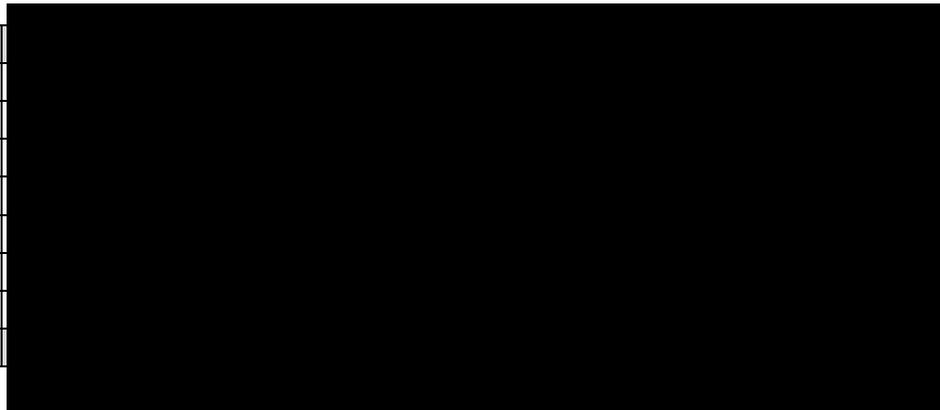
- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	375	1,527			1,902
2. Cost of Removal Proposed		193			193
3. Total Capital and Removal Proposed (1+2)	375	1,720	-	-	2,095
4. Capital Investment 2017 BP		1,991			1,991
5. Cost of Removal 2017 BP		104			104
6. Total Capital and Removal 2017 BP (4+5)	-	2,095	-	-	2,095
7. Capital Investment variance to BP (4-1)	(375)	464	-	-	89
8. Cost of Removal variance to BP (5-2)	-	(89)	-	-	(89)
9. Total Capital and Removal variance to BP (6-3)	(375)	375	-	-	-

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):   **Arbough**

Discount Rate: 6.3%

Capital Breakdown:

Labor:	$151
Contract Labor:	$428
Materials:	$1,451
Disposal:	$200
Local Engineering:	$20
Burdens:	$319
Contingency:	$225
Reimbursements:	($698)
Net Capital Expenditure:	$2,095

- **Assumptions**

For the proposed project to install new bags and cages, assumptions include capital spend occurring only in 2017 and 2018. Cost estimates are based on preliminary bids and historical costs for similar projects completed.

For the 'Do Nothing' alternative, assumptions included a 25% probability of one week of unplanned unavailability starting in 2018 and increasing by 25% each year. The probability would be 100% by 2021. Each year the probabilities increase due to more damage caused by pulsing and ash abrasion resulting in damage to the bags and cages.

For the Delay One Year alternative, the first assumption was that capital expenditures would occur in 2018 and 2019 (the next available outage year) and that costs would increase by three percent each year based on current 2017 pricing estimates. The next assumption was that there would be seven days of unplanned availability in 2018 at 25% probability.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	No
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	Yes 2014
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

Environmental is currently reviewing, but no issues are expected.

- **Risks**

The risks of not completing the project include:
- Failure to meet particulate emissions limit: TC2 is subject to a particulate emission limit of 0.015 lb/MBTU per day. If the filter bags are not replaced the particulate emissions will continue to increase and pose a risk to the unit's reliability.
- Outages: If the bags are not replaced the particulate emissions will continue to increase and the unit will have to take outages to replace sections of broken bags.
- Changing bags online: The bags could be changed one compartment at a time while the unit remains online, however, the life expectancy of the new bags would be greatly affected due to air flow taking the path of least resistance through the new, clean bags. Also, changing the bags online constitutes a higher risk in safety.

- **Conclusions and Recommendation** Arbough

It is recommended that the Investment Committee approve the TC2 PJFF Bag and Cage Replacement project for $2,793k gross, ($2,095k net) to continue to meet particulate matter emission limits and avoid unit outages.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Arbough

Investment Proposal for Investment Committee Meeting on: <u>April 26, 2017</u>

Project Name: <u>TC2 SCR CATALYST L3</u>

Total Expenditures: <u>$2,873k gross, ($2,155k net) (including contingency of $250k gross and $187k net)</u>

Project Number(s): <u>134113LGE/134113KU</u>

Business Unit/Line of Business: <u>Power Production / Trimble County 2</u>

Prepared/Presented By: <u>Haley Turner</u>

Executive Summary

The Trimble County 2 (TC2) Selective Catalytic Reduction (SCR) was placed in service when the unit was commissioned. The SCR is designed to hold three layers of catalyst and currently has all three layers utilized. Initial combustion issues created more NOx output from the boiler than designed requiring the third layer of catalyst to not only be installed earlier than planned, but a taller layer was installed to increase NOx removal capability. During the Spring 2014 outage, the top layer (Layer 1) of catalyst was replaced with a like-kind ▮▮▮▮▮ catalyst of the same original designed height. The original Layer 1 was regenerated and replaced the original Layer 2 in 2016. However, as catalyst sampling and testing continued, it was determined that the regeneration was not performing as predicted. In an effort to improve the catalyst management plan and better control catalyst life and performance, the decision was made to change the Trimble County catalyst management plan to utilize new catalyst modules.

The scope of this project includes removing the existing catalyst modules in Layer 3 and replacing them with brand new, plate type catalyst modules, a total of 182 new modules. The removed catalyst will be disposed of due to the past poor regeneration results of TC2 catalyst. If the catalyst is not installed, the SCR performance will degrade below the target removal rate for NOx emissions. Also, as the SCR catalyst deactivates further, the ammonia slip through the SCR will increase which accelerates air heater fouling and increases the risk of an unplanned outage to wash the air heater.

A total of $3,283k gross ($2,462k net) is included in the 2017BP for this project, with $502k gross ($377k net) in 2017 and approved by the RAC in the 2-10 forecast. The total requested project funding is $2,873k gross ($2,155k net) with 10% contingency. It is recommended that the project be approved in order to meet the target NOx emissions, reduce ammonia slip, avoid unplanned outages, and improve safety and timing for future catalyst replacement projects.

Background   **Arbough**

The TC2 SCR was placed in service when the unit was commissioned and is designed to hold three catalyst layers. The two layers were filled with catalyst initially, and the third, taller layer was added in 2012 due to boiler outlet NOx exceeding system design due to poor burner performance. In the Spring of 2014, the top layer (layer 1) of catalyst was replaced with brand new catalyst in order to meet SCR performance requirements and outage scheduling. The middle layer (layer 2) of catalyst was replaced in 2016 by the regenerated original layer 1. Based on the most recent catalyst test results, the bottom layer (layer 3) of catalyst must be replaced in 2018 in order for the TC2 SCR to meet NOx removal requirements and avoid unplanned outages due to ammonia slip plugging the air heater.

The current catalyst management plan, based on continued catalyst sampling and testing, shows a need for Layer 3 to be replaced in 2018 during the planned outage for TC2. Due to the results of the continued catalyst sampling and testing program, regeneration is not a viable option to ensure the catalyst management plan can be maintained. Sample testing results have shown that the regenerated catalyst modules are not performing to the guaranteed levels. This poor performance reduces the useful life of the catalyst for NOx removal and ammonia slip resistance. For these reasons, regeneration has been removed as a viable option for the TC2 catalyst management plan and therefore only new catalyst modules will be considered in the future for catalyst replacement projects. The third layer added in 2012 was taller than the other two original layers. Due to the improved burner performance, the third layer can be replaced with a thinner layer (same size of the other two layers).

Installation of a new layer of catalyst in Layer 3 will allow the unit to continue operating as necessary for NOx removal rates and reducing ammonia slip to the air heater which poses risk of air heater fouling if not controlled and minimized.

- **Alternatives Considered**
  1. Recommendation: Install new layer   NPVRR: $2,475k
  2. Alternative #1: Delay Project One Year   NPVRR: $3,505k
  3. Alternative #2: Do Nothing   NPVRR: $10,657k

  Recommendation – Install New Layer
  > The purchase and installation of a new layer in the 2018 outage is the recommended project. This plan is least cost over the life of the project and avoids the probability of air heater wash outages, unit derates, and decreases in NOx removal efficiency.

  Alternative 1 – Delay project one year
  > Delay of the catalyst layer change-out one year to the next planned unit outage presents two large risks: decreased NOx removal efficiency and risk of air heater wash outages due to ammonia slip. As catalyst activity deteriorates past the recommended replacement year the NOx removal efficiency declines. Additionally, the increasing ammonia slip would foul the air heaters faster than typical and poses risk of forced air heater wash outages. This alternative is not recommended due to the above risks and unfavorable NPVRR.

<u>Alternative 2 – Do Nothing</u>   **Arbough**

This alternative is not recommended as this would be extremely detrimental to unit operation and condition with high probability of unit derates/forced outages.

Project Description

- **Project Scope and Timeline**

The scope of this project includes the purchase of a new layer of catalyst modules which will replace the layer currently installed on Layer 3 of the TC2 SCR. This will occur during the planned outage in 2018 for TC2. The supply of new catalyst modules is being competitively bid fleet-wide and an order will be placed in the second quarter of 2017. The catalyst material will be delivered at least one month prior to the start of the outage. A total of 182 modules (91 per reactor) will be removed from Layer 3 and replaced with new modules.

The labor for removal and installation was bid as part of a fleet-wide initiative and was awarded earlier this year. New swing bolt-style doors will be purchased as part of this project and industrial cleaning of the SCR will also be completed. Disposal of this layer of catalyst and the layer removed in 2016 (in storage) will be included in this project. Additional seals and miscellaneous material will be purchased in the winter of 2017 for the catalyst replacement project.

The following details the expected project timeline:
- March 2017   Bids received for catalyst material
- April 2017   Issue PO for new catalyst material, progress payment
- 4th Quarter 2017   Issue PO for Industrial cleaning of the SCR
- 3rd Quarter 2017   Issue PO for new access doors
- March 2018   Outage start, catalyst replacement/door install completed
- April 2018   Used SCR catalyst shipped for disposal
- June 2018   Tune SCR to optimize ammonia distribution

- **Project Cost**

The total cost of the project is $2,873k gross ($2,155k net), which includes $250k gross of contingency for materials. The project also includes $125k gross in burdens (5%). Values of the labor and other material portions of the project are estimates from recent projects. The catalyst module material is estimated at $1,600k based on recently received catalyst bids.

Economic Analysis and Risks

- **Bid Summary**

The catalyst removal/installation labor was awarded as part of a fleet-wide bid which included change-outs scheduled during 2017 and 2018 at Mill Creek, Brown, Trimble County, and Ghent. There were no W/V/MBE bidders identified, and the bid was awarded to ███ in February 2017.

███████████████████████████████

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	377	1,653			2,030
2. Cost of Removal Proposed		125			125
3. Total Capital and Removal Proposed (1+2)	377	1,778	-	-	2,155
4. Capital Investment 2017 BP	226	2,111			2,337
5. Cost of Removal 2017 BP		125			125
6. Total Capital and Removal 2017 BP (4+5)	226	2,236	-	-	2,462
7. Capital Investment variance to BP (4-1)	(151)	458	-	-	307
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(151)	458	-	-	307

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 30
Contract Labor:	$ 518
Materials:	$ 1,950
Local Engineering:	$ 0
Burdens:	$ 125
Contingency:	$ 250
Reimbursements:	($ 718)
Net Capital Expenditure:	$ 2,155

- **Assumptions**

For the proposed project to install a new catalyst layer, assumptions include capital spend occurring only in 2017 and 2018. Cost estimates are based on catalyst bids and historical costs for similar projects completed.

For the Delay alternative, the first assumption was that capital expenditures would occur in 2018 and 2019 (the next available outage year) and that costs would increase by three percent each year based on current 2017 pricing estimates. The next assumption was that there would be six days of unplanned availability in both 2018 and 2019 with 50% and 90% probability, respectively. These probabilities are based on issues that will arise as ammonia slip and NOx emissions increase due to reduced catalyst activity. Six outage days are equivalent to two unplanned air heater washes. Air heater washes are estimated to cost $36,000 each, which would be an incremental cost of $72,000 per year in 2018 and 2019.

For the Do Nothing alternative, assumptions included 50% probability of six days of unplanned unavailability starting in 2018 and increasing to 90% in 2019 and 100% in 2021. Each year the probabilities increase due to ammonia slip and NOx emission issues from the aging catalyst. Six outage days are equivalent to two unplanned air heater washes. Air heater washes are estimated to cost $36,000 each, which would be an incremental cost of $72,000 per year. The cost of exceeding NOx emission targets was not included at this time due to the unknown nature of the NOx allowance market and our plan to self-comply to mitigate the risk.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	Yes a. Yes
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit?	Yes L3 added -2012

		a. Provide frequency or when equipment or component in question was last repaired or replaced.	L1 replaced – 2014 Arbough L2 replaced – 2016
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.		No

This project follows the TC2 Catalyst Management Plan

- **Risks**

    The risks of *not completing* this project include:
    Exceeding NOx emissions target: NOx removal performance will decrease as the catalyst layer deactivates with age. Without the replacement of a new catalyst layer in the TC2 SCR the NOx emissions will increase and will risk exceeding the Unit's NOx limit. Operating at the necessary NOx removal rate will become more critical due to compliance regulations associated with the finalization of CSAPR-II.

    Forced Unit Outages: Without replacement of a new catalyst layer in the TC2 SCR, the amount of un-reacted ammonia leaving the system will increase. This ammonia will then be available to form ammonia bisulfate which deposits in the air heater. The deposits will build-up over time and will require a unit outage for air heater cleaning which will increase O&M costs and negatively impact unit availability

A general risk for this project was found as a result of the recent outage and inspection on the TC2 SCR. During the process of removing routine catalyst samples, it was found that the second layer of catalyst is more brittle than expected. This is physically the oldest layer of catalyst in the TC2 SCR due to the fact is it an original layer that was regenerated. Multiple samples were taken from this layer and sent off for testing and evaluation. The catalyst planned for the third layer install could be used to replace the second layer if it is found to be in most need of a replacement after evaluation.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the TC2 SCR Catalyst L3 project for $2,155k (net) / $2,873k (gross) to ensure NOx removal continues to meet target removal rates and environmental regulations and to avoid forced outages and/or derates due to ammonia slip or NOx emission issues.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Paul W. Thompson
Chief Financial Officer	President and Chief Operating Officer

Trimble County Gas Turbine Hot Gas Path Inspection & Controls Platform Upgrade Although **Projects Contract Proposal**

Investment Proposal for Investment Committee Meeting on: November 24, 2015

Project Name: Trimble County Combustion Turbine Hot Gas Path Inspection & Controls Platform Upgrade Projects and Contract

Total Capital Expenditures: $31,389k (Including $3,138k of contingency)

Total O&M Expenditures: $2,430k (no contingency included)

Total Project Proposed: $33,819k

Total Contract Expenditures: ▇▇▇▇ (Including $2,754k of contingency)
Project Number(s): 132000, 132001, 132002, 132003, 132004, 132005 (HGPIs) 152001LGE, 152002LGE, 152003LGE, 152004LGE, 152005LGE, 152006LGE (Exciter) 140660LGE, 140658LGE, 140659LGE (LCI Upgrade), 152011LGE, 152012LGE, 152013LGE, 152014LGE, 152015LGE, 152016LGE (Mark VI Controls)

Business Unit/Line of Business: Generation - Trimble County Station

Prepared/Presented By: Charles Ransdell/ Laura Mohn/ Tomas Menezes/ Jeff Joyce

Executive Summary

This project and contract proposal is seeking authorization for the second round of hot gas path inspections (HGPIs) for all six (6) Trimble County ▇▇▇▇ simple cycle natural gas turbines (CTs). Units TC5 through TC10 are expected to reach nine-hundred factored starts since the first cycle of HGPIs within the 2016-2024 timeframe. HGPIs are required on these units in order to avoid risk of component failure associated with thermal fatigue. Component thermal fatigue is caused by rapid heating and cooling of parts in the combustion path as units are cycled with load.

Funding for controls upgrade projects included in the proposed 2016 BP for all six (6) CTs is also requested within this proposal. The existing ▇▇ platforms for the turbine controls (▇▇▇▇ ▇▇, generator excitation system, and the load commutator inverters (LCI) will become obsolete and unsupported within the next five years and need to be upgraded. These additional projects have been leveraged along with the HGPIs in the bidding and negotiating process and have resulted in favorable discounts to list pricing and positive budget variances.

This proposal recommends and requests approval for both the contract amount of ▇▇▇▇, the capital project amount of $31,389k and O&M expenditures of $2,430k to perform the HGPIs as well as the turbine controls, excitation, and LCI system upgrades discussed herein. The total request for capital investment and cost of removal is included in the proposed 2016 BP.

Background   Arbough

Trimble County Generating Station has six (6) ███████████████ frame ███ single fuel gas turbines. The units are designated TC5 through TC10. TC5 and TC6 were commissioned in 2002, and TC7 through TC10 were commissioned in 2004.

███ provides a detailed recommended maintenance schedule ███████ for major gas turbine components and issues Technical Information Letters (TIL), which is ███ method of communicating known wear and design issues. The Trimble units are operated as peaking units and are subject to the maintenance schedule based on factored starts. HGPIs are required at 900 factored start intervals to maintain reliable operation of the machines. All six of the gas turbines are currently forecasted to reach 900 factored starts since the first round of HGPIs within the 2016 to 2024 timeframe. This will be the second round of combustion component inspection and maintenance for these turbines. Peaking units experience their damage primarily from thermal fatigue cycles. The damage caused by thermal fatigue is very predictable. Exceeding 900 factored starts significantly increases the risk of catastrophic failure and will result in a higher percentage of unrepairable parts. In this case, replacement costs would exceed refurbishment costs. LG&E would increase their risk of equipment failure if the OEM's recommended maintenance schedule is not followed.

The Trimble CTs have three different control platforms that will become unsupported in the next five years. Each of the six (6) units' ███████ turbine control systems requires an upgrade to ██████ to address obsolescence/non-support in the equipment components. This is the first of three planned upgrades that will allow the systems to be supported through 2020. The last two upgrades are not available at this time. Also, each of the units' generator excitation systems ████████████ requires an upgrade to ██████. This will align the exciter with the turbine ███████ which will maintain support into 2020. Finally, pairs of the Trimble gas turbines (TC5/6, TC7/8 and TC9/10) share a load commutator inverter (LCI) that performs speed control or low current soft starting of the units. An upgrade is required on the three LCIs in order to maintain support and avoid obsolescence through 2020.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)** Arbough

    1. Recommendation: NPVRR: ($000s) $31,649

       Perform the HGPIs and control platform upgrades utilizing ▮▮▮▮▮▮▮ as the contractor along with recommended options outlined later.

    2. Do Nothing: NPVRR: ($000s) $138,101

       The "Do Nothing" alternative is to not perform the HGPIs or controls upgrades. In this case, the gas turbines will become inoperable, making this not a viable option.

    3. Next Best Alternative(s):   NPVRR: ($000s) $32,205

       The next best alternative is to perform the HGPIs and complete the controls projects as stand-alone projects. The 2016BP includes individual projects associated with each of these items, but pricing is better by combining them with the HGPIs.

Project Description

- **Project Scope and Timeline**

The scope for the HGPIs includes disassembly, inspection, replacement of parts, and reassembly. LKE's existing set of spare parts will be installed on the first machine, and the parts removed from the first unit will be refurbished for use on the second unit. This pattern will continue until all six machines have been completed. Upon conclusion of the HGPI projects, there will be a complete set of refurbished capital spare parts. Also included are all recommended repairs to address applicable Technical Information Letters (TILs), which is ▮▮ method of communicating known wear and design issues. A detailed list of the applicable TILs addressed as part of the HGPI is located in Appendix 1.

As part of the offering, the OEM and recommended vendor, ▮▮ presented other scopes for consideration, that they can uniquely provide. The scopes described below are recommended to be included as part of the HGPIs for all units.

Table 1. Additional Scope Items included in Proposal

Scope item	Description
Plant Ally	Access to 24 hour x 365 days technical service focusing on issues that affect major turbine components. This will provide OEM level support and feedback related to real time operations. This is vital in monitoring the condition and operation of TC5 with known compressor rotor cracking; TC9, which has a known shorted turn; and all units to predict issues before they become apparent.
Autotune	Monitors unit performance and allows real-time feedback on specific adjustments to control operations based on actual hardware performance and environmental conditions, which will improve operations, availability, and improve or help maintain emissions.
R-0 blade upgrade (compressor)	Improves strength and damage tolerance of blading, which results in reduced inspection requirements while improving availability and reliability.
Generator rotor removal	Included in the project scope due to ▇ experience with shorted turns in the field windings of generators like the Trimble units. We are currently aware of a shorted turn on TC9. The generator rotor removal will allow the field to be rewound or replaced.

The projects in this investment proposal include upgrades to all six units' turbine controls, excitation systems, and LCIs. These scopes are outlined in Table 2.

Table 2. Control Platform Upgrade Scopes

Control Platform Upgrades	Description
▇ Control Upgrades	First of 3-phase approach to upgrade turbine controls, which will maintain support through 2020.
Excitation Upgrades ▇	Exciter upgrade, which will align controls with ▇. This will be required to maintain support into 2020.
LCI (Load Commutator Inverter) Upgrades	This will allow the generator to operate as a synchronous motor to accelerate the gas turbine set according to a specific speed profile, thus providing optimum starting conditions. This software/hardware upgrade is required to maintain support into 2020.

The current schedule for this work by year and unit is as follows:

Table 3. Schedule for HGPI and Controls Platform Upgrades

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024
HGPI	TC6	TC5 TC7	TC9				*TC8		*TC10
Turbine Controls Upgrade	TC6	TC5 TC7	TC9	TC8 TC10					
Excitation Upgrade	TC5 TC6	TC7 TC8	TC9 TC10						
LCI Upgrade	TC5/6	TC7/8	TC9/10						

* The fast start units (TC8 & TC10) are currently scheduled for HGPI in 2022 and 2024, respectively. This is due to a lower level of accumulated factored starts due to related reserve requirements.

- **Competitive Bid Process / Project Cost**

The initial scope of the bid process sought to test the competitive ▮▮▮ frame market as well as combine the combustion turbine maintenance needs at E.W. Brown and Trimble County Generating Stations. After market research and pre-bid screening meetings with potential bidders, four firms where selected to be included in the competition. ▮▮▮ is the OEM for all EW Brown units and provides service to ▮▮▮ machines through a wholly owned subsidiary, ▮▮. ▮ is the OEM for the Trimble County CTs and chose only to bid on services for those machines. ▮▮▮ is a firm long used by LKE for successful steam turbine/generator overhaul labor services. ▮▮▮ teamed with ▮▮▮ ▮▮▮ to bid the Trimble County scopes only. ▮▮▮ was added based on a request from E.W. Brown and their experience with their refurbishment efforts. ▮▮▮ participated with ▮▮▮ as their installation contractor. ▮▮▮ was the only bidder to provide a proposal for all units (▮▮ units and ▮▮ at E.W. Brown and ▮▮ at Trimble). Due to its high pricing for both stations, a decision was made to separate the scopes by station and proceed with negotiations and project authorizations separately. The results of the initial proposals for Trimble County's HGPIs on six ▮▮ are as follows in Table 4.

Table 4. Initial Proposals for HGPIs (2014)

Bidder	Six Trimble ▮ HGPIs ($000) – 2014 Pricing	
███████████████████████████████		
███████████████████████████████		
███████████████████████████████		
███████████████████████████████		

Table 5 summarizes decisions made following review, and clarifications of initial proposals.

Table 5. Summary Following Review and Clarifications of Initial Proposals

Bidder	Short-Listed	Removed	Comments
██			
██			
██			
██			
██			

* *Fallout coverage includes replacement of any failed part within the turbine and combustion sections that are found to be damaged beyond refurbishment or repair during inspection.

- **Best and Final Bid Summary:**

Best and final offerings for HGPIs were received from both ██████████ and ██ on July 1, 2015. The results are summarized in Table 6, showing ██ as the lowest and recommended bidder.

Table 6. Results of Best and Final Offer

Bidder	Six Trimble ▮ ($000) – 2014 Pricing
██	
██	

*With the estimated 3% escalation for HGPI projects within 2016-2024, the total above will result in a contract requirement of $16,240k.

Table 7 summarizes pricing included in ▮ offering for generator rotor removal and three other services that they uniquely provide. These scopes are included within this authorization request. Costs include a 3% escalation rate.

Table 7. ▮ **Additional Scope Offerings**

Included with six HGPI Scopes		Cost ($000) – Includes Escalation for all six units	
▮			
▮			
▮			
▮			

Table 8 summarizes pricing from ▮ for upgrades to control system hardware and software that are required to maintain support for the listed systems through 2020. These upgrades are in the 2016BP as separate projects and are included in this authorization request. Costs include a 3% escalation rate.

Table 8. ▮ **Controls Platform Upgrade Offerings**

Option		Cost ($000) – Includes Escalation	
▮			
▮			
▮			

▮ is recommended for award of the HGPIs, excitation, LCI, and ▮ (shown in Tables 6, 7 and 8) for the following reasons:

- A fifteen percent discount for items outside the HGPI scopes (Tables 7 and 8) were achieved by including them along with the HGPI scope.
- ▮ has agreed to a reduced markup of 20% (lowered from the Master Agreement markup of 25%) for any additional labor, materials and consumables related to company approved changes to the current scope of work.
- Improved warranty terms have also been achieved, with ▮ agreeing to a warranty of 18 months from initial operation or 36 months from delivery, whichever occurs first.
- Pricing will be escalated beyond 2016 based on standard industry indices as agreed upon with a floor of 0.5% and a cap of 2.5%. If inflation greater than 5% is experienced, LG&E and ▮ will split these increases equally.
- Liquidated damages are in place at a daily rate of $15k/day and capped at 10% of the value for each individual HGPI and ancillary scopes.
- ▮ is able to provide additional scope items ▮ and control platform upgrades that are uniquely applicable to ▮ gas turbines.

Economic Analysis and Risks

Budget Comparison and Financial Summary

Table 9. Budget Comparison

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	5,004	9,550	5,177	11,658	31,389
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	5,004	9,550	5,177	11,658	31,389
4. Capital Investment 2016 BP	5,004	9,550	5,177	11,658	31,389
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	5,004	9,550	5,177	11,658	31,389
7. Capital Investment variance to BP (4-1)	(0)	0	-	-	0
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(0)	0	-	-	0

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	270	270	270	1,620	2,430
2. Project O&M 2016 BP	270	270	270	1,620	2,430
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Project Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:

Labor:	$ 60
Contract Labor:	$20,722
Materials:	$ 6,908
Local Engineering:	$ 541
Burdens:	$ 20
Contingency:	$ 3,138
Reimbursements:	($ 0)
Net Capital Expenditure:	$31,389

Table 10. Project and Contract Amounts Requested in This Paper   Arbough

Six (6) Units	2015 Base Bid ($000)	Contract Amount [with 3% escalation] ($000)	Capital ($000)	O&M ($000)
HGPI Base Scope			*24,820	
Other Scope Items:				
				2,430
			1,020	
			685	
			1,165	
Local Engineering			541	
Burdens			20	
Contingency			3,138	
Total Request			**31,389**	**2,430**

*Capital HGPI budget included other scope items:
Capital and O&M request is consistent with 2016 BP.
The detailed split between Capital and O&M by year and Unit is provided within Appendix 3.

A detailed comparison of the individual project expenditures compared to the contract amount is located in Appendix 2. A detailed cost roll-up of all projects can also be found in Appendix 3.

Table 11. Financial Analysis

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	(120)	(37)	(198)	713	915	31,389
Project ROE	-9.4%	-0.7%	-2.4%	7.7%	10.4%	9.8%

Assumptions

- The interval between HGPI is six (6) years, which is consistent with the actual average time needed to accumulate 900 factored between the first and second HGPI. The units will reach their second round of 900 factored starts as follows: TC5 – Spring 2017, TC6 – Fall 2016, TC7 – Fall 2017, TC9 – Fall 2018
- Based on current operating conditions, TC8 and TC10 (fast-start units) will accumulate 900 factored starts in 2022 and 2024, respectively.
- The recommendation assumes the HGPIs and controls projects are completed, and there would be no generation system reserve margin shortfall.

- For the "Do Nothing" alternative, there will be no investment, and the units will not be available to run once they accumulate 900 factored starts. Without these units, there will be a reserve margin shortfall. LG&E is currently purchasing capacity from ███████ ████████████████████████████ Based on this cost, the value of capacity for a Trimble County CT (159 MW) is $771,150/month. The units are assumed to be unavailable until the next overhaul (major inspection) scheduled in the 2016BP.
- For the "Next Best" alternative, the additional projects already in the 2016BP (turbine controls, excitation, and LCI upgrades) would be completed under stand-alone projects and not bundled with the HGPI contract. This would increase the cost of those projects by 15%.
- Three percent per year escalation is included within the contract summary for all years beyond 2016 based on the time period covered within the project.

- **Environmental**

Table 12. New Source Review Evaluation

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.	
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	NO
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	NO
#3	Does the project increase through-put with any of the material handling systems?	NO
#4	Will the project affect the dispatch order or utilization of the unit?	NO
#5	Does the project increase the emissions unit's maximum hourly heat input?	NO
#6	Does the project increase the emissions unit's electrical output (gross MW)?	NO
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	YES Frequency = 6 years, last performed 2010-2013.
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	NO

- **Risks and Issues**

Based on the current operating conditions, TC8 and TC10 (fast-start units) are forecasted to accumulate 900 factored starts in 2022 and 2024, respectively. However, the starts on these units are subject to many factors, which could move their HGPI dates earlier, but likely later and potentially past 2025. These units' factored starts will continue to be monitored, and the plans for investments will be shifted as part of the business planning cycle. If the HGPIs for these units push out past the ▮ contract agreement, then there is potential to re-negotiate to include major inspections for the other units. Major inspections occur after 2400 factored starts, and four of the other units are forecasted to reach that milestone before 2024.

The ▮▮▮▮▮▮▮▮▮▮▮ in this offering is the first of three planned upgrades to the equipment to address obsolescence/non-support in the equipment components. ▮ has advised that the last two phases of the migration/upgrade are not yet available. This issue applies to all of the Trimble gas turbines and the Trimble 2 steam turbine.

Appendix 4 outlines other risks and issues related to the Trimble CTs, but not part of this proposal

- **Conclusions and Recommendation**

It is recommended that the Investment Committee approve the Hot Gas Path Inspections, Exciter (EX2100e), Load Commutator Inverter (LCI) and ███████████████████████ ██ projects for $31,389k. LG&E is also seeking contract approval for all aforementioned projects in the amount of ████████.

Charles Ransdell
Manager Commercial Ops. – Trimble County

Laura S. Mohn
Manager – Engineering & Technical Services

Joseph F. Clements
Dir. Pwr. Generation Commercial Ops.

Jeffrey E. Joyce
General Manager – Trimble County

D. Ralph Bowling
VP Power Production

Paul W. Thompson
SVP Energy Services

Kent W. Blake
Chief Financial Officer

Victor A. Staffieri
Chairman CEO and President

Appendix 1: List of TILs to be addressed as part of HGPI   Arbough

TIL #	Title	Description
1132-2R1	Variable Inlet Guide Vanes - Spring and Thrust Washers	Inspection only at IGV washers
1280-2R1	Inspection of F-Class Turbine Wheel Retaining Ring Tabs	Inspection of turbine wheel at retaining tab that holds bucket lock wire
1397-1R2	DLN 2.0 and DLN 2.6 Combustion Forward Casing Inspections	Inspect steam injection annulus on combustion casing
1509-R3	F-Class Front End (R0/R1) Compressor Inspections	Inspect compressor blades
1540-2	F-Class Turbine Rotor Inspection and Maintenance Recommendations	Inspection of the cooling air slot on turbine wheel that feeds cooling air to bucket
1584-R1	████ Turbine Shell Inlet Bleed Heat (IBH) Extraction Pipe Weld Crack	Inspection of pipe that takes off air from compressor discharge casing to inlet bleed heat
1585	Proper Use and Care of Flexible Metal Hoses	Inspect the flexible hoses on the machine, mainly the fuel gas flex hoses
1606	████ End Cover Purge Air Diffusion Pipe Weld Inspection	Inspection of purge air connection on fuel nozzle for cracks
1638-R1	F-Class R0/R1 Platform Ultrasonic Testing	Inspection of compressor blades at root of blade
1724-R1	Inspection and Cleaning of Quaternary Fuel Annulus	This annulus is prone to contamination from failing brazing used to make the fuel nozzle
1742	F-Class Turbine Wheel 1 Balance Weight Groove Inspection	Correct staking procedure for balance weights on turbine wheels
1858	████ 2nd Stage Bucket Inspection Recommendations	The second stage bucket is prone to bucket shroud lifting
1907	Rotor Forward Shaft Dovetail Crack	The stub shaft that holds the R0 blades are developing cracks

Appendix 2: Project and Contract Approval Comparison ($000's)   Arbough

Trimble 2016 BP	2016	2017	2018	2019	2020	2021	2022	2023	2024	Total
Unit	6	5&7	9				8		10	

Notes:

- Difference between project and contract amounts is for other work related to the HGPI or controls upgrade projects, and not part of ▮▮▮ scope.

- Project amounts include 10% contingency for unknowns related to part conditions and unforeseen expenditures.

- ▮▮▮▮ (9%) of contract contingency is reserved for potential change orders and is not included in the above contract amount.

Appendix 3: See Attached Excel Spreadsheet

Appendix 4: Other Risks and Issues Related to the Trimble CTs, but not part of the Arbough proposal

Cracking on the 12th through 17th stages of compressor rotor

TIL 1972 covers potential crack development on the 12th through 17th stage compressor rotor wheels due to the thermal stresses experienced by these wheels during normal operation of the turbine. These cracks are more susceptible on wheels with flat slot bottoms and we have two units identified to be on that list. The units are TC5 and TC6, commissioned in 2002 and most likely manufactured in the end of 2000 and beginning of 2001 time frame. If cracks are found to the extent that makes the unit inoperable, we are exposed to a $13 million variance (price for a refurbished rotor) per unit, or an extended outage until the existing turbine rotor is removed, de-stacked, repaired, and re-installed in the unit. We do not have an estimate for the rotor removal and repair because we will be at the mercy of compressor wheel availability and market forces driving metal prices at that point.

Presently, we know cracking exists on the TC5 compressor from a borescope inspection completed in September 2015.   We have notified ▮ of this condition and supplied data. Presently, we believe the recommendation for this unit will be to monitor the unit.   Repairs may / will be required in the future.

Shorted turns on generator rotors

Through monitoring of vibration data and some testing, it has been determined that TC9 has shorted turns in the field winding. Trimble 9 is experiencing high vibrations during a critical speed during its startup process. After reviewing our unit specific data with ▮ they agree we have a shorted turns. ▮ has told us issue is caused by a combination of:

- Time spent on turning gear
- Cycling of machine
- Thermal forces associated with cycling of machine
- Breaker misoperations / malfunctions that stress the machine

▮ has a fleet of over 800 machines that are like the Trimble CT generators with over 60 rewinds in their field.   They indicated an 8% probability of shorted turns occurring in any fleet of similar machines. Ultimately, this field may need to be rewound with an estimated cost of $820,000 per machine, plus labor and services estimated at $300,000 per unit.   Other options include purchase of a spare field and ▮ field exchange program. We plan additional testing on Trimble 9, a more detailed review of vibration trends on the entire fleet, and the addition of flux probes on each unit.

Given cycling of the machines and turning gear time are the primary causes of shorted turns, the potential exist for shorted field turns for the remainder of the Trimble Co CT fleet.

Trimble Combustion Turbine Unit	TC6	TC5	TC7	TC9				TC8		TC10	Total
Year	2016	2017	2017	2018	2019	2020	2021	2022	2023	2024	
HGPI	2,440,077.00	2,513,279.31	2,513,279.31	2,588,677.69				3,000,986.94		3,183,747.04	16,240,047.29
HGPI Scope Enhancements											
Generator Rotor removal	243,688.00	250,998.64	250,998.64	258,528.60				290,976.22		308,696.67	1,603,886.76
Autotune	276,375.00	284,666.25	284,666.25	293,206.24				330,006.20		350,103.58	1,819,023.52
Generator lift oil hoses and H2 seal rings	14,164.08	14,164.08	14,164.08	14,164.08				14,164.08		14,164.08	84,984.48
Enhanced R-0	367,533.33	378,559.33	412,217.33	424,583.85				477,872.86		506,975.32	**2,567,742.02**
Plant Ally O&M	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	2,700,000.00
Plant Ally Capital	91,726.00										91,726.00
Total HGPI and upgrades	3,703,563.41	3,711,667.61	3,745,325.61	3,849,160.46				4,384,006.30	4,492,837.49	4,633,686.69	25,107,410.08
Project Scope items in addition to HGPI											
EX2100e	249,974.00	141,821.00	146,075.63	146,075.63	150,457.90	150,457.90					984,862.06
LCI	232,311.00	217,401.07	223,923.10								673,635.17
Mark VI Upgrades	163,603.00	168,511.09	168,511.09	173,566.42	178,773.42	178,773.42					1,031,738.43
Software acceptance test	8,688.00										8,688.00
											2,698,923.66
Total Capital	4,088,139.41	3,969,400.77	4,013,835.43	3,898,802.51	329,231.31	329,231.31		4,114,006.30		4,363,686.69	**25,106,333.74**
Total O&M Cost	270,000.00	270,000.00		270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	270,000.00	**2,430,000.00**
Total Contract Spend HGPI along with requested scope items											
Contingency (10%)											
Sanction Request											

Investment Proposal for Investment Committee Meeting on: <u>November 28, 2018</u>

Project Name: <u>TC DCS Upgrades</u>

Total Expenditures<u>: $3,748k gross ($2,880k net) (Including $341k gross ($262k net of contingency)</u>

Project Number(s): <u>137587 – TC1 DCS Upgrade, 137585LGE – TC2 DCS Upgrade, 140014LGE – TC CT DCS Upgrade</u>

Business Unit/Line of Business: <u>Power Generation</u>

Prepared/Presented By: <u>Rick Boone / Tommy Della Rocco</u>

Executive Summary

This project will help ensure Cyber Security Compliance of our Distributive Control Systems (DCS) at Trimble County in accordance with NERC CIP-007-3 (*NERC Critical Infrastructure Protection*).

The ▮▮▮▮▮▮▮▮▮DCS System Operator Station HMIs (Human Machine Interface) run on the ▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮▮ will be discontinuing support of ▮▮▮▮▮▮ on January 14, 2020. This means that ▮▮▮▮▮▮will no longer be providing Security Patches for ▮▮▮▮▮▮ The ▮▮▮▮▮▮ Control System network relies on ▮▮▮▮switches and routers for all network communication. The ▮▮▮▮ products currently in service at Trimble are becoming obsolete. ▮▮▮▮ will be discontinuing support on these products October 31, 2019. These two issues require that every Workstation (HMI) and all ▮▮▮ Switches/Routers be replaced and loaded with latest software configurations to keep Trimble County compliant with NERC CIP-007-3.

Since our initial install of the ▮▮▮▮▮▮▮▮ DCS in 2007, we have added several controllers and other hardware devices to our DCS network to accommodate new projects. These projects include the TC1 Pulse Jet Fabric Filter (PJFF), Coal Combustion Residual Transport (CCRT), Process Water System (PWS) and TC2 Turbine Controls, etc. These additions have added to the network loading and communication traffic on our DCS System. To help ease the network loading, we will be upgrading the Processor Modules in all of the ▮▮▮▮▮▮Controllers. This will also allow us to bring our DCS up to the latest ▮▮▮▮▮▮▮▮ Software version.

One other hardware item that is becoming obsolete in our ▮▮▮▮▮▮▮▮ Controllers are the DC Power Supplies. We will be replacing critical DC Power Supplies during this Evergreen Project and use our existing ▮▮▮▮▮▮ Service Agreement to replace the remaining DC Power Supplies when necessary.

This proposal covers the entire DCS Control System at Trimble County. The total cost of the combined projects is $3,748k gross, and a total of $4,385k gross was included in the 2018BP across the three projects as follows:

- Project Number 137587: covers the Trimble County Unit 1 DCS Control System Network.
- Project Number 137585LGE: covers the Trimble County Unit 2, Common and the Trainer DCS Control System Network.
- Project Number 140014LGE: covers the Trimble County Combustion Turbine DCS Control System Network.

These projects are fully funded in the proposed 2019 Business Plan.

Background

The current DCS Control Systems are fully functional and operate on the ███████████████. These systems are fully supported by ████████. However, the requirements of NERC-CIP 007, ████████ discontinuing support of the network Routers and Switches, and ████████ discontinuing support for ████████ require us to upgrade the Control System as described in this proposal. The current replacement for the ████████████ platform is ████████.

The HMI hardware currently in place at Trimble County will be over 7 years old when this project begins and they are not sized to run the new software (████████). Therefore, this hardware must be replaced with ██████ validated equipment designed to operate with ████████ software.

████████ is currently planning to provide support for ████████ through October 2025. We anticipate similar projects in 2025 based upon ████████ end of support schedule.

The benefits we will obtain upon completion of this project are:
- Maintain NERC-CIP-007-3 compliance through 2025.
- Control System Network performance improvements will be gained by upgrading the ████████ Controller processor modules.
- Upgrading our control system software from ████████████████████ to the latest ████████████████████, will give us more flexibility with alarm management on our control system. ████████████████████ also offers additional troubleshooting tools to diagnose problems as they occur on our system. This will decrease downtime if problems on our control system network occur.

- **Alternatives Considered**

  1. Recommendation: (Upgrade Existing System)   NPVRR: ($000s)__$3,109____
  2. Alternative #1: (Do Nothing)   NPVRR: ($000s)__$5,963____
  3. Alternative #2: (Control System Change out) NPVRR: ($000s)__$11,394 +_

The Recommendation is to make the necessary upgrades to our existing ████████ Control System. It is the most cost effective and offers the least amount of risk to the Trimble County Control System.

Alternative #1: (Do Nothing) exposes us to potential fines due to non-compliance with NERC CIP-007-3. The ██████████████████████, used on the HMIs (Human-Machine Interface Stations) on our Control System would no longer receive updated Security Patches from ████████ This would make our Control Systems vulnerable to software viruses and malware that could potentially force extended Unit Outages.

Alternative #2: (Complete Control System Change Out) a complete change out of all system control and configurations would be risky and likely result in the same proprietary structure at a higher cost than upgrading our existing ████████controls. It would also require extended outages to install and thoroughly checkout a new control system, not to mention the months of Engineering and planning involved to undertake this task. The NPVRR amount for Alternative #2 was based off our initial Control System change out of the TC Unit 1 (2009) and Common (2007) Control Systems with a 3% inflation rate over 10 years ($11,394k). This estimate does not include upgrading the DCS on Trimble County Unit 2 which would be an additional significant impact.

Project Description

- **Project Scope and Timeline**

This project will replace all necessary hardware and software required to meet the requirements of NERC CIP-007-3.

Since we have a Multi-network design in our DCS Systems at Trimble, the hardware and software installation for this project will be completed in five stages throughout 2019. Those stages are listed in chronological order below:

1. Trimble Unit 2 DCS Network and Core Network (3/11/2019 – 4/14/2019)
2. Trimble Combustion Turbine DCS Network (6/10/2019 – 6/14/2019)
3. Trimble Trainer System DCS Network (6/10/2019 – 6/14/2019)
4. Trimble Common DCS Network (10/14/2019 – 11/8/2019)
5. Trimble Unit 1 DCS Network (10/14/2019 – 11/8/2019)

Trimble County Major Milestones for Stage 1 (Trimble Unit 2 DCS Network and Core Network, 3/11/2019 – 4/14/2019):

November, 2018	Proposal to Investment Committee
January, 2019	Material order placement
February, 2019	Factory Acceptance Test for TC Unit 2 and Core Networks
March, 2019	Hardware and Software installation *(TC2 Spring Outage)*

Trimble County Major Milestones for Stages 2 & 3 (Trimble Combustion Turbine DCS
Network and the Trimble Trainer System DCS Network, 6/10/2019 – 6/14/2019):

November, 2018	Proposal to Investment Committee
March, 2019	Material order placement
May, 2019	Factory Acceptance Test for TC Combustion Turbine and Trainer System Networks
June, 2019	Hardware and Software installation

Trimble County Major Milestones for Stages 4 & 5 (Trimble Common DCS Network and the
Trimble Unit 1 DCS Network, 10/14/2019 – 11/8/2019):

November, 2018	Proposal to Investment Committee
May, 2019	Material order placement
September, 2019	Factory Acceptance Test for TC Common and TC Unit 1 Networks
October, 2019	Hardware and Software installation *(TC1 Fall Outage)*

The date ranges listed above for Stage 1 and Stage 4 correlate to the outage schedules for
Trimble Units 1 and 2. Each of these Stages will take 2 weeks to complete. Stage 2 will only
require 2-3 days to complete.

- **Project Cost**

The total cost of the projects in 2019 will be $3,748k gross. This includes all labor, materials and
engineering required to complete the full scope of the work. A 10% contingency has been
included for unexpected issues that may arise during the upgrade process.

Economic Analysis and Risks

- **Bid Summary**

A formal bid process was not conducted for control system components, upgrades and services.
The control systems at Trimble County are proprietary to ▇▇▇▇▇▇ which makes competitively
bidding control hardware, software and services extremely difficult, unless a complete change
out of all system control and configurations are made. A complete change out of all system
control and configurations would be risky and likely result in the same proprietary structure at a
higher cost than upgrading our existing Emerson controls.

LG&E and KU entered a contract with ▇▇▇▇▇▇ in 2015 to provide control system components,
upgrades, and services for Cane Run, Ghent and Trimble County generating stations through
2020. These projects are included in the aforementioned contract.

There are two "Budget Comparison and Financial Summary" charts included in this
document. The first chart is for the Steam Side DCS Networks which are co-owned with
IMEA and IMPA. The second chart is for the Combustion Turbine DCS Network which is
not co-owned.

- **Budget Comparison and Financial Summary for Co-owned Portion. (Steam Side DCS Networks: TC1, TC2, Common and Trainer)**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed		2,344			2,344
2. Cost of Removal Proposed		261			261
3. Total Capital and Removal Proposed (1+2)	-	2,605	-	-	2,605
4. Capital Investment 2018 BP		2,751			2,751
5. Cost of Removal 2018 BP		306			306
6. Total Capital and Removal 2018 BP (4+5)	-	3,057	-	-	3,057
7. Capital Investment variance to BP (4-1)	-	407	-	-	407
8. Cost of Removal variance to BP (5-2)	-	45	-	-	45
9. Total Capital and Removal variance to BP (6-3)	-	452	-	-	452

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 52
Contract Labor:	$2,436
Materials:	$ 430
Local Engineering:	$ 62
Burdens:	$ 177
Contingency:	$ 316
Reimbursements:	($ 868)
Net Capital Expenditure:	$2,605

- **Budget Comparison and Financial Summary for the CT DCS Network**   Arbough

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed		248			248
2. Cost of Removal Proposed		27			27
3. Total Capital and Removal Proposed (1+2)	-	275	-	-	275
4. Capital Investment 2018 BP		279			279
5. Cost of Removal 2018 BP		31			31
6. Total Capital and Removal 2018 BP (4+5)	-	310	-	-	310
7. Capital Investment variance to BP (4-1)	-	31	-	-	31
8. Cost of Removal variance to BP (5-2)	-	4	-	-	4
9. Total Capital and Removal variance to BP (6-3)	-	35	-	-	35

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed					-
2. Project O&M 2018 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 8
Contract Labor:	$ 187
Materials:	$ 33
Local Engineering:	$ 5
Burdens:	$ 17
Contingency:	$ 25
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 275

- **Assumptions**

The CEM assumed a 5% risk of a cyber-attack or security breach that could lead to a one week unit outage, if we choose to "DO NOTHING' the first year. If we are unable to install the latest ▉▉▉▉ Security Patches, the risk and outage times increase as more time passes. This assumption does not consider other potential equipment damage or risk to personnel safety that could be caused by losing control of the DCS System. Also, certain components in our control system will become obsolete (processor modules, power supplies, etc.). This could increase outage rates and down time while we try to acquire adequate replacements for failed components.

By choosing the recommendation to secure control system components, upgrades and technical services to support the ████████ proprietary control system, we will be able to maintain NERC-CIP-007-3 compliance through 2025, as well as, improve control system performance, maintain a robust resilience from cyber-attacks and ease network loading as described in the Executive Summary.

- **Environmental**

New Source Review Evaluation questions 1-8 must all be completed on all investment proposals.		
#1	Does the project include any new equipment or component with air emissions or result in air emissions not previously emitted?	No
#2	Does the project involve equipment that is part of a regulated air emission unit? a. Is change a like-kind or functionally equivalent replacement?	No
#3	Does the project increase through-put with any of the material handling systems?	No
#4	Will the project affect the dispatch order or utilization of the unit?	No
#5	Does the project increase the emissions unit's maximum hourly heat input?	No
#6	Does the project increase the emissions unit's electrical output (gross MW)?	No
#7	Has the equipment or component in question been repaired or replaced in the past at this unit? a. Provide frequency or when equipment or component in question was last repaired or replaced.	No
#8	Have there been forced outages or unit derates in the past 5 years due to this component of the equipment? a. Provide GADS data of derates and forced outage for each of the last 5 years applicable to the project.	No

There are no environmental implications associated with this project.

- **Risks**

The risk of not completing this project is the Control System at Trimble County would become vulnerable to cyber-attacks that could result in loss of generation and equipment damage. Also, Trimble County would no longer be compliant with NERC CIP-007-3.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Trimble County DCS Upgrade projects for $3,748k gross ($2,880k net) to comply with NERC CIP007-3 and decrease the risk of cyber-attack.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal for Investment Committee Meeting on: December 20, 2017

Project Name: Viley Road Distribution Substation Expansion

Total Approved Expenditures: $7,291k (Approved on 1/3/2017)

Total Revised Expenditures: $8,049k, with an additional $758k requested

Project Number(s): Distribution Substations 148720, Distribution Lines 152820, Transmission Lines 137751

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tony Durbin

Reason for Revision
The original investment proposal (attached) was approved by the Investment Committee on January 3, 2017 for $7,291k. An additional $758k is necessary to complete the substation portion of the project. After the project was opened and contracts initiated, it was determined that additional funding was needed in the following areas to complete the substation:

Category	Original Estimate Direct Cost ($000s)	Current Actuals Plus Additional Estimated Cost ($000s)	Requested Additional Funding ($000s)
Site Construction	$ 1,000	$1,385	$ 385
Capital Equipment	$ 1,640	$1,930	$ 290
Design Engineering	$ 370	$ 453	$ 83
		Total (Burdened)	$ 758

Site Construction. The "Below Grade" site construction bid package was issued to four experienced substation contractors with whom the substation group has previously done business. Three contractors submitted a bid. The original estimate for site work (both below grade and above grade) was $1,000k, but the actual bid for below grade work alone was $989k. Estimates for yet-to-be-completed above grade work bring the total site construction estimate to $1,385k.

Capital Equipment. Some of the capital equipment on this project was underestimated Although original project estimate. These increases are partially offset by lower than estimated costs on breakers and transformers.

	Original Estimate	*Actual Cost*	*Difference*
Steel Package	$300k	$514k	$214k
Control House	$300k	$555k	$255k

Design Engineering. An engineering contract partner was chosen to complete the substation design. Initial estimates included in the original Investment Proposal were lower than the actual costs to complete the design.

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.5%	6.32%	
Capital Breakdown:			
Labor:	$ 208	$ 308	
Contract Labor:	$2,693	$3,208	See explanations above
Materials:	$2,591	$2,879	See explanations above
Local Engineering:	$ 603	$ 653	
Burdens:	$ 533	$ 548	
Contingency:	$ 663	$ 453	
Reimbursements:	($ 0)	($ 0)	
Net Capital Expenditure:	$7,291	$8,049	
NPVRR:	$8,423	$9,456	

Financial Detail by Year - Capital ($000s)	2017	2018	Post 2018	Total
1. Capital Investment Proposed	3,848	3,867	-	7,715
2. Cost of Removal Proposed	35	299	-	334
3. Total Capital and Removal Proposed (1+2)	3,883	4,166	-	8,049
4. Capital Investment 2018 BP	2,772	4,109	-	6,881
5. Cost of Removal 2018 BP	35	165	-	200
6. Total Capital and Removal 2018 BP (4+5)	2,807	4,274	-	7,081
7. Capital Investment variance to BP (4-1)	(1,076)	242	-	(834)
8. Cost of Removal variance to BP (5-2)	-	(134)	-	(134)
9. Total Capital and Removal variance to BP (6-3)	(1,076)	108	-	(968)

Financial Detail by Year - O&M ($000s)	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-
3. Total Project O&M Variance to BP (2-1)	-	-	-	-

The 2018 BP includes $4,274k in 2018 for this project. The incremental $1,076k for 2017 was approved through the Corporate RAC process in October and includes some minor burden changes offsetting the total amount of $1,100k. The lower cost in 2018 is due to a $342k shift from 2017 (for the total incremental requested on the approved amount of $758k), partially offset by a shift in the circuit work spending from 2017 to 2018.

With this requested increase, this recommended scope of work remains the least cost alternative to address the issues presented as part of this project. The original estimates for the site construction and capital equipment in the alternative in the original proposal were under estimated as well as in this option.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the revised Viley Road Distribution Substation Expansion project for $8,049k, an increase of $758k, to provide adequate distribution substation capacity for existing and future loads in Lexington, KY, and remove the Viley Road and Trafton Substations from EDO's N1DT list.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Date	
Chief Financial Officer		

Paul W. Thompson	Date	
President and Chief Operating Officer		

Attachment A

Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: Viley Road Distribution Substation Expansion

Total Expenditures: $7,291k (includes $663k of contingency)

Project Number(s): Distribution Substations 148720, Distribution Lines 152820, Transmission Lines 137751

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Cline/Beth McFarland

Executive Summary

Electric Distribution Operations (EDO) Electric Engineering and Planning (EEP) seeks funding authority for distribution substation, distribution circuit, and transmission line improvements in and near the Viley Road substation. The Viley Road substation is located on Alexandria Drive on the northwest side of Lexington, KY and serves approximately 3,874 industrial, commercial, and residential customers. The existing 39.2 MVA distribution transformer is forecasted to reach 123% of its top nameplate capacity during the winter of 2016-2017 (assumes average temperature conditions), and 130% during the winter of 2018-2019. The purpose of this Investment Proposal is to request substation capacity improvements in the form of a second 37.3 MVA transformer in the Viley Road substation (plus associated transmission and distribution circuit improvements) in order to reduce the load on the existing Viley Road substation transformer. In addition, the proposed improvements remove the Viley Road and Trafton Ave 12 kV transformers from the Company's "Distribution Substation Transformer Contingency Program" (N1DT) list, while reducing the load on the most heavily loaded distribution circuit. This project is scheduled to begin in January 2017 with completion in December 2018.

This project is included in EDO's 2017 Business Plan (BP) for $6,196k. The budget shortfall in 2018 will be addressed through reallocation from approved funding sources which will be presented for approval through the Corporate RAC process.

Background

The Viley Road substation contains a single 39.2 MVA, 138-12 kV transformer. The measured peak transformer load was 50.35 MVA (128% of its top nameplate) during the winter of 2014-2015 and the transformer load is currently forecasted (under average temperature conditions) to reach 123% (winter 2016-2017) and 130% (winter 2018-2019). Distribution Planning guidelines allow up to 120% of the top nameplate rating during forecasted normal winter conditions. The installation of a new 37.3 MVA substation transformer and associated improvements in the Viley Road substation are proposed to provide load relief for the Viley Road substation transformer.

In addition, the Viley Road substation is on EDO's N1DT list. This list identifies substation transformers, which in the event of a transformer failure during high load periods, cannot be completely restored by switching to surrounding substations and circuits. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer, which in the case of the Viley Road substation, could take up to 36 hours. While not the primary justification for this project, removing the substation transformer from the N1DT list is a recommended secondary goal for this project because: 1) the largest mobile transformer is a 30 MVA transformer which is not large enough to meet capacity needs at this substation, and 2) it is difficult to schedule planned outages to perform maintenance even during off-peak periods. In addition, the completion of this project as proposed would also remove the Trafton Ave 12 kV transformer from the N1DT list.

- **Alternatives Considered**

1. Recommended Option: NPVRR ($000): $8,423
   EEP's recommended option is to install a new standard 37.3 MVA transformer, steel, and breakers in the Viley Road substation (plus associated transmission and distribution line improvements). This option is expected to eliminate the forecasted Viley Road transformer overload, remove the Viley Road and Trafton Ave 12 kV transformers from EDO's N1DT list, and reduce the load on the most heavily loaded Viley Road circuit. The estimated cost of this option is $7,291k.

2. Do Nothing Option: NPVRR ($000): N/A
   KU has an obligation to serve all customers and associated load. The "do nothing" option is not considered an acceptable option because it exceeds Distribution Planning's operating limits for distribution substation power transformers, and this practice reduces the life of the substation transformer and elevates the risk of failure of a high value, critical asset.

3. Alternative 1:   NPVRR: ($000s) $9,362
   This option considers the installation of a new 37.3 MVA transformer, steel, and breakers on a new green field site (plus associated transmission and distribution line improvements). This option meets capacity needs and accomplishes the same level of N1DT service as the recommended option, but is expected to cost more than the recommended option because of property, site preparation and transmission line extension costs. The estimated cost of this alternative is $8,011k.

Project Description
- **Project Scope**
  - Substation project #148720: estimated cost $4,900k ($2,200k-2017; $2,700k-2018).
    - Install a new 37.3 MVA, 138-12 kV transformer, breakers, steel, control house, and associated equipment in the Viley Road substation; install the mobile transformer to serve the substation load during construction.
  - Distribution project #152820: estimated cost $1,644k ($600k-2017; $1,044k-2018).
    - Install approximately 13,700' of 795 AAC conductor for two new distribution exit circuits and relocate other substation exit circuits to the new substation transformer;

perform other temporary work as necessary to accommodate the use of the mobile Although transformer during construction.

- Transmission project #137751: estimated cost $747k ($233k-2017; $514k-2018).
  - Install poles and conductor as needed to route the 138 kV transmission line into the Viley Road substation; perform other temporary work as necessary to accommodate the use of the mobile transformer during construction.
  - A Network Integration Transmission Service (NITS) request was submitted to TranServ International on September 30, 2016 for a new delivery point. Load will be transferred from the existing Viley Road transmission delivery point to the new delivery point, but is not expected to alter the existing transmission improvement plans in the area.

- **Project Timeline**
  - January, 2017: Open projects.
  - February-March, 2017: Perform substation and transmission engineering design related tasks; order major equipment.
  - April-June, 2017: Perform distribution engineering design related tasks for planned 2017 work; order materials.
  - July-December, 2017: Complete distribution conductor improvements for planned 2017 work; receive major substation and transmission equipment.
  - January-April, 2018: Perform substation site preparation and foundation work; perform distribution engineering design related tasks for planned 2018 work; order materials.
  - May-August, 2018: Progress on transmission foundations and pole installation; progress on distribution conductor improvements for planned 2018 work.
  - September-November, 2018: Install mobile transformer, substation structures and equipment; progress on distribution conductor improvements.
  - December, 2018: Complete remainder of substation, transmission, and distribution improvements; commission substation.

- **Project Cost**
  The total estimated cost of the project is $7,291k. The substation and transmission line cost estimates are consistent with the "Conceptual Level 1" engineering design designation. The distribution cost estimate is consistent with the 'Preliminary" engineering design designation and is based on field experience from similar projects. There is an estimated 10% of contingency ($663k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - The substation transformer and steel package as well as transmission poles will be bid using established Supply Chain procedures.
  - For other requirements, Substation Construction and Maintenance (SC&M), Distribution Operations, and Transmission Lines will use existing material and labor contracts and follow established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,998	3,959			6,957
2. Cost of Removal Proposed	35	299			334
3. Total Capital and Removal Proposed (1+2)	3,033	4,258	-	-	7,291
4. Capital Investment 2017 BP	3,061	2,867			5,928
5. Cost of Removal 2017 BP	120	148			268
6. Total Capital and Removal 2017 BP (4+5)	3,181	3,015	-	-	6,196
7. Capital Investment variance to BP (4-1)	63	(1,092)	-	-	(1,029)
8. Cost of Removal variance to BP (5-2)	85	(151)	-	-	(66)
9. Total Capital and Removal variance to BP (6-3)	148	(1,243)	-	-	(1,095)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was identified and funded in EDO's 2017 Business Plan at the following levels: Substation project #148720 ($2,210k-2017; $2,000k-2018); Distribution project #152820 ($600k-2017; $600k-2018); Transmission project #137751 ($371k-2017; $415k-2018). The $1,243k budget shortfall in 2018 will be addressed in the 2018 Business Plan.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 208
Contract Labor:	$ 2,693
Materials:	$ 2,591
Local Engineering:	$ 603
Burdens:	$ 305
Contingency:	$ 663
Transportation:	$ 228
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 7,291

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution improvements are consistent with similar past projects.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**
  - The cost of the distribution portion of the project could escalate because a detailed engineering design was not conducted due to resource limitations and time constraints prior to the preparation of the cost estimates. Costs are based on similar completed work for other projects of similar scope and size.
  - Failure to complete this project in a reasonable time frame could negatively impact the company's ability to serve the growing loads in the area. Insufficient infrastructure could result in outages and/or failure of the existing substation transformer.

Conclusions and Recommendation

EDO EEP recommends that the Investment Committee approve the Viley Road Distribution Substation Expansion project for $7,291k to provide adequate distribution substation capacity for existing and future loads in Lexington, KY, and remove the Viley Road and Trafton Substations from EDO's N1DT list.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: Viley Road Distribution Substation Expansion

Total Expenditures: $7,291k (includes $663k of contingency)

Project Number(s): Distribution Substations 148720, Distribution Lines 152820, Transmission Lines 137751

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Cline/Beth McFarland

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  - A Network Integration Transmission Service (NITS) request was submitted to TranServ International on September 30, 2016 for a new delivery point. Load will be transferred from the existing Viley Road transmission delivery point to the new delivery point, but is not expected to alter the existing transmission improvement plans in the area.

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  - September-November, 2018: Install mobile transformer, substation structures and equipment; progress on distribution conductor improvements.
  - December, 2018: Complete remainder of substation, transmission, and distribution improvements; commission substation.

- **Project Cost**
  The total estimated cost of the project is $7,291k. The substation and transmission line cost estimates are consistent with the "Conceptual Level 1" engineering design designation. The distribution cost estimate is consistent with the 'Preliminary" engineering design designation and is based on field experience from similar projects. There is an estimated 10% of contingency ($663k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - The substation transformer and steel package as well as transmission poles will be bid using established Supply Chain procedures.
  - For other requirements, Substation Construction and Maintenance (SC&M), Distribution Operations, and Transmission Lines will use existing material and labor contracts and follow established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,998	3,959			6,957
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4. Capital Investment 2017 BP	3,061	2,867			5,928
5. Cost of Removal 2017 BP	120	148			268
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7. Capital Investment variance to BP (4-1)	63	(1,092)	-	-	(1,029)
8. Cost of Removal variance to BP (5-2)	85	(151)	-	-	(66)
9. Total Capital and Removal variance to BP (6-3)	148	(1,243)	-	-	(1,095)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed					-
2. Project O&M 2017 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

This project was identified and funded in EDO's 2017 Business Plan at the following levels: Substation project #148720 ($2,210k-2017; $2,000k-2018); Distribution project #152820 ($600k-2017; $600k-2018); Transmission project #137751 ($371k-2017; $415k-2018). The $1,243k budget shortfall in 2018 will be addressed in the 2018 Business Plan.

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:

Labor:	$ 208
Contract Labor:	$ 2,693
Materials:	$ 2,591
Local Engineering:	$ 603
Burdens:	$ 305
Contingency:	$ 663
Transportation:	$ 228
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 7,291

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution improvements are consistent with similar past projects.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**
  - The cost of the distribution portion of the project could escalate because a detailed engineering design was not conducted due to resource limitations and time constraints prior to the preparation of the cost estimates. Costs are based on similar completed work for other projects of similar scope and size.
  - Failure to complete this project in a reasonable time frame could negatively impact the company's ability to serve the growing loads in the area. Insufficient infrastructure could result in outages and/or failure of the existing substation transformer.

Conclusions and Recommendation

EDO EEP recommends that the Investment Committee approve the Viley Road Distribution Substation Expansion project for $7,291k to provide adequate distribution substation capacity for existing and future loads in Lexington, KY, and remove the Viley Road and Trafton Substations from EDO's N1DT list.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Investment Proposal   **Arbough**

Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Transmission Relocation for Expansion of Waste Management's Outer Loop
Recycling and Disposal Facility (R.D.F.)

Total Project Expenditures: $13.4Mk gross, $0.5M net   (Includes $1.2M contingency)
Total Estimated Contract Value (Electric Transmission Relocation): $9.0M gross, $0 net
Total Estimated Contract Value (Gas Transmission Relocation): $4.4M gross, $0.5M net

Project Number(s): 146709 (Electric Transmission) and 148081 (Gas Transmission)

Business Unit/Line of Business: Electric Transmission/Gas Distribution

Prepared By: Dave Harmeling and John Doll

Presented By: Keith Steinmetz/Tom Reith

Executive Summary

Approval is requested from the Investment Committee to proceed with a $13.4M relocation
project to be funded by Waste Management, Inc., along with approval of the associated Electric
Transmission Line Relocation Contract and the Gas Transmision Line Relocation Contract
which specify the scope of work, funding and timing for the project. During December 2013,
Waste Management contributed $250k to Louisville Gas and Electric (LG&E) for LG&E to
prepare estimates for the relocation of approximately 6,000 feet of an electric transmission line
and a natural gas pipeline. Following completion of the study and based on the estimates
provided, Waste Management expressed an interest in committing to the relocation of both lines
with construction to occur in 2017 and 2018. Upon approval of the projects, Waste Management
signed applications for relocation of the electric and gas transmission lines on an "actual cost"
basis. The application terms include Waste Management making periodic contributions
throughout the project and receiving either an invoice or a partial refund at the conclusion of the
project depending on whether the actual cost exceeds or falls short of the estimate.

The gross cost of this project is estimated to be ████████ Waste Management will pay ████
████ of the costs through periodic contributions. Waste Management will not pay ████
for the difference in the diameter of the gas pipe being relocated and that of the pipe that LG&E
may elect to use instead. The contributions will be taxable when received. Although Waste
Management will also not reimburse LG&E for the amount of the taxes paid, LG&E will recover
the entire amount of the tax payments through future tax savings through depreciation during the
following 20 years. The net present value of the difference in timing between payment and
recovery of the taxes is ($2.1M).

The project is included in the 2016 BP for net $0 ($10.9M gross) and the proposed 2017 BP through net $0 ($9.1M gross). As the scope, timing and certainty of work has evolved, the estimates have been further refined. The unreimbursed portion of the project will be addressed by the Corporate RAC and in the 2018 BP. All gross and net amounts included in the electric and gas contract agreements are based on the estimates for the project.

Background

LG&E was approached by Waste Management during mid-2013 to provide an estimate to relocate approximately 6,000 feet of both the electric and gas transmission lines that currently bisect their recycling and disposal facility commonly referred to as the Outer Loop landfill. This would provide Waste Management several additional years during which the facility could remain in active operation and accept waste deliveries. The timing of Waste Management's request is due partly to their current engagement in a project to expand the footprint of their fillable area. The contract specifies that LG&E will complete the project on or before March 1, 2019. During December 2013, Waste Management contributed $250k to fund the study necessary to produce the estimates for the relocation of the 138KV Appliance Park – Ashbottom electric transmission line and the 20" Preston-Penile natural gas transmission pipeline. Concurrent to Waste Management's design efforts on their disposal facility expansion and in cooperation with their contracted consulting engineer, relocation plans were developed and estimates were prepared for these company facilities. Gas management is considering increasing the size of this pipeline from 20" to 24" and assuming that 24" pipe is installed, Waste Management would be paying what it would cost to relocate a 20" pipeline.
Through August 2016, LG&E has spent approximately $74k of the $250k contribution for the study. Both the study costs and contribution will ultimately be transferred to this project, and any of the unspent contribution will be applied to the cost of the construction.

Following is an aerial view of the relocation where the red line represents the existing route and the green line the proposed.
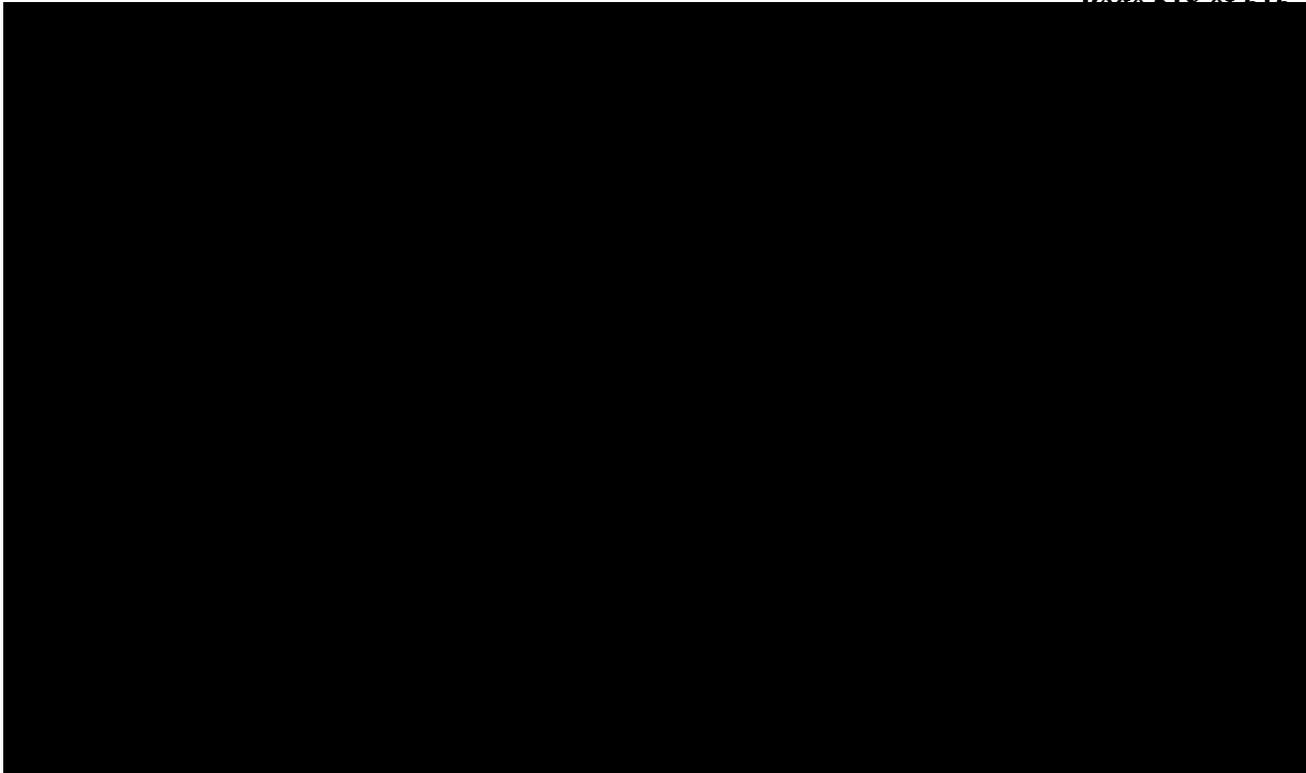
- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**
  1. Recommendation: NPVRR: ($000s) $0.6M net
     Taxes on contributions received   NPV: ($000s) ($ 2.1M)
     The recommended project is to relocate, at the request of Waste Management, the gas and electric transmission lines that bisect their Outer Loop Landfill in order to accommodate their expansion of that facility. As part of the gas location, LG&E will install a larger diameter (24") gas pipeline than the existing size gas pipeline (20"). Waste Management will pay for the cost of the relocation but will not pay for the difference in cost related to the difference in the size of the pipe. As such, 96% of the costs of this project through periodic contributions. The contributions will be taxable when received. Although Waste Management will not reimburse LG&E for the amount of the taxes paid, LG&E will recover the entire amount of the tax payments through future tax savings during the following 20 years. The Net Present Value of the tax payments, as calculated by the Corporation Tax Department outside of the CEM, is ($2.1M). Separate CEMs were completed for the electric and gas projects. The NPVRR above is the sum of both.

  2. Relocate with 20" gas pipeline   NPVRR: ($000s) $0.0M net
     Taxes on contributions received   NPV: ($000s) ($2.1M)
     To relocate, at the request of Waste Management, the gas and electric transmission lines that bisect their Outer Loop Landfill in order to accommodate their expansion of that facility using the existing 20" diameter gas pipeline. Under this alternative, Waste Management would pay 100% of the costs of the relocation through periodic contributions. However, increasing the gas pipeline diameter from 20-inches to 24-

inches supports future system planning and provides flexibility for system alignment. Although. Thus, installing a new 20" segment of pipeline is not recommended.

3. Do Nothing: NPVRR: ($000s) N/A
   Because the company transmission lines exist in private easements the company has the right to refuse to relocate. However, there is no net cost to accommodate the request and the company would risk community relation issues if such a refusal were to be portrayed as contributing to increased waste removal costs if Waste Management were forced to prematurely close their facility.

4. Relocate along a different route: NPVRR: ($000s) $0.9M net
   An alternate route along route KY 1065 (the Outer Loop) was considered but rejected due to increased length (approximately 150% longer) and due to a greater portion of the land required for it being designated wetlands. The increased length would result in more energy transmission losses for both the electric and gas transmission lines and greater maintenance costs. The larger resulting footprint in the wetlands would result in increased environmental risks with no benefit to the company.

Project Description

- **Electric Transmission Project Scope and Timeline**
  The electric transmission materials will be ordered upon project approval and after execution of the relocation agreement. Waste Management has proposed the construction of an access road around the perimeter of the fill boundary that will be within the transmission and gas easement. The final grade of the access road must be achieved before construction of the transmission line can begin as it will be a significant increase in grade. Waste Management is responsible for the construction of the access road. Once this is achieved, seven spans of the line will be constructed first (the relocated portion) and the tie in with the main circuit will need to occur during a period of low demand. The first milestone is the design of the deep drilled shaft foundations for each proposed structure location which will begin upon project approval. Once the design of the foundations is complete, construction will be scheduled. Once the tie in is complete, the existing lattice tower line will be removed.

Waste Management Access Road (begin construction)	January 2017 – March 2017
Design Foundations	May 2017 – June 2017
Order Material	January 2017
Receive Material	March 2017 – April 2017
Begin Construction (contingent on WM access road)	October 2017
Remove Lattice Towers	October – November 2018
Complete Construction	November 2018

- **Gas Project Scope and Timeline**
  The gas transmission pipeline materials will be ordered upon project approval and after execution of the relocation agreement in time for construction after the 2017-2018 heating

season. Construction is timed to allow Waste Management time to re-grade the area where though company facilities will be located. The completion is timed to provide an adequate allowance for the tie-in of the new pipeline to be made during a period of low demand.

Design and layout to be completed	October 2016
Construction contract to be awarded	May 2017*
Major materials (pipe and fittings) to be ordered	October 2017
Major materials to be received	March 2018
Construction to begin	March 2018
Construction to be completed	September 2018
Tie-in to be completed	October 2018

     * Contract award date is not set yet. A contract could be awarded as early as January 2017 if Waste Management decides to commit to gas construction work in 2018.

- **Project Cost** (Gross Costs)

	Electric	Gas	Total
Gross Cost	$9.0M	$4.4M	$13.4M
Contingency	10%	10%	

Economic Analysis and Risks

- **Bid Summary**

Electric Transmission:
Based on preliminary engineering, Transmission Lines has estimated the material package for construction of this project to be $1,593k. This project will utilize standard and custom steel structures that will be ███████████████████████████████ The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four contractors which have been awarded the T&D Overhead Construction Maintenance contracts.

Gas Transmission:
Material costs are based on a quote from ████████████████ Construction of the gas pipeline will be completed by traditional trenching methods. Gas pipeline construction bids were received from several gas pipeline contractors including contractors which have completed several pipeline projects for LG&E.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	-	29	492	-	520
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	-	29	492	-	520
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	-	(29)	(492)	-	(520)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	-	(29)	(492)	-	(520)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The project is 96% funded. There will be net capital of spend during 2018 of $0.5M. The table above and the financial calculations are based on the total gross cost of the project prior to the customer payment.

The following table reflects the impact of the advances from Waste Management:
$'000s

	2013	2016-2018	Total
Taxable Income on Advances	250	12,641	12,891
Tax Paid on Advances	(97)	(4,917)	(5,015)
Recovery of taxes paid through future tax depreciation over 20 years			5,015
NPV of Tax Paid	(40)	(2,042)	(2,082)

Financial Summary ($000s)

Discount Rate   6.5%

Capital Breakdown:

	Total	146709 Electric	148081 Gas
Labor	$ 475	$ 396	$ 79
Contract Labor	$ 7,676	$ 5,139	$ 2,538
Materials	$ 2,419	$ 1,593	$ 826
Other	$ 2	$ 1	$ 1
Local Engineering	$ 1,052	$ 641	$ 411
Burdens	$ 574	$ 440	$ 134
Contingency	$ 1,212	$ 816	$ 396
Reimbursements	$ (12,890)	$ (9,025)	$ (3,865)
Net Capital Expenditure	$ 520	$ -	$ 520

Electric	Recommendation					
Financial Analysis - By Year	**2016**	**2017**	**2018**	**2019**	**2020**	**Life of Project**
Net Income, $000s	$0	$0	$0	$0	$0	$0
ROE	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Gas	Recommendation					
Financial Analysis - By Year	**2016**	**2017**	**2018**	**2019**	**2020**	**Life of Project**
Net Income, $000s	$0	$9	$15	$19	$21	$589
ROE	0.0%	58.0%	9.9%	7.5%	9.2%	9.9%

- **Assumptions**

It is expected that a Certificate of Public Convenience and Necessity (CPCN) will be needed from the Kentucky Public Service Commission (KPSC) for the electric relocation. Approval of the CPCN is not expected to result in delays as the relocation is limited to property owned by Waste Management.

A significant amount of trash was encountered in the geotechnical analysis for the structure foundations. Poor geotechnical conditions were therefore assumed in the estimation process. This led to a highly conservative assumption for the size and installation techniques of the drilled shaft foundations. It was also anticipated that lead paint would be encountered in the lattice towers which considerably increased the estimated cost of removal.

Retirement of the old gas pipeline assumes that if PCBs (Polychlorinated Biphenyls) are detected the level will be below the thresholds that require draining and disposal of liquids or

grouting of the line. At this time Waste Management has not decided whether it will have entire length of the old pipe removed, thus its removal cost has not been included.

It is expected that the fill in which the pipeline will lay will be compacted clay and the native material will be clay with the possibility of encountering soft shale or small pockets of mixed clay and trash. It is assumed that hazardous materials will not be encountered.

It is expected the natural gas pipeline can be installed without having to use Horizontal Directional Drilling (HDD) construction methods.

Waste Management obtains all required permits.

- **Environmental**
  A lead paint inspection will precede the removal of the existing lattice towers. If lead paint is detected, special precautions will be taken when removing.

  Part of the agreement between the company and Waste Management is for Waste Management to obtain all necessary permits including environmental. It is planned for the old pipeline to be retired in place in accordance with regulations applicable to asbestos and potential PCB disposal. Environmental Affairs has been providing guidance on permit and disposal issues.

  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with the electric transmission relocation.

- **Risks**
  Potential risks for completing the project include unknown weather conditions, difficulty in coordinating work with Waste Management's site contractor, encountering unexpectedly large volumes of buried trash, etc. Completing the project subjects the company to only the direct financial risks of the difference in cost related to the increased size of pipeline; otherwise, there is no direct financial risk beyond the remote possibility that the actual cost will exceed the applicant's contribution and the applicant will not be able to pay the difference. (Senior notes issues by Waste Management in 2015 were assigned an A- rating by S&P.) Potential customer relation issues if actual costs are significantly higher than estimates.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the Transmission Relocation for Expansion of Waste Management's Outer Loop R.D.F. project for $13.4M gross capital ($0.5M net) to accommodate Waste Management's request to relocate the electric and gas transmission lines that bisect its Outer Loop recycling and disposal facility, along with approval of the associated Electric Transmission Line Relocation Contract and the Gas Transmision Line Relocation Contract which specify the scope of work and funding for the project.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LG&E and KU Investment Committee. Pursuant to the LG&E and KU Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Investment Proposal Project 153351 Adams-Millersburg Pole Replacement　　　　**Arbough**

Investment Proposal for Investment Committee Meeting on: November 29, 2016

Project Name: Adams-Millersburg Pole Replacement

Total Expenditures: $4,528k
Total Contingency: $412k (10%)

Project Number(s): 153351

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Joe Mina/Adam Smith

Executive Summary

The proposed project is to replace seventy-five (75) existing wood structures with seventy-five (75) steel structures, and one (1) existing steel switching station with one (1) steel single pole structure on the Adams-Millersburg 69kV line based on the results of a routine line inspection. The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option and it would reduce the cost by $965k   As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability.

This project is not included in the 2016 Business Plan, however is included in the proposed 2017 Business Plan under the K9-2017 Priority Pole Replacement Blanket. All spending will occur in 2017.

Background   Arbough

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. During a routine climbing inspection of the Adams-Millersburg 69kV line, seventy-six (76) structures were identified as priority poles and found to be in need of replacement. All seventy-six (76) structures need to be replaced in order to ensure the integrity and reliability of this line. There are 510 total structures along this 35.37 mile line.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $5,680k
        The recommendation is to replace the structures energized due to the difficulty in obtaining an extended outage. If the opportunity to complete the project de-energized would occur, we would pursue this option and it would reduce the cost by $965k and the NVPRR by $1,210k.
    2. Alternative #1 (Do Nothing):   NPVRR: ($000s) $8,855k
        The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
    3. Alternative #2 (Next Best Alternative):   NPVRR: ($000s) $7,357k
        The next best alternative would be to replace the seventy-five (75) of the proposed seventy-six (76) structures with wood. The manufacturer's recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing twenty-three (23) standard steel H-frame structures, forty-nine (49) standard single pole structures, one (1) custom steel single pole switch structure, one (1) steel lattice tower, one (1) steel 3-pole running corner, one (1) steel single pole running corner, and associated hardware and material, and the removal of seventy-five (75) wood structures, one (1) steel switching station, and associated hardware and material. The line construction will be based on continuing contracts from our line contractors. B&B, Elliot, Groves and Pike are the four contractors awarded the T&D Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. The contract extension was re-approved by the IC in July of 2014. Construction is scheduled to begin in January of 2017 and be completed in April of 2017.

The construction milestones for this project are provided below: **Arbough**

Construction Milestones	
November 2016	Engineering and Design
December 2016	Steel Poles Ordered
January 2017	Steel Poles Received
January 2017	Line Construction Begins
April 2017	Line Construction Completed

A facility map of the Adams-Millersburg 69kV line is shown below:
Line length: 35.37 miles
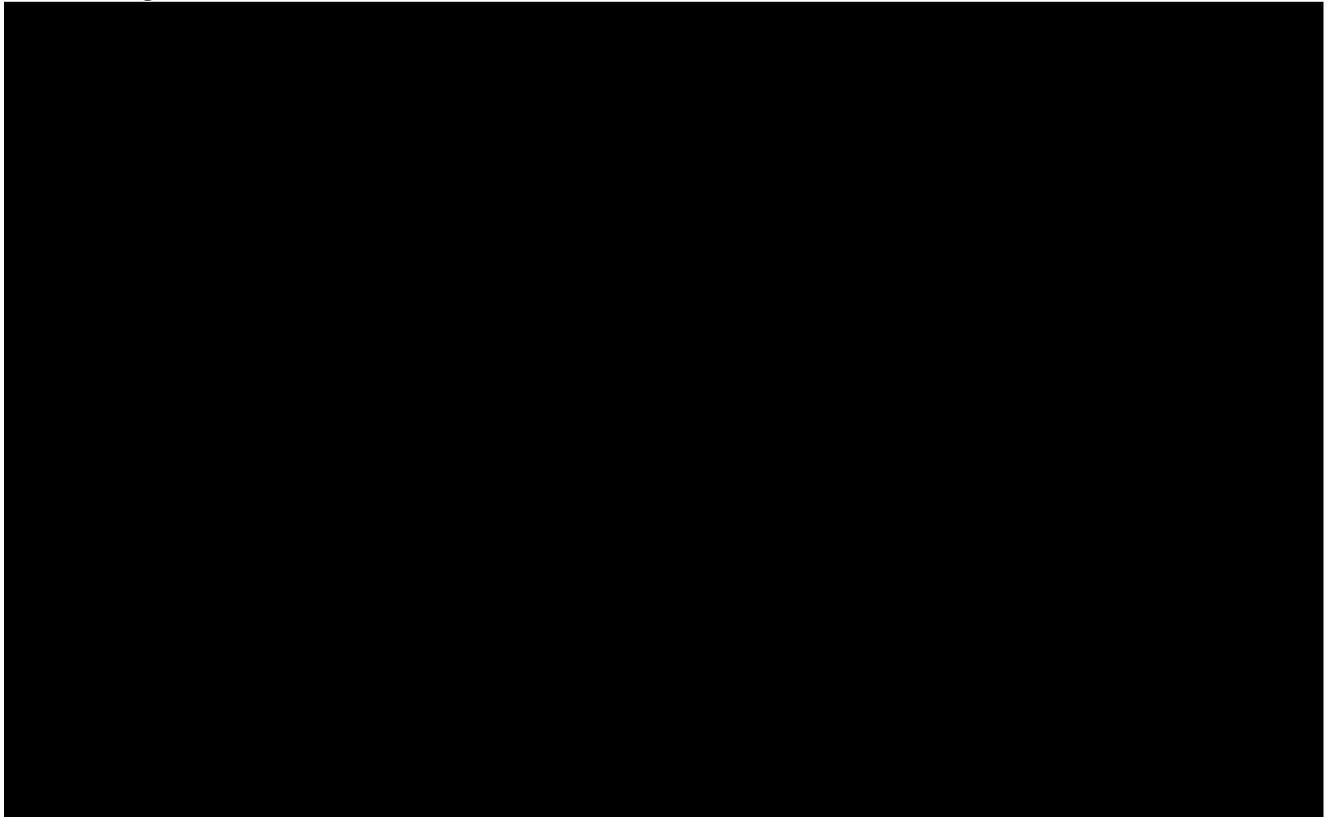
- **Project Cost**
  The total project cost is $4,528k and was not included in the 2016 Business Plan, however is included in the proposed 2017 Business Plan under the K9-2017 Priority Pole Replacement blanket. All spending will occur in 2017. Historical and existing contract and purchasing agreements were used to estimate the cost of material and contract labor. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**

Based on preliminary engineering, Transmission Lines has estimated the material package for construction of this project to be $1,119k. This project will utilize standard and custom steel structures. The steel structures will be purchased through ███████████ ████████ Hardware will be purchased through ██████████████. The line construction will be based on continuing contracts with our line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the T&D Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$1,043k
Hardware	$76k
Total	$1,119k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	3,593	-	-	-	3,593
2. Cost of Removal Proposed	935	-	-	-	935
3. Total Capital and Removal Proposed (1+2)	4,528	-	-	-	4,528
4. Capital Investment 2016 BP	-	-	-	-	-
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(3,593)	-	-	-	(3,593)
8. Cost of Removal variance to BP (5-2)	(935)	-	-	-	(935)
9. Total Capital and Removal variance to BP (6-3)	(4,528)	-	-	-	(4,528)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2017 spending is included in the proposed 2017 Business Plan under the K9-2017 Priority Pole Replacement Blanket.

Financial Summary ($000s):

Discount Rate: 6.49%

Capital Breakdown:

Labor:	$176k
Contract Labor:	$2,322k
Materials:	$1,119k
Local Engineering:	$275k
Burdens:	$224k
Contingency:	$412k
Reimbursements:	($0)
Net Capital Expenditure:	$4,528k

Financial Analysis - Project Summary ($000)	2017	2018	2019	2020	2021	Life of Project
Project Net Income	$ 96	$ 182	$ 176	$ 169	$ 163	$ 4,038
Project ROE	5.1%	7.5%	10.0%	10.0%	10.0%	9.8%

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available and the structure replacements will need to be completed with the 69kV line energized.

  Do nothing alternative – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize the construction crews. These poles would fail and require replacement within the next four years.

  Next best alternative - The cost of this alternative assumes the cost of the wood poles is 28% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Adams-Millersburg 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Adams-Millersburg Pole Replacement project for $4,528k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $1 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: November 28, 2018

Project Name: Earlington North-Green River Pole Replacement

Total Expenditures: $8,766k
Total Contingency: $797k (10%)

Project Number(s): 156689

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Addam Gooch/Adam Smith

Executive Summary
The proposed project is to replace ninety-six (96) wood structures on the Earlington North-Green River Plant 161kV line with new steel structures. The scope of work includes the replacement of eighty-nine (89) structures identified through inspection in 2017. The replacement of seven (7) additional adjacent structures is required to accommodate the height of the new structures. Due to the difficulty in obtaining an extended outage, approximately 50% of the ninety-six (96) structures will be completed energized when they are replaced. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $612k.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

This project was included in the 2019 Business Plan (BP) for $4,713k with estimated spend of $447k in 2018, $3,364k in 2019, and $902k in 2020. The current total project cost is $8,766k, with estimated spend of $178k in 2018, and $8,588k in 2019. Subsequent to the 2019 BP planning, a decision was made to complete 50% of the ninety-six (96) structures energized. In addition, seven (7) adjacent structures will need to be replaced in order to accommodate the height of the new structures. This project also includes funding for storm water pollution prevention, wetlands permitting, and entrance matting for structure access. The 2018 spend was approved by the RAC in the 11+1 forecast. Incremental funding in the amount of $5,224k will be sourced by a reallocation of other Transmission projects scheduled for 2019.

Background

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine climbing inspection of the Earlington North-Green River Plant 161kV line was completed in 2017, and eighty-nine (89) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line. The replacement of seven (7) additional adjacent structures is required to accommodate the height of the new structures. Due to the location of the structures, AECOM will be used to determine the extent of the geographic location of the wetlands area, and provide support in developing the storm water pollution prevention plan (SWPPP). Assistance will also be provided to obtain the required wetlands permitting. Access matting will also be needed to gain entrance to the structures.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $10,262
     Due to the difficulty in obtaining an extended outage, 50% of the ninety-six (96) wood structures will be completed energized when they are replaced with steel structures. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $612k and the NPVRR by $715k.
  2. Alternative #1:   NPVRR: ($000s) $15,749
     The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
  3. Alternative #2:   NPVRR: ($000s) $11,414
     The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing eighty-eight (88) steel H-frame structures, three (3) steel three pole running corners, five (5) steel dead end structures, and associated hardware and material, and the removal of ninety-six (96) wood structures, and associated hardware and material. Construction is scheduled to begin in January of 2019 and be completed in May of 2019.

Construction Milestones	Arbough
September 2018	Engineering and Design
September 2018	Space reserved for steel pole production with manufacturer
November 2018	Steel Poles Ordered to Inventory
January 2019	Steel Poles Received to Inventory
January 2019	Line Construction Begins
May 2019	Line Construction Completed

A facility map of the Earlington North-Green River Plant 161kV line is shown below:
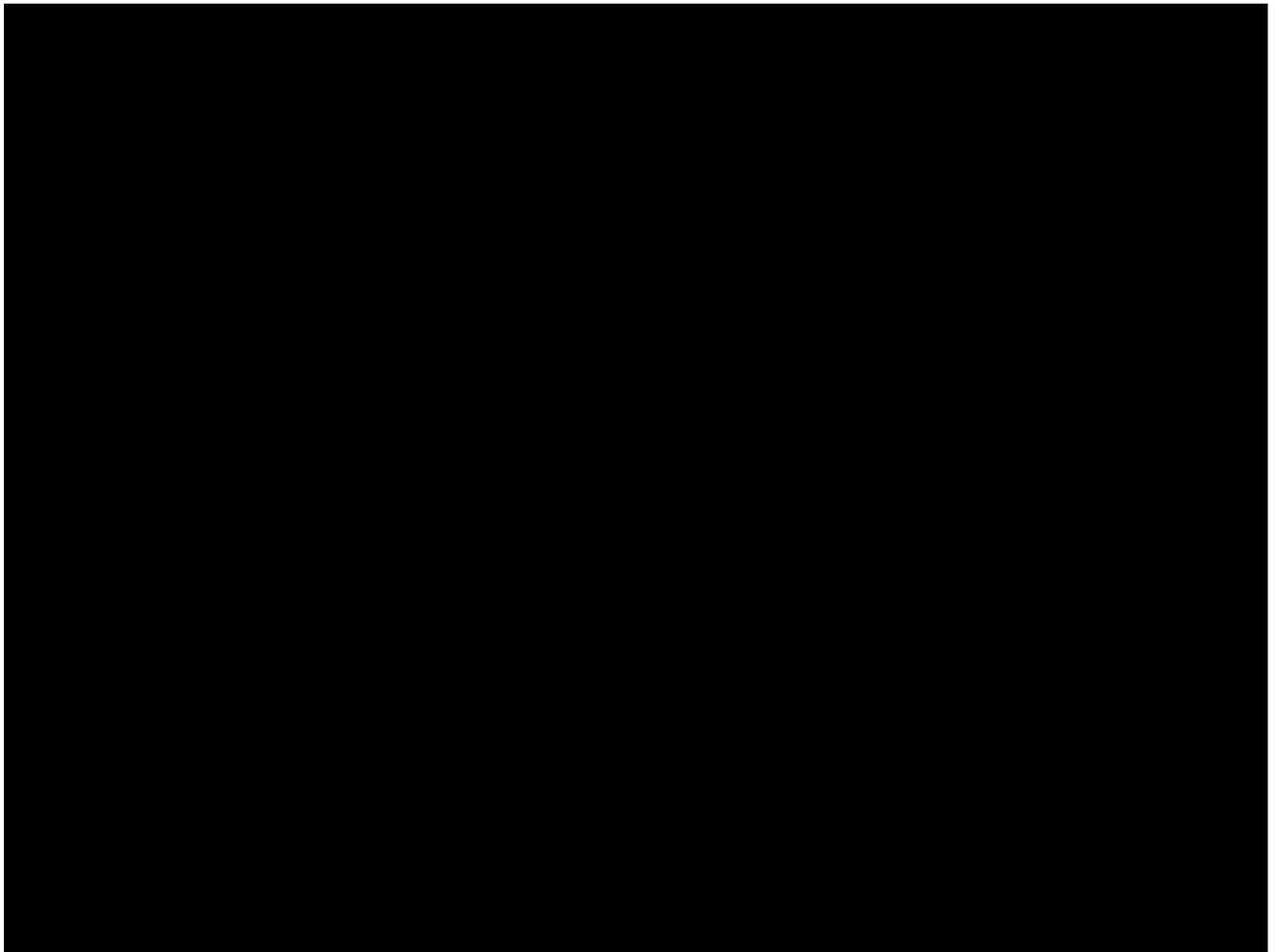
- **Project Cost**

  The current total project cost is $8,766k. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $2,405k. This project will utilize standard and custom steel structures. The steel structures will be purchased through ████████████████ ████████████████████ The line construction will be based on continuing contracts with the Company's line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the Transmission Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$2,262k
Hardware	$143k
Total	$2,405k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	178	6,935	-	-	7,113
2. Cost of Removal Proposed		1,653	-	-	1,653
3. Total Capital and Removal Proposed (1+2)	178	8,588	-	-	8,766
4. Capital Investment 2019 BP	447	3,364	902		4,713
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	447	3,364	902	-	4,713
7. Capital Investment variance to BP (4-1)	269	(3,571)	902	-	(2,400)
8. Cost of Removal variance to BP (5-2)	-	(1,653)	-	-	(1,653)
9. Total Capital and Removal variance to BP (6-3)	269	(5,224)	902	-	(4,053)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.59%

Capital Breakdown:

  Labor: $249

  Contract Labor: $4,039

  Materials: $2,412

  Local Engineering: $614

  Burdens: $655

  Contingency: $797

  Reimbursements: ($0)

  Net Capital Expenditure: $8,766

- **Assumptions**

  Recommendation – The cost of this alternative assumes that the line outage will not be available for the duration of the project, and approximately 50% of the ninety-six (96) structures will need to be completed with the 161kV line energized.

  Alternative #1 – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize construction crews. These poles would fail and require replacement within the next four years.

  Alternative #2 – The cost of this alternative assumes the cost of the wood poles is 31% the cost of the steel poles, and that the wood poles would be replaced again in 30 years. The estimated life of the steel poles is 90 years.

- **Environmental**

  There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

- **Risks**

  Without the proposed replacement of the priority poles on the Earlington North-Green River Plant 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays. Schedule delays may also occur if the required wetlands permitting is not received within the required timeframe.

Conclusions and Recommendation Arbough

It is recommended that the Investment Committee approve the Earlington North-Green River pole replacement project for $8,766k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____		_____
Kent W. Blake Date		Paul W. Thompson Date
Chief Financial Officer		Chairman, CEO and President

Investment Proposal Project 156691 Grahamville-Paducah Primary Pole Replacement Although

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Investment Proposal for Investment Committee Meeting on: October 31, 2018

Project Name: Grahamville-Paducah Primary Pole Replacement

Total Expenditures: $2,399k
Total Contingency: $218k (10%)

Project Number(s): 156691

Business Unit/Line of Business: Transmission

Prepared/Presented By: Addam Gooch/Adam Smith

Executive Summary

The proposed project is to replace thirty-five (35) wood structures on the Grahamville-Paducah Primary 161kV line with new steel structures. The scope of work includes the replacement of thirty-five (35) structures identified through inspection in 2017. Due to the difficulty in obtaining an extended outage, approximately 50% of the thirty-five (35) structures will be completed energized when they are replaced. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $199k.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

This project was included in the 2019 Business Plan (BP) for $2,280k with estimated spend of $318k in 2018 and $1,962k in 2019. The current total project cost is $2,399k, with all spending to occur in 2019. Subsequent to the 2019 BP planning, a decision was made to complete construction of the project in 2019 due to potential material delays. In addition, funding in the amount of $119k was identified for incremental site clearing. The incremental funding of $437k was funded by a reduction in the K9-2019 pole replacement blanket.

Background   **Arbough**

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine climbing inspection of the Grahamville-Paducah Primary 161kV line was completed in 2017, and thirty-five (35) structures were identified as priority poles and determined to be in need of replacement in order to ensure the integrity and reliability of this line.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $2,989
       Due to the difficulty in obtaining an extended outage, 50% of the thirty-five (35) wood structures will be completed energized when they are replaced with steel structures. If the opportunity to complete the entire project de-energized would occur, this option would be pursued and would reduce the cost by $199k and the NPVRR by $263k.
    2. Alternative #1: Do Nothing   NPVRR: ($000s) $4,298
       The alternative of do nothing would result in replacing the poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on network reliability.
    3. Alternative #2:   NPVRR: ($000s) $3,087
       The next best alternative would be to replace the poles with wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended lifespan of 90 years. This option assumes replacement of wood structures in 30 years and an escalation rate of four percent (4%) which is in line with market cost increases over the last 15 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing twenty-nine (29) standard steel H-frame structures, six (6) steel three pole running corner, and associated hardware and material, and the removal of thirty-five (35) wood structures, and associated hardware and material. Construction is scheduled to begin in January of 2019 and be completed in May of 2019.

Construction Milestones	
August 2018	Engineering and Design
August 2018	Space reserved for steel pole production with manufacturer
November 2018	Steel Poles Ordered
January 2019	Steel Poles Received
January 2019	Line Construction Begins
May 2019	Line Construction Completed

A facility map of the Grahamville-Paducah Primary 161kV line is shown below:
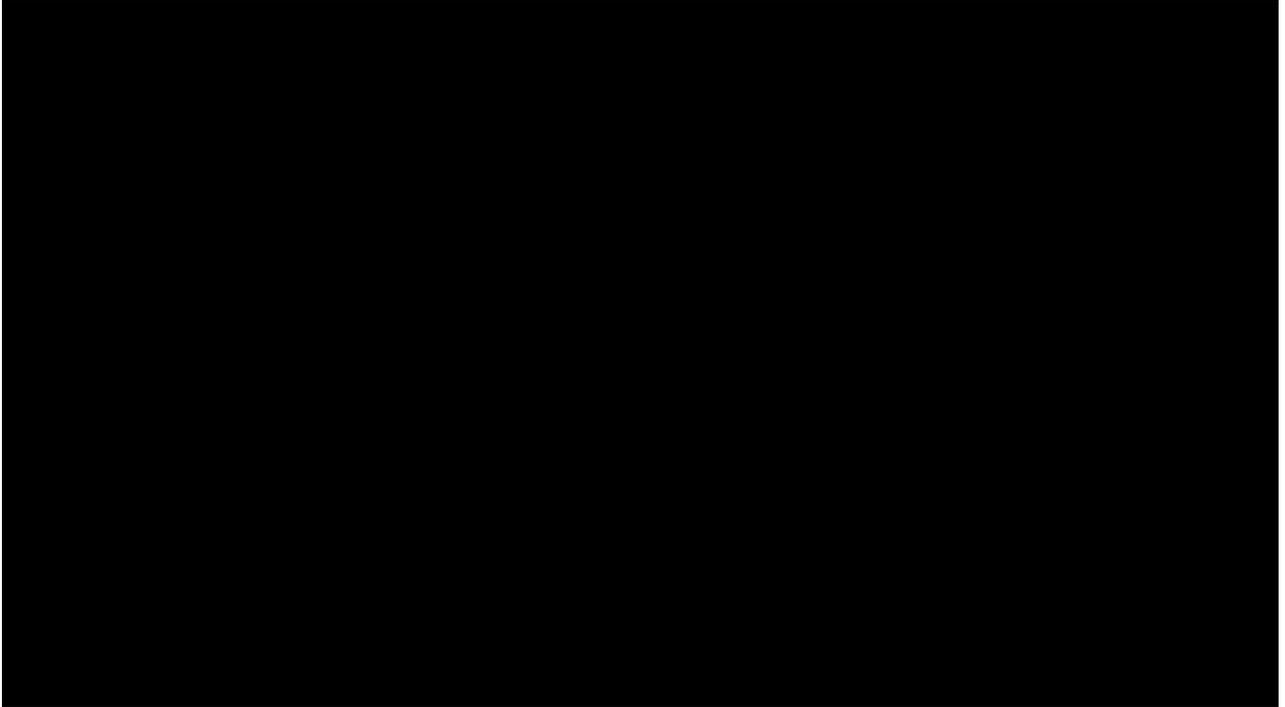
- **Project Cost**

The current total project cost is $2,399k. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**

Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $861k. This project will utilize standard steel structures. The steel structures will be purchased through ███████████████████ ███████████. The line construction will be based on continuing contracts with the Company's line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the Transmission Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$809k
Hardware	$52k
Total	$861k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	-	2,051	-	-	2,051
2. Cost of Removal Proposed	-	348	-	-	348
3. Total Capital and Removal Proposed (1+2)	-	2,399	-	-	2,399
4. Capital Investment 2019 BP	318	1,962	-	-	2,280
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	318	1,962	-	-	2,280
7. Capital Investment variance to BP (4-1)	318	(89)	-	-	229
8. Cost of Removal variance to BP (5-2)	-	(348)	-	-	(348)
9. Total Capital and Removal variance to BP (6-3)	318	(437)	-	-	(119)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary:

Discount Rate: 6.59%

Capital Breakdown:

Labor:	$52k
Contract Labor:	$902k
Materials:	$861k
Local Engineering:	$166k
Burdens:	$200k
Contingency:	$218k
Reimbursements:	($0)
Net Capital Expenditure:	$2,399k

- **Assumptions**

Recommendation – The cost of this alternative assumes that the line outage will not be available for the duration of the project, and approximately 50% of the thirty-five (35) structures will need to be completed with the 161kV line energized.

Alternative #1 – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize construction crews. These poles would fail and require replacement within the next four years.

Alternative #2 – The cost of this alternative assumes the cost of the wood poles is 35% of the cost of the steel poles, and that the wood poles would be replaced again in 30 years. The estimated life of the steel poles is 90 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Grahamville-Paducah Primary 161kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Grahamville-Paducah Primary pole replacement project for $2,399k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:		DocuSigned by:	
Kent Blake	11/2/2018 | 8:42 AM EDT	*Paul Thompson*	11/8/2018 | 6:27 AM EST
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Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal Project LI-000030 Lancaster-Danville East Pole ReplacementArbough

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Investment Proposal for Investment Committee Meeting on: September 26, 2018

Project Name: Lancaster-Danville East Pole Replacement

Total Expenditures: $3,107k
Total Contingency: $282k (10%)

Project Number(s): LI-000030

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Addam Gooch/Adam Smith

Executive Summary
The proposed project is to replace eighty-six (86) wood structures, on the Lancaster-Danville East 69kV line with new steel structures during a scheduled outage. The scope of work includes the replacement of sixty-four (64) structures identified through inspection in 2017. The replacement of twenty-two (22) additional adjacent structures is required to accommodate the increased height of the new structures. This project will begin in January of 2019 and is being submitted for approval in 2018 to ensure the project will be open and ready for charges beginning January 1, 2019.

The alternative of replacing poles upon failure will result in much higher long term replacement costs due to mobilization of crews back to the site each time one fails and the probable overtime work involved in replacing each during an emergency situation. This alternative would also have a negative impact on network reliability. As such, this proposal is to proactively replace them over the course of the next year, prior to failure, to ensure the integrity and reliability of this line and to prevent outages resulting from such failures.

This project was included in the 2018 Business Plan (BP) for $3,200k for work to be completed in 2019. The current total project cost is $3,107k and is consistent with the proposed 2019 BP.

Background   **Arbough**

Above ground pole inspections are performed by the company at defined intervals in order to discover problems that may impact the integrity and reliability of the Transmission System. A routine climbing inspection of the Lancaster-Danville East 69kV line was completed in 2017, sixty-four (64) structures were determined to be in need of replacement in order to ensure the integrity and reliability of this line. In addition, twenty-two (22) additional adjacent structures will also need to be replaced in order to accommodate the height of the new structures.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $3,871
     The recommendation is to replace all eighty-six (86) wood structures with new steel structures during a scheduled outage.
  2. Alternative #1:   NPVRR: ($000s) $5,568
     The alternative of do nothing would result in replacing poles upon failure, which would result in a much higher long term replacement cost due to contract crew mobilization and overtime costs. This cost was derived by an estimated percentage of failure over the next four years. The failure rate and costs may vary depending on environmental factors. This option would also have a negative impact on reliability.
  3. Alternative #2:   NPVRR: ($000s) $4,042
     The next best alternative would be to replace eighty-six (86) existing wood structures with new wood structures. The recommended life span of a wood pole is 30-35 years, whereas steel poles have a recommended life span of 90 years. This option assumes replacement of wood structures in 30 years and an escalation factor of 4% which is in line with market cost increases over the last 15 years.

Project Description

- **Project Scope and Timeline**
  The scope of work will consist of installing sixty-five (65) standard steel Z-frame structures, three (3) steel single-pole running corners, two (2) steel single pole dead end structures, sixteen (16) standard steel H-frame structures, and associated hardware and material, and the removal of eighty-six (86) wood structures, and associated hardware and material. The line construction will be based on continuing contracts from the Company's line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors awarded the Transmission Overhead Construction and Maintenance contract from the October 2011 Investment Committee meeting. A two-year optional contract extension was approved by the IC in April of 2017. Construction is scheduled to begin in January of 2019 and be completed in June of 2019.

Construction Milestones	
June 2018	Engineering and Design
July 2018	Space Reserved with Steel Pole Manufacturer
October 2018	Steel Poles Ordered to Inventory

January 2019	Steel Poles Removed from Inventory**Arbough**
January 2019	Line Construction Begins
June 2019	Line Construction Completed

A facility map of the Lancaster-Danville East 69kV line is shown below:

- **Project Cost**
  This project was included in the 2018 Business Plan (BP) for $3,200k for work to be completed in 2019. The current total project cost is $3,107k and is consistent with the proposed 2019 BP. This project contains a 10% contingency which is reasonable based on the level of detailed engineering, confidence in cost of materials and contractors, and potential unknown risks such as weather delays, rock, structure access, and potential outage restrictions.

Economic Analysis and Risks

- **Bid Summary**
  Based on preliminary engineering, Transmission Lines has estimated the material packages for construction of this project to be $1,062k. This project will utilize standard steel structures. The steel structures will be purchased through ███████████████ ████████████████████ The line construction will be based on continuing contracts with the Company's line contractors. Davis H. Elliot, Pike Electric, B&B Electric and William E. Groves are the four main contractors which have been awarded the Transmission Overhead Construction and Maintenance contracts.

Transmission Lines Material Cost Breakdown	
Material	**Cost**
Steel Poles	$1,010k
Hardware	$52k
Total	$1,062k

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	-	2,588	-	-	2,588
2. Cost of Removal Proposed	-	519	-	-	519
3. Total Capital and Removal Proposed (1+2)	-	3,107	-	-	3,107
4. Capital Investment 2018 BP	-	3,200	-	-	3,200
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	-	3,200	-	-	3,200
7. Capital Investment variance to BP (4-1)	-	612	-	-	612
8. Cost of Removal variance to BP (5-2)	-	(519)	-	-	(519)
9. Total Capital and Removal variance to BP (6-3)	-	93	-	-	93

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.59%

Capital Breakdown:

Labor:	$78
Contract Labor:	$1,213
Materials:	$1,062
Local Engineering:	$214
Burdens:	$258
Contingency:	$282
Reimbursements:	($0)
Net Capital Expenditure:	$3,107

- **Assumptions**

Recommendation – The cost of this alternative assumes that the line outage will be available for the duration of the project, and all eighty-six (86) structures will be completed during the scheduled outage.

Alternative #1 – The cost of this alternative would be approximately 60% higher due to overtime labor charges and the cost to mobilize and demobilize construction crews. These poles would fail and require replacement within the next four years.

Alternative #2 – The cost of this alternative assumes the cost of the wood poles is 35% the cost of the steel poles, and that the wood poles would be replaced again in 30 years. The estimated life of the steel poles is 90 years.

- **Environmental**
  There are no known environmental issues regarding air, water, lead asbestos, etc., associated with this project.

- **Risks**
  Without the proposed replacement of the priority poles on the Lancaster-Danville East 69kV line, the company risks unplanned outages and increased cost of repairs in emergency situations. Inclement weather which affects site access and working conditions could increase the project cost and cause schedule delays.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Lancaster-Danville East Pole Replacement project for $3,107k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by: DocuSigned by:

Kent Blake   *Kent Blake* DOA for Paul Thompson
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Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: April 25, 2018

Project Name: Mobile Control House

Total Expenditures: $2,727k   (Including $249k of contingency)

Project Number(s): 151465

Business Unit/Line of Business: Transmission

Prepared/Presented By: Aaron Burns, Sargent & Lundy/Brent Birchell

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Executive Summary

Transmission has initiated a strategic objective to improve the overall resiliency of the LG&E/KU (LKE) grid. The two primary components of this plan consist of: 1) Physical Security improvements to mitigate threats to the Transmission Substation facilities and 2) Procurement of spare equipment required to recover from a High Impact Low Frequency (HILF) event.   Although our comprehensive resiliency program is not required for compliance, there has been an increased focus on the resiliency of the grid.

Existing LG&E/KU transmission protection and control (P&C) equipment is typically contained in a single control house located at each site. A catastrophic event at a control house would cause a complete loss of transmission P&C equipment resulting in a prolonged transmission outage of multiple lines and transformer capacity. Complete restoration of a control house could take 18-24 months and the station would be inoperable during this time.

By procuring a Mobile Control House, LKE would gain the option of deploying a prefabricated control house capable of restoring a sufficient level of P&C functionality at any existing station. The Mobile Control House can be deployed at any time without the need of permits, special tools, or special equipment. Obtaining a Mobile Control House will reduce the restoration time for the loss of a control house from 18–24 months down to 4-8 weeks.

The total cost of this project will be $2,727k with $1k in 2017, $538k in 2018 and $2,188k in 2019. This project was included in the 2018 BP for $3,959k with $75k in 2017, $419k in 2018 and $3,465k in 2019. The project is being accelerated to address the immediate need to strengthen LKE's resiliency posture instead of waiting on construction and delivery of the mobile control house in 2019. The higher estimated spending during 2018 will be addressed by the RAC in the 3+9 forecast.

Background   Arbough

The impact of a complete control house failure at a transmission station would have a severe impact on the LKE transmission system. The sudden and complete loss of transmission P&C at any station could take as long as 18-24 months to completely restore. The use of a Mobile Control House could reduce station restoration time down to 1-2 months and would provide adequate P&C functionality while a permanent control house is reconstructed and commissioned.

P&C needs at critical LG&E/KU stations such as ████████████████████ ████ were considered during preliminary engineering of the Mobile Control House. P&C needs at these stations were accounted for in the preliminary engineering design to ensure that a single Mobile Control House would be capable of supporting the needs at any existing LG&E/KU station. The preliminary Mobile Control House design includes 23 standard LG&E/KU relay panels with microprocessor based protection schemes for Transformers, Transmission Lines, Bus Differentials, and UPLC transceivers. Additionally the Mobile Control House will contain a metering panel, SCADA, telecomm racks, and AC & DC panelboards. The preliminary control house layout is shown below.

Existing mobile control house solutions owned by other utilities (████ & ████████████████) were examined and considered during preliminary engineering for the project. The dimensions of the preliminary layout are based on standard ISO shipping container sizes, similar to what Southern Company utilizes for its mobile control house. This design offers the greatest amount of mobility for the unit as it can be deployed quickly without requiring any special transportation permits. Once deployed to a site, the mobile control house will be connected to existing

equipment with control cables that enter the termination cabinets through floor openings. Although mobile control house is intended to be utilized for emergency service restoration and will not be considered as a permanent solution for any control house replacement.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,824
     It is recommended that a Mobile Control House be procured to increase reliability of the LG&E/KU transmission system by minimizing restoration time in the event of a catastrophic control house failure.

  2. Purchase two traditional small control houses: NPVRR: ($000s) $3,036
     This option is not advisable as the width of a traditional control house is 14 ft and would require special permitting to transport. This option lacks the mobility needed and requires additional time for the concrete pads to be installed and trenches to be dug. Additional deployment time is estimated at 1-2 months.

  3. Do Nothing: NPVRR: ($000s) N/A
     This option is not advisable as it would leave the LG&E/KU transmission system in an undesirable state in the event of a catastrophic control house failure. As noted above, restoration time would be 18-24 months and is therefore unadvisable. This alternative is not in alignment with the resiliency program strategic objectives.

Project Description

- **Project Scope and Timeline**

Description	Date
Preliminary Engineering	2/1/18
Submit RFP for Control House	5/1/18
Detailed Engineering Start	5/11/18
Engineering Complete	9/20/18
Receive Mobile Control House	1/7/19
Begin Testing and Check-Out	1/14/19
Complete Testing and Check-Out	4/15/19
Project Complete	4/30/19

- **Project Cost**

  The total cost of this project will be $2,727k with $1k in 2017, $538k in 2018 and $2,188k in 2019. This project was included in the 2018 BP for $3,959k with $75k in 2017, $419k in 2018 and $3,465k in 2019. The estimated total project figure includes a 10% contingency. This contingency is reasonable based on the level of detailed engineering and is expected to cover uncertainty with the material and contract labor costs based upon variances that have been observed on past projects.

Economic Analysis and Risks

- **Bid Summary**
  Bids for the Mobile Control House will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	1	538	2,188	-	-	2,727
2. Cost of Removal Proposed	-	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	1	538	2,188	-	-	2,727
4. Capital Investment 2018 BP	75	419	3,465	-	-	3,959
5. Cost of Removal 2018 BP	-	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	75	419	3,465	-	-	3,959
7. Capital Investment variance to BP (4-1)	74	(119)	1,277	-	-	1,232
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	74	(119)	1,277	-	-	1,232

Financial Detail by Year - O&M ($000s)	2017	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)		-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.58%
Capital Breakdown:
  Labor: $24
  Contract Labor: $521
  Materials: $1,535
  Local Engineering: $193
  Burdens: $205
  Contingency: $249
  Reimbursements: ($-)
  Net Capital Expenditure: $2,727

- **Assumptions**
Equipment lead time is similar to that of a standard control building. The Mobile Control House will be stored at an existing LKE facility.

- **Environmental**
This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
The Mobile Control House is intended to be deployed during emergency situations, and therefore incurs minimal or no risk at this time.

Conclusions and Recommendation   **Arbough**

It is recommended that the Investment Committee approve the Mobile Control House project for $2,727k to improve the overall resiliency of the LKE grid.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul W. Thompson Date
Chief Financial Officer	Chairman, CEO and President

Capital Investment Proposal   **Arbough**

Investment Proposal for Investment Committee Meeting on: April 26, 2017

Project Name: Spare 345/161 X 138kV, 450 MVA Transformer Purchase

Total Expenditures: $3,323k (Including $302k of Contingency)

Project Number(s): 151750

Business Unit/Line of Business: Transmission Substation Construction & Maintenance

Prepared/Presented By: Chris Talley – Director Transmission Engineering and Construction

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Executive Summary
In November 2016, the North American Electric Reliability Corporation's (NERC) Reliability
Issues Steering Committee (RISC) issued recommendations to the NERC Board of Trustees
outlining strategic priorities of risks to the reliable operation of the bulk power system. Extreme
natural events (hurricanes, tornadoes, extreme temperatures, geomagnetic disturbances,
earthquakes, etc.) and physical security vulnerabilities are two of the nine risk profiles identified.
Extreme natural events, physical attacks and fire are examples of threats that, while having a low
probability of occurrence, can have a crippling effect on reliability of the electric grid if they
occur at certain locations. An evaluation of the loss of certain critical LG&E and KU (LKE)
substations was undertaken to determine the vulnerability of the system to extreme events. That
analysis shows that loss of certain key facilities could result in the inability to serve all firm load
for extended periods of time.   As indicated in the RISC report, "resilience and recovery actions
can mitigate exposure from multiple risks." One of the primary recommendations from the RISC
analysis is to focus on spare equipment strategies both to identify critical equipment and to
consider transportation logistics and requirements for replacing critical assets. NERC has
identified the limited availability of large power transformers as a "potential issue for critical
infrastructure resilience in the United States". While it is not possible to mitigate every threat,
utilities should be prepared to recover from the loss of key critical facilities. Maintaining an
adequate inventory of long lead, critical spares is a cost effective measure to help mitigate the
threat of low probability high impact event. This proposal recommends the purchase of a new
spare 345/161 X 138kV, 450 MVA Transformer to ensure adequate reserves of critical
transformers which can have a lead time of more than nine months.

The total cost of this project will be $3,323k, with $2,237k spending in 2017 and $1,086k
spending in 2018. $3,200k of funding was included in the 2017 BP for this project, with $75k
budgeted in 2017 and $3,125k budgeted in 2018. The unbudgeted amount in 2017 was approved
by the RAC in the 3+9 forecast.

Background
Specific to the LKE system, planning studies have indicated that it will take (2) 345/138kV
450MVA transformers to recover from a disaster scenario where multiple transformers at a

critical substation in the Louisville area are destroyed or severely damaged. ▮▮▮▮▮▮▮▮gh
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▮▮▮▮▮▮▮▮ An additional spare transformer is recommended so that LKE has adequate spares
to recover from a catastrophic event at this location.

There are (19) 345/138kV transformers and (3) 345/161kV transformers in service. Since April
of 2011, there have been (3) 345/138kV transformer failures. The Appendix shows a graph of
the ages of the 345kV transformers in the LKE System. This additional spare can be considered
not only a spare to recover from a disaster scenario, but it would also be considered an additional
spare in the event of loss of two 345kV transformers within a year.   This spare transformer will
be specified and located to ensure ability to get it to critical locations will be possible in a
reasonable time frame.

This proposal does not recommend further purchases to mitigate the threat of a coordinated
physical attack on multiple locations, or a widespread catastrophic event damaging transformers
at multiple locations. To address that threat, LKE is a member of the EEI Spare Transformer
Equipment Program (STEP) which facilitates the sharing of spare transformers in the event of a
terrorist attack and resulting declaration of emergency by the President of the United States. LKE
is also leading the development of a new mutual assistance group for transmission equipment
called RESTORE.   The vision of RESTORE is to proactively create a pool of spare transformers
that will be sold between members in the event of a catastrophic event in which one member is at
risk of not being able to serve significant load for an extended period and has exhausted all of its
available spares.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $3,884k
       It is recommended that a spare 345/161X138, 450 MVA transformer be purchased to
       reduce the potential risk to the Transmission system.

    2. Alternative #1:   NPVRR: ($000s) $7,769k
       An alternative to LKE's resilient spare is to purchase a highly optimized transformer
       specifically designed for HILF events. These types of transformers reduce the
       installation time by weeks but have a much shorter life due to design. These
       transformers are new in design true to the nature of the response and reliability has
       not yet been proven.

    3. Do Nothing: NPVRR: ($000s) N/A
       This is not recommended as this is a strategic initiative to mitigate a low probability,
       very high consequence risk and to ensure adequate spares for the 345-138 and 161kV
       systems to mitigate the risk of transformer failure from routine causes.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved	April, 2017
Materials Ordered	May, 2017
Engineering Complete	July, 2017
Construction Complete (Foundation, Oil Containment)	Sept, 2017
Materials Received	Jan, 2018
Project Complete	April, 2018

- **Project Cost**
The total cost of this project will be $3,323k, with $2,237k spending in 2017 and $1,086k spending in 2018. $3,200k of funding was included in the 2017 BP for this project, with $75k budgeted in 2017 and $3,125k budgeted in 2018. The unbudgeted amount in 2017 was approved by the RAC in the 3+9 forecast. The estimated total project figure includes a 10% contingency. This contingency is expected to cover uncertainty with the cost of the transformer as the market has been volatile over the past few years.

Economic Analysis and Risks

- **Bid Summary**
This transformer will be bid out and awarded immediately after Investment Committee approval. The bid evaluation process will closely follow previous transformer purchases.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,237	1,086	-	-	3,323
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	2,237	1,086	-	-	3,323
4. Capital Investment 2017 BP	75	3,125	-	-	3,200
5. Cost of Removal 2017 BP	-	-	-	-	-
6. Total Capital and Removal 2017 BP (4+5)	75	3,125	-	-	3,200
7. Capital Investment variance to BP (4-1)	(2,162)	2,039	-	-	(123)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(2,162)	2,039	-	-	(123)

Financial Detail by Year - O&M ($000s)	2017	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):   **Arbough**

Discount Rate: 6.5%

Capital Breakdown:

   Labor: $47k

   Contract Labor: $150k

   Materials: $2,432k

   Other: $0k

   Local Engineering: $304k

   Burdens: $88k

   Contingency: $302k

   Net Capital Expenditure: $3,323k

- **Assumptions**

  The cost of the transformer is based on estimates from vendors and based on costs of previously purchased 345kV, 450MVA transformers.

- **Environmental**

  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**

  Alternate transformer designs will be considered to address transportation concerns. An attempt will be made to limit the overall shipping dimensions and weight, which may introduce additional costs.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Spare 345/161X138kV, 450 MVA Transformer Purchase project for $3,323k.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake   Paul W. Thompson
Chief Financial Officer   President and Chief Operating Officer

Age of installed 345kV Transformers on the LKE system:
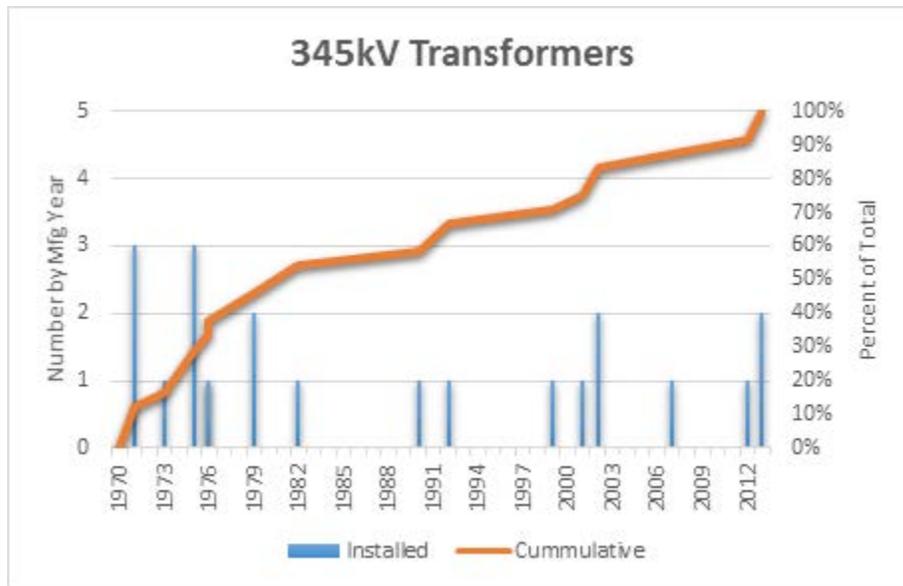
Capital Investment Proposal   **Arbough**

Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: Upgrade Rodburn & Farmers 138/69kV Transformers; Spare 138/69kV Transformer Purchase

Total Expenditures: $2,852k (Including $285k of contingency)

Project Number(s): 144488 (Rodburn), 153518 (Farmers), 153590 (Spare Transformer)

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer – Director, Transmission Strategy & Planning

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Executive Summary

The Rodburn and Farmers 138/69kV transformer replacements are a Transmission Expansion Plan (TEP) project which is required to prevent the overload of both the existing Rodburn and Farmers transformers during winter peak conditions. The Rodburn 138/69kV transformer overloads during the loss of the Rodburn to Farmers to Spencer Road 138kV line. The Farmers transformer overloads during the loss of the Rodburn 138/69kV transformer. The existing Farmers transformer has a winter emergency rating of 58 MVA and the existing Rodburn transformer has a winter emergency rating of 82 MVA. At the completion of the project, the winter emergency ratings will be 82 MVA at Farmers and 122 MVA at Rodburn. The replaced transformers are not expected to overload for extreme cold weather conditions within the ten year load forecast.

This project will install a spare transformer currently located at the Loudon Avenue substation to Rodburn and relocate the existing Rodburn transformer to Farmers where it will replace the transformer currently in-service there. The (3) single phase transformers removed from Farmers will be scrapped. The project also includes replacement of two 69kV breakers at Rodburn that have a breaker duty overload as a result of the new transformer installation. A spare transformer will be purchased to replace the spare and will be stored at Louden Avenue.

The total cost of this project is $2,852k. This project was not included in the 2016 BP. $4,937k of funding was included in the 2017 BP under projects 144488 and 151809, $2,179k in 2017 and $2,758k in 2018. The funding originally budgeted for this project was based on adding a second 138/69 transformer at Rodburn along with the associated protection and controls work (alternative #1) but after further analysis, the recommended option was determined to be the least cost solution to serve customers.

Background   **Arbough**

The overload of the Rodburn and Farmers transformers was identified in the Transmission
Expansion Planning (TEP) process and approved by the Company and TranServ, the Company's
Independent Transmission Organization (ITO).

During peak winter conditions, an outage of the Rodburn transformer results in an overload of
the Farmers transformer and an outage of the Rodburn to Farmers to Spencer Road 138kV line
results in an overload of the Rodburn transformer. A rating increase of both transformers is
required to prevent them from overloading and interrupting service to customers. The map
below shows the location of these substations and the surrounding area.

The Rodburn 138/69kV transformer has an existing winter emergency rating of 82 MVA when
adjusted for winter ambient temperatures. The Farmers 138/69kV transformer has an existing
winter emergency rating of 58 MVA when adjusted for winter ambient temperatures. During the
2018/19 winter analysis, the Rodburn loading is 84.0 MVA (105.7%), and the Farmers loading is
58.9 MVA (105.4%). After moving and replacing the transformers, the new winter emergency
rating at Rodburn will be 122 MVA and at Farmers will be 82 MVA. The Rodburn transformer
loads to 106.7 MVA and the Farmers loads to 60.6 MVA in the 2026/27 Winter Peak during
extreme cold weather conditions. Therefore the replacement transformers are expected to meet
the high load forecast for the ten year planning horizon and beyond. The project was confirmed
using the October 2015 load forecast.

The figure below shows the Rowan County area and the location of the Rodburn and Farmers
substations.
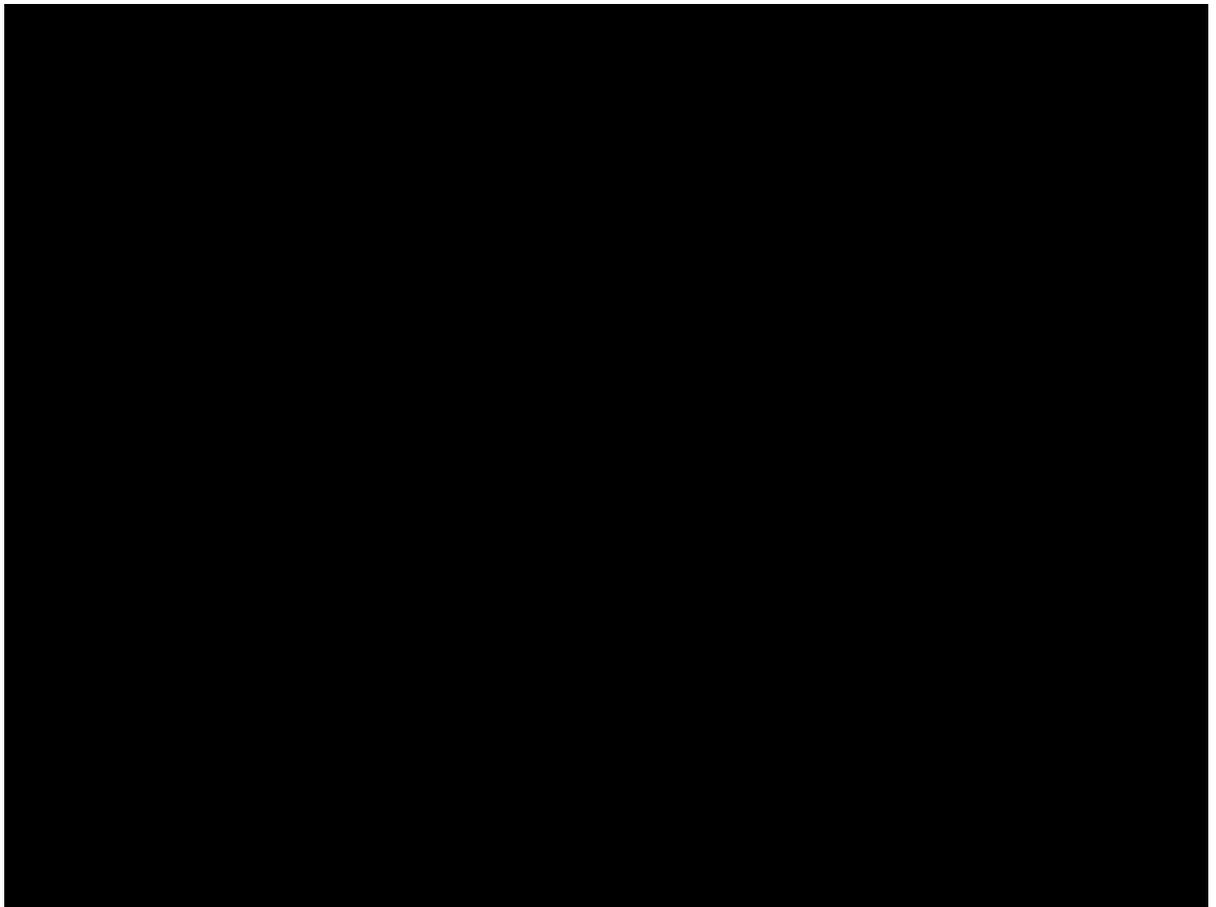
- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $3,276k
        Replace the existing Rodburn transformer with an existing spare transformer and
        relocate it to Farmers. Purchase a new spare transformer. The single phase
        transformers at Farmers will be scrapped.

    2. Alternative #1:   NPVRR: ($000s) $5,472k
        Add a second transformer at Rodburn. Adding a second transformer at Rodburn also
        requires adding breakers, switches, bus, and equipment in the control house. This
        alternative has a higher cost than the recommendation.

    3. Alternative #2:   NPVRR: ($000s) $5,609k
        Add a reactor at Rodburn to relieve loading on both the existing Rodburn and
        Farmers transformers and delay the recommended option until 2028.   This
        alternative has a higher cost than the recommendation.

    4. Do Nothing: NPVRR: ($000s) $0k
        This alternative puts customer load at risk and violates NERC TPL-001-4 reliability
        standard and the Companies' Transmission Planning Guidelines.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Originally Approved	December, 2016
Materials Ordered	January, 2017
Materials Received	October, 2017
Rodburn Construction Begins	April, 2017
Rodburn Construction Completed	May, 2017
Farmers Construction Begins	August, 2017
Farmers Construction Completed	September, 2017
Project Complete	November, 2017

- **Project Cost**
    The total cost of this project will be $2,852k. This project was not included in the 2016 BP.
    $4,937k of funding was included in the 2017 BP for this under projects 144488 and 151809,
    $2,179k (2017) and $2,758k (2018). The funding originally budgeted for this project was
    based on adding a second 138/69 transformer at Rodburn along with the associated
    protection and controls work (alternative #1). The estimated total project figure includes a
    10% contingency based on the level of detailed engineering.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,731	-			2,731
2. Cost of Removal Proposed	121	-			121
3. Total Capital and Removal Proposed (1+2)	2,852	-	-	-	2,852
4. Capital Investment 2017 BP	2,179	2,758			4,937
5. Cost of Removal 2017 BP	-	-			-
6. Total Capital and Removal 2017 BP (4+5)	2,179	2,758	-	-	4,937
7. Capital Investment variance to BP (4-1)	(552)	2,758	-	-	2,206
8. Cost of Removal variance to BP (5-2)	(121)	-	-	-	(121)
9. Total Capital and Removal variance to BP (6-3)	(673)	2,758	-	-	2,085

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2017 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$182k
Contract Labor:	$878k
Materials:	$1,170k
Other:	$0k
Local Engineering:	$164k
Burdens:	$173k
Contingency:	$285k
Reimbursements:	($0k)
Net Capital Expenditure:	$2,852k

Project Name	Project #	2017
TEP-Rodburn 138/69kV Xfmr	144488	$915k
TEP-Farmers Xfmr Upgrade	153518	$527k
ROR-Spare Xfmr-KU	153590	$1,410k
Total		**$2,852k**

- **Assumptions**
  - Current scoping parameters do not include the replacement of the back-up station service transformer nor three 138kV coupling capacitor relocations.
  - Project coordination with ▇▇▇ and ▇▇▇▇, both of which have load and assets nearby, will not result in timeline adjustments or additional costs.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos. The SPCC plan for the Rodburn and Farmers station will be revised to reflect the additional oil in the new transformer.

- **Risks**
  In order to install the transformer, the Rodburn and Farmers 138/69 transformer will need to be out of service for an estimated duration of ▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇ ▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇▇

Conclusions and Recommendation

Approve the upgrades to both the Rodburn & Farmers 138/69kV transformers and purchase of a new spare 138/69kV transformer for $2,852k to enhance the reliability of the Transmission system and serve customers.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

_____   _____
Kent W. Blake.   Victor A. Staffieri
Chief Financial Officer   Chairman, CEO and President

Capital Investment Proposal   **Arbough**

Investment Proposal for Investment Committee Meeting on: August 31, 2016

Project Name: West Lexington Reactor Additions

Total Expenditures: $1,283k (Including $117k of contingency)

Project Number(s): 149705

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer – Director Transmission Strategy & Planning

Executive Summary

The West Lexington Reactor Additions project is a Transmission Expansion Plan (TEP) project which is required to prevent the overload of (2) 138kV lines at the West Lexington substation. TEP analyses show that during summer peak conditions, the West Lexington to Viley Road line overloads during an outage of West Lexington to Haefling line and the West Lexington to Haefling line overloads during the outage of West Lexington to Viley Road line.   Therefore, this project is proposed in order to comply with the LG&E and KU (the Companies') Transmission Planning Guideline requirements and the North American Electric Reliability Corporation (NERC) TPL-001-4 Reliability Standard.

The scope of this project is to purchase and install reactors to each of these lines in the West Lexington substation, which adds impedance to each line. The increased impedance reduces flows on these constrained lines by diverting flow to other lines that have available capacity. Adding reactors is expected to be a long term solution and delays the need to reconductor these two 138kV lines from 2017 to beyond the ten year planning horizon.

The total cost of this project is $1,283k and was approved by the RAC in the 2016 7+5 forecast. $3,000k of funding was included in the 2016 Business Plan (BP) under project 149705 and 149706 (149706 is no longer needed and has been cancelled). As detailed scoping and development progressed, the estimated cost decreased. The estimated cost includes a 10% contingency.

Background

The overload of the West Lexington to Viley Road line during an outage of the West Lexington to Haefling line and the overload of the West Lexington to Haefling line during an outage of the West Lexington to Viley Road line was initially identified in the 2013 Transmission Expansion Plan, confirmed in subsequent Transmission Expansion Plans, and confirmed by TranServ, the Company's Independent Transmission Organization. This overload was further analyzed and confirmed utilizing the recent 2017 Business Plan Electric Sales Forecast.

The existing summer emergency rating of each line is 265 MVA based on the limiting element of the overhead 795 MCM 26X7 aluminum conductor steel-reinforced (ACSR) conductor. During a summer peak scenario and with the contingency described, the loading of the West Lexington to Haefling line is 99.2% and the loading of the West Lexington to Viley Road line is 100.4%. After the reactors are installed, the expected flow on West Lexington to Viley Road is reduced to approximately 93% of capacity and 92% of capacity on West Lexington to Haefling during a high load, summer peak scenario in our 2026 transmission planning model.

While the reactors are expected to be a long term solution, if there were changes to load or topology of the transmission system that would require the reconductoring of both lines in the future, installation of the reactors is still the least cost solution if reconductoring is required beyond 2021.

The figure below shows the Lexington area and the transmission lines. The two lines follow the
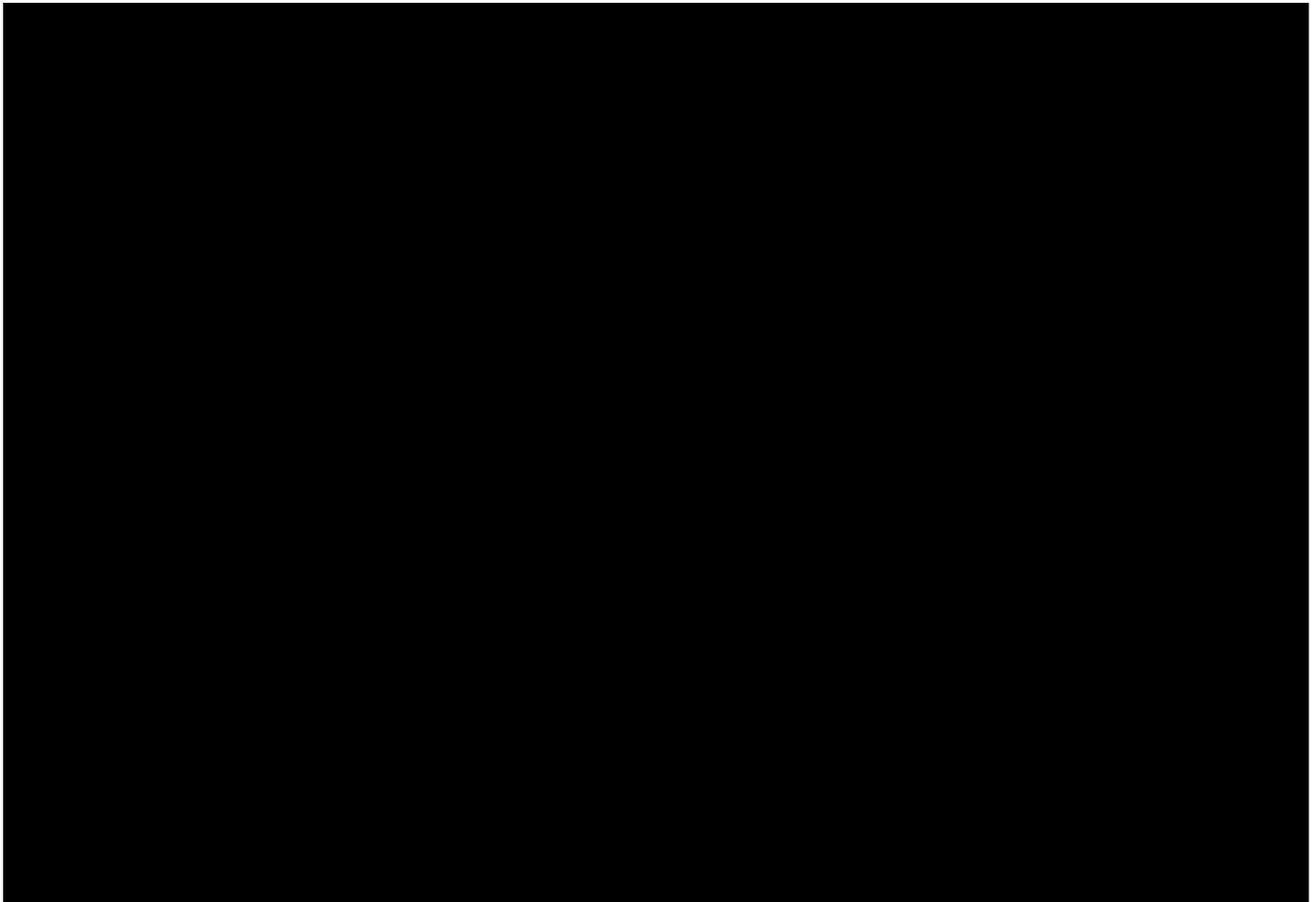
- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $1,546k
       Purchase and install reactors at the West Lexington substation on the West Lexington to Viley Road and West Lexington to Haefling lines in order to comply with the Companies' Transmission Planning Guideline requirements and the North American Electric Reliability Corporation (NERC) TPL-001-4 Reliability Standard.

2. Alternative #1:   NPVRR: ($000s) $12,362k
   Reconductor both the West Lexington to Viley Road ($4,300k) and West Lexington
   to Haefling ($6,100k) 138kV lines.

3. Do Nothing: NPVRR: ($000s) N/A
   This alternative violates the Companies' Transmission Planning Guidelines and the
   North American Electric Reliability Corporation (NERC) TPL-001-4 Reliability
   Standard.

Project Description

- **Project Scope and Timeline**

Milestone Schedule	Date
Project Approved	August, 2016
Materials Ordered	December, 2016
Materials Received	May, 2017
Below Grade Work Begins	March, 2017
Below Grade Work Completed	May, 2017
Above Grade Work Begins	May, 2017
Above Grade Work Completed	May, 2017
Project Complete	May, 2017

- **Project Cost**
  The total cost of this project will be $1,283k and was approved by the 2016 7+5 RAC.
  $3,000k of funding was included in the 2016 BP under project 149705 and 149706. The
  variance between the estimated costs versus the budgeted amount in the 2016 BP can be
  attributed to further developing the scope and determining that a bypass switch is not
  required on either reactor. The estimated total project figure includes a 10% contingency.
  This contingency is reasonable based on the level of detailed engineering and is expected to
  cover uncertainty with the contract labor costs based upon variances that have been observed
  on past similar projects.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids
  for any other necessary materials, as well as the below and above grade construction, will be
  sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	323	855	-	-	1,178
2. Cost of Removal Proposed	-	105	-	-	105
3. Total Capital and Removal Proposed (1+2)	323	961	-	-	1,283
4. Capital Investment 2016 BP	-	499	2,501	-	3,000
5. Cost of Removal 2016 BP	-	-	-	-	-
6. Total Capital and Removal 2016 BP (4+5)	-	499	2,501	-	3,000
7. Capital Investment variance to BP (4-1)	(323)	(356)	2,501	-	1,822
8. Cost of Removal variance to BP (5-2)	-	(105)	-	-	(105)
9. Total Capital and Removal variance to BP (6-3)	(323)	(461)	2,501	-	1,717

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2016 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Financial Summary ($000s):

Discount Rate: 6.5%

Capital Breakdown:
- Labor: $109k
- Contract Labor: $510k
- Materials: $375k
- Other: $0k
- Local Engineering: $74k
- Burdens: $98k
- Contingency: $117k
- Reimbursements: ($0k)
- Net Capital Expenditure: $1,283k

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	$ -	$ 40	$ 65	$ 62	$ 59	$ 1,435
Project ROE	0.0%	4.6%	7.9%	10.0%	10.0%	9.7%

- **Assumptions**
  - The cost for installation of the reactors does not include a transfer bus and that the existing transfer bus can be removed.
  - Outages are obtainable with no extra costs for overtime or temporary configurations. The schedule for the reactor installation assumes the transfer bus will be removed first to allow below grade work to be completed. Line outages are required to install the above grade equipment.
  - No obstructions or rock below grade will cause a cost increase.

- ▪ The protection and control costs for relay settings are included, but it is assumed Although existing carrier and protection equipment can be used.
- ▪ Assumes installation of reactors is a long term solution and reactor removal costs are not required.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  There is a risk that we will not be able to get the required outage(s).

Conclusion and Recommendation Arbough

It is recommended that the Investment Committee approve the West Lexington Reactor Additions project for $1,283k to reliably serve customers and to comply with the Companies' Transmission Planning Guideline requirements and the North American Electric Reliability Corporation (NERC) TPL-001-4 Reliability Standard.

Approval Confirmation for Capital Projects Greater Than or Equal to $1 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake	Victor A. Staffieri
Chief Financial Officer	Chairman, CEO and President

Investment Proposal Project LI-158437 TEP-CR-Eastwood-Simpsonville   **Arbough**

Investment Proposal

Project Name: TEP-CR-Eastwood-Simpsonville

Total Expenditures: $2,466k
Total Contingency: $233k (10%)

Project Number(s): Transmission Lines – LI-158437
                    Distribution Operations - 158353

Business Unit/Line of Business: Transmission

Prepared/Presented By: Delyn Kilpack

Executive Summary

The Eastwood – Simpsonville 69 kV line overloads during planning studies and was identified through the 2018 Transmission Expansion Plan (TEP). This project will provide a facility rating increase for 1.86 miles of the Eastwood – Simpsonville 69 kV line and eliminate the overloads currently identified. The 2018 TEP identified a need date of 11/30/2019.

Transmission Lines plans to replace a 1.86 mile section of 336.4 ACSR 26/7 between the Eastwood and Simpsonville substations on the Eastwood-Shelbyville 69kV line with 556.5 ACSR 26/7, and the existing static wire will be replaced with new optical ground wire (OPGW). In addition to the conductor and static being replaced, thirty-seven (37) existing wood structures will be replaced with new steel structures. Electric Distribution Operations (EDO) will provide the layout work and transferring of distribution underbuild where needed.

The total project cost is $2,466k ($2,118k Transmission Lines, $348k Distribution Operations). This project was included in the 2019 Business Plan under project LI-000086 for $1,395k, with estimated spend of $50k in 2018 and 1,345k in 2019. As scope, timing, and certainty of work has evolved, the estimates have been further refined. The current total project cost is $2,466k, with estimated spend of $30k in 2018, and $2,436k in 2019. Incremental Transmission Lines funding of $743k in 2019 was funded by a reduction in project K9-2019. Funding for the Distribution Operations work in 2019 will be identified through the EDO RAC process in 2019.

Background   **Arbough**

The overload of the Eastwood-Shelbyville 69 kV line was identified in the TEP and approved by TranServ, the Company's Independent Transmission Organization (ITO).

The Eastwood – Simpsonville 69 kV line currently consists of 1.86 miles of 336.4 MCM 26X7 ACSR (aluminum conductor steel reinforced). To eliminate the overload, this line section will be replaced with 556.5 MCM 26X7 ACSR conductor.

During the 90/10 winter peak conditions, an outage of the Blue Lick 345/161 kV transformer or an outage of the Middletown – Mid-Valley Simpsonville 69 kV line results in an overload of 105% in the 2019 winter. This overload exists throughout the planning horizon.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $2,885
       The recommendation is to replace 1.86 miles containing 336.4 ACSR 26/7 conductor with new 556.5 ACSR 26/7 conductor, existing static with OPGW, and thirty-seven (37) wood structures will be replaced with new steel structures.
    2. Alternative #1: Do Nothing   NPVRR: ($000s) N/A
       This alternative puts customer load at risk and violates the Company's Planning Guidelines.
    3. Alternative #2:   NPVRR: ($000s) $20,323
       This alternative is to build a new 69 kV line from the LG&E Middletown 69 kV substation to the KU Finchville 69 kV substation, approximately 12.3 miles. This project would require purchase of new or expansion of existing 69 kV ROW, all new 69 kV structures, and 795 ACSR MCM conductor or an equivalent. Expansion of both the Middletown & Finchville 69 kV substations to accommodate the additional 69 kV line exits, breakers, and all other associated terminal equipment would also be necessary.

Project Description   **Arbough**

TEP-CR-Eastwood-Simpsonville Facility Map

- **Project Scope and Timeline**
  The scope of work will involve the upgrade of 1.86 miles of existing conductor with ACSR, existing static wire with new OPGW, and the replacement of thirty-seven (37) existing wood structures with new steel structures on a section of the Eastwood-Shelbyville 69 kV line. Construction is scheduled to begin in January of 2019 and be completed in August of 2019.

Transmission Lines Project Scope and Timeline – Project LI-158437

Design Start	March 2018
Design Complete	June 2018
Space reserved for steel pole production with manufacturer	July 2018
Materials Delivered	January 2019
Construction Start	January 2019
Facility In-Service	June 2019
Permit Close Out / Project Completion	August 2019

Distribution Operations Project Scope and Timeline – Project 158353 **Arbough**

Design Start	July 2018
Design Complete	December 2018
Materials Ordered	January 2019
Materials Delivered	February 2019
Construction Start	March 2019
Construction Finish	June 2019

- **Project Cost**

	Transmission Lines	Distribution Operations	Total
Total 2018	$30k	$0k	$30k
Total 2019	$2,088k	$348k	$2,436k
Project Total	$2,118k	$348k	$2,466k
Contingency	10%	13%	

Economic Analysis and Risks

- **Bid Summary**

Transmission Lines
Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $565k. The project will utilize standard steel structures, and material. The conductor will be competitively bid through normal Supply Chain processes. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four current contractors which have been awarded Transmission Overhead Construction Maintenance contracts.

Distribution Operations:
Distribution Operations line relocation will be performed by company labor (no bids required).

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	At Post through 2020	Total
1. Capital Investment Proposed	30	2,282	-	-	2,311
2. Cost of Removal Proposed		155	-	-	155
3. Total Capital and Removal Proposed (1+2)	30	2,437	-	-	2,466
4. Capital Investment 2019 BP	50	1,345	-	-	1,395
5. Cost of Removal 2019 BP	-	-	-	-	-
6. Total Capital and Removal 2019 BP (4+5)	50	1,345	-	-	1,395
7. Capital Investment variance to BP (4-1)	20	(936)	-	-	(916)
8. Cost of Removal variance to BP (5-2)	-	(155)	-	-	(155)
9. Total Capital and Removal variance to BP (6-3)	20	(1,091)	-	-	(1,071)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2019 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Included in 2019 BP under project LI-000086

Discount Rate: 6.59%
Capital Breakdown:

	LI-158437 Trans Lines	158353 Dist Ops	Total
Labor	$48k	$155k	$203k
Contract Labor	$914k	$0k	$914k
Materials	$565k	$30k	$595k
Local Engineering	$293k	$15k	$308k
Burdens	$106k	$107k	$213k
Contingency	$192k	$41k	$233k
Reimbursements	$0k	$0k	$0k
Net Capital Expenditure	$2,118k	$348k	$2,466k

- **Assumptions**

  Recommendation - This assumes that the 1.86 miles of existing conductor will be replaced with new ACSR, the existing static wire will be replaced with new OPGW, and thirty-seven (37) existing wood structures will be replaced with new steel structures. An outage must be obtained to complete the project and is scheduled for 2019.

  Alternative #1 – Do Nothing - This alternative puts the customer load at risk and violates the Company's Transmission Planning Guidelines.

  Alternative #2 – Build a new 69 kV line from the LG&E Middletown 69 kV substation to the KU Finchville 69 kV substation, approximately 12.3 miles. This project would require purchase of new or expansion of existing 69 kV ROW, all new 69 kV structures, and 795 ACSR MCM conductor or an equivalent. Expansion of both the Middletown & Finchville 69 kV substations to accommodate the additional 69 kV line exits, breakers, and all other associated terminal equipment would also be necessary.

- **Environmental**

  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Risks**

  Without the recommended re-conductor of the Eastwood – Simpsonville 69 kV line, there is risk of losing load in the Simpsonville area.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the TEP-CR-Eastwood-Simpsonville project for $2,466k to maintain system integrity, reliability, and to prevent failures and unplanned outages.

Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

DocuSigned by:		DocuSigned by:	
kent Blake	11/2/2018 | 8:42 AM EDT	*Paul Thompson*	11/8/2018 | 6:27 AM EST
C055E669F1EB443...		57E11AF682314EE...	
Kent W. Blake	Date	Paul W. Thompson	Date
Chief Financial Officer		Chairman, CEO and President	

Investment Proposal Project 140440 TEP-CR-North Tap-South Park   **Arbough**

Investment Proposal for Investment Committee Meeting on: August 29, 2018

Project Name: TEP-CR-North Tap-South Park

Total Expenditures: $3,324k
Total Contingency: $326k (11%)

Project Number(s): Transmission Lines - 140440
                       Distribution Operations – 158292

Business Unit/Line of Business: Transmission Lines

Prepared/Presented By: Delyn Kilpack

Executive Summary

The North Tap-South Park 69k line overloads during planning studies and was identified through the Transmission Expansion Plan (TEP) back in 2014. This project will provide a facility rating increase for 1.99 miles of the North Tap-South Park 69kV line and eliminate the overloads currently identified. The 2017 and 2018 TEPs showed a need date of summer 2019, however recently completed analysis in the 2019 TEP indicates an upgrade of this line is needed now.

Recent Transmission Expansion Plans have also identified this line as overloaded after a contingency (outage) situation during summer peak conditions, using both the average summer and extreme summer conditions. This line segment has an existing rating of 100 MVA, an upgrade of the existing conductor from North Tap to South Park is required to eliminate the overload condition on the line. After the project is complete, the new line rating for summer emergency conditions will be 127 MVA.

Transmission Lines plans to replace the 1.99 mile 69kV line between the North Tap and South Park substations with aluminum conductor steel-reinforced (ACSR) conductor. In addition to the conductor being replaced, thirty-nine existing wood structures will be replaced with new steel structures. Distribution Operations will provide the layout work and transferring of distribution underbuilt where needed.

The total project cost is $3,324k ($3,009k Transmission Lines, $315k Distribution Operations). This project was included in the 2018 Business Plan (BP) for $3,167k, with estimated spend of $158k in 2018 and $3,009k in 2019. As scope, timing, and certainty of work has evolved, the estimates have been further refined.

The current total project cost is $3,324k, with estimated spend of $172k in 2018, and $3,152k in 2019. The 2018 spend was approved by the RAC in the 7+5 forecast. The 2019 spend is consistent with the proposed 2019 BP.

Background
The overload of North Tap to South Park 69 kV line was identified in the TEP process and approved by the Company and TranServ, the Company's Independent Transmission Organization (ITO).

The North Tap to South Park 69kV line currently consists of 1.78 miles of 795 MCM 61-AAC (All Aluminum Conductor) and 0.21 miles of 840.2 MCM 24X13 ACAR (Aluminum Conductor Alloy Reinforced).   To eliminate the overload, 1.99 miles of line will be replaced with new ACSR.

During peak summer conditions, an outage of the Mud Lane 138/69kV transformer which includes outage of the Mud Lane 138kV bus, shows an overload at 101%. In the 2027 summer models, the overload is 108%.
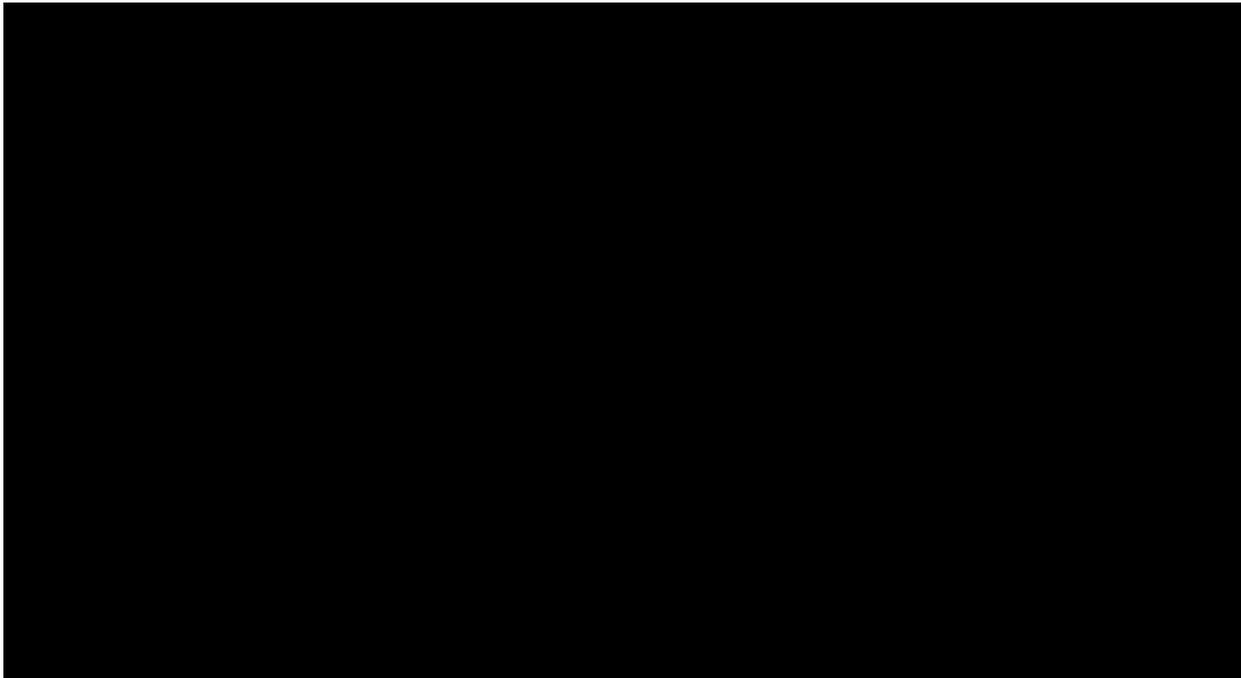
The diagram above shows the location of the overloaded section of South Park to the North Tap section of 69 kV and also shows the location of the contingency.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $3,884
       The recommendation is to replace 1.99 miles containing 795 AAC conductor with new ACSR conductor, and thirty nine (39) wood structures will be replaced with new steel structures.
    2. Alternative #1 – Do Nothing   NPVRR: ($000s) N/A
       This alternative puts customer load at risk and violates the Company's Planning Guidelines.

3. Alternative #2 – Add Second Transformer   NPVRR: ($000s) $11,651 **Arbough**
   Add a second 2nd 138/69kV transformer at Mud Lane and rebuild the 138kV Mud
   Lane bus making it a breaker and a half scheme with eight 138kV breakers.

Project Description
TEP-CR-North Tap-South Park Facility Map
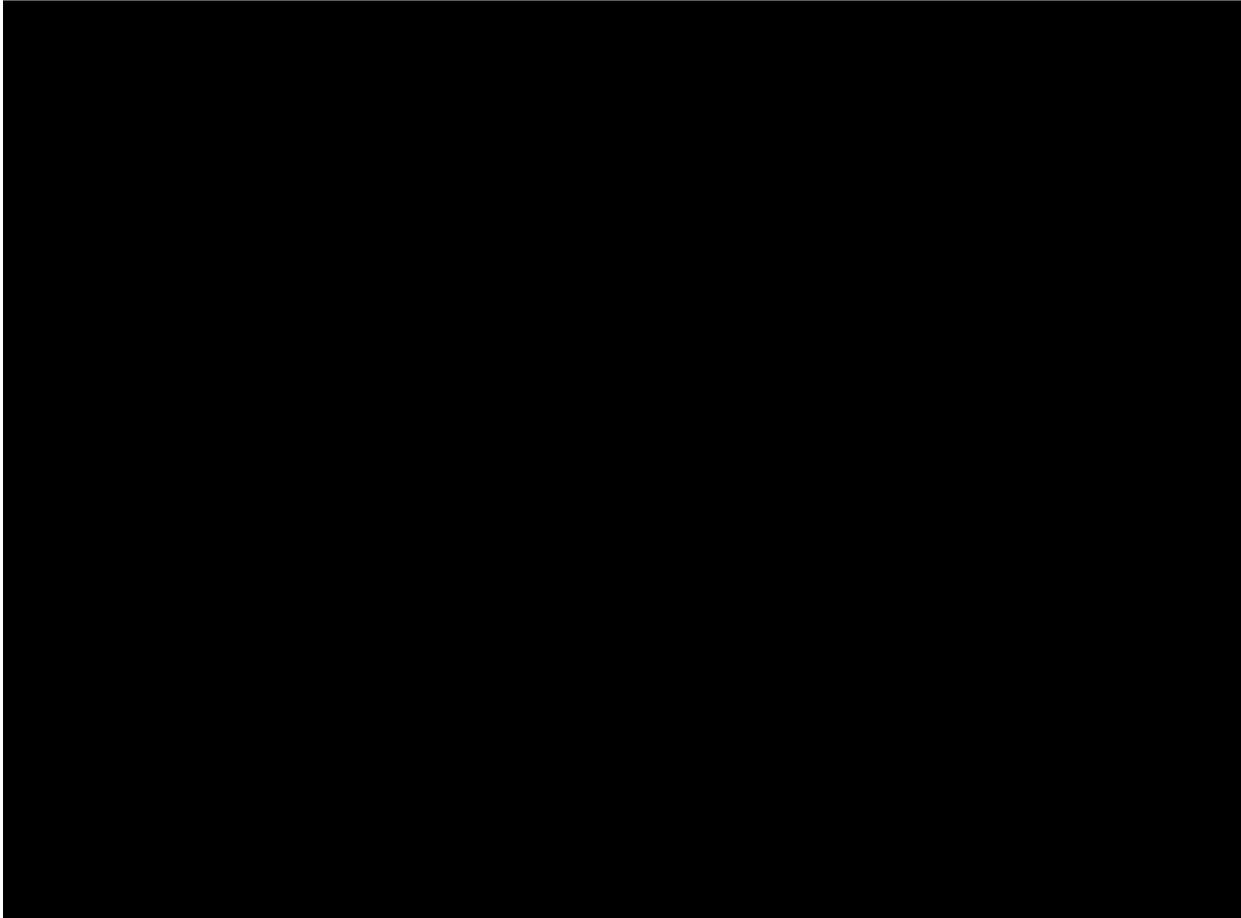
- **Project Scope and Timeline**

The scope of work will involve the upgrade of 1.99 miles of existing conductor with ACSR, and
the replacement of thirty-nine (39) existing wood structures with new steel structures on a
section of the South Park-Mud Lane 69kV line. The line construction will be based on
continuing contracts from the Company's line contractors. B&B Electric, Davis H. Elliot,
William E. Groves and Pike Electric are the four contractors awarded the Transmission
Overhead Construction and Maintenance contract from the October 2011 Investment Committee
meeting. A two-year optional contract extension was approved by the IC in April of 2017.
Construction is scheduled to begin in January of 2019 and be completed in May of 2019.

Transmission Lines Project Scope and Timeline – Project 140440

Design Start	March 2018	**Arbough**
Design Complete	June 2018	
Space reserved for steel pole production with manufacturer	July 2018	
Materials Delivered	January 2019	
Construction Start	January 2019	
Facility In-Service	March 2019	
Permit Close Out / Project Completion	May 2019	

Distribution Operations Project Scope and Timeline – Project 158292

Design Start	July 2018
Design Complete	December 2018
Materials Ordered	January 2019
Materials Delivered	February 2019
Construction Start	March 2019
Construction Finish	June 2019

- **Project Cost**

	Transmission Lines	Distribution Operations	Total
Total 2018	$172k	$0k	$172k
Total 2019	$2,837k	$315k	$3,152k
Project Total	$3,009	$315k	$3,324k
Contingency	10%	20%	

Economic Analysis and Risks

- **Bid Summary**
  Transmission Lines
  Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $317k. The project will utilize conductor, custom steel structures, standard steel structures, and material. The conductor will be competitively bid through normal Supply Chain processes. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors which have been awarded the Transmission Overhead Construction Maintenance contracts.

  Distribution Operations:
  Distribution Operations line relocation will be performed by company labor (no bids required).

- **Budget Comparison and Financial Summary**   **Arbough**

Financial Detail by Year - Capital ($000s)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	172	2,597	-	-	2,769
2. Cost of Removal Proposed	-	555	-	-	555
3. Total Capital and Removal Proposed (1+2)	172	3,152	-	-	3,324
4. Capital Investment 2018 BP	158	2,473	-	-	2,631
5. Cost of Removal 2018 BP		536	-	-	536
6. Total Capital and Removal 2018 BP (4+5)	158	3,009	-	-	3,167
7. Capital Investment variance to BP (4-1)	(14)	(124)	-	-	(137)
8. Cost of Removal variance to BP (5-2)	-	(20)	-	-	(20)
9. Total Capital and Removal variance to BP (6-3)	(14)	(143)	-	-	(157)

Financial Detail by Year - O&M ($000s)	2018	2019	2020	Post 2020	Total
1. Project O&M Proposed	-	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

Discount Rate: 6.59%
Capital Breakdown:

	154585 Trans Lines	156512 Dist Ops	Total
Labor	$112k	$0k	$112k
Contract Labor	$1,754k	$195k	$1,949k
Materials	$317k	$45k	$362k
Local Engineering	$415k	$19k	$434k
Burdens	$138k	$3k	$141k
Contingency	$273k	$53k	$326k
Reimbursements	$0k	$0k	$0k
Net Capital Expenditure	$3,009k	$315k	$3,324k

- **Assumptions**

   Recommendation - This assumes that the 1.99 miles of existing conductor will be replaced with ACSR, and thirty-nine (39) existing wood structures will be replaced with new steel structures. An outage must be obtained to complete the project and is scheduled for 2019.

   Alternative #1 – Do Nothing - This alternative puts the customer load at risk and violates the Company's Transmission Planning Guidelines.

   Alternative #2 – This alternative assumes that a second 138/69kV transformer at Mud Lane would be added, and rebuild the 138kV Mud Lane bus would be completed, making it a breaker and a half scheme with eight 138kV breakers.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

- **Risks**
  - Without the proposed replacement of the existing wire in a section of the South Park-Mud Lane 69kV line, there is a risk of losing load at South Park and EKPC Brooks substation.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the TEP-CR-North Tap-South Park
project for $3,324k to improve reliability of the electric transmission system.

Approval Confirmation for Capital Projects Greater Than $2 million:

The Capital project spending included in this Investment Proposal has been approved by the
members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the
signatures below are also required for approval of this Capital project spending request.

Kent W. Blake   Date   Paul W. Thompson   Date
Chief Financial Officer   Chairman, CEO and President

Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: April 25, 2018

Project Name: Trimble County Substation 345 kV Reactors

Total Expenditures: $2,858k (Including $260k of contingency)

Project Number(s): 156518

Business Unit/Line of Business: Transmission

Prepared/Presented By: Chris Balmer – Director, Transmission Strategy & Planning

Executive Summary
The Trimble County Substation 345 kV reactor project is a Transmission Expansion Plan (TEP) project to prevent the overload of the Trimble County – Clifty Creek 345 kV line. The LG&E/KU Planning Guidelines require a project to mitigate this overload and the installation of reactors is the least cost solution.

According to analysis performed as part of the 2018 TEP, the overload of the Trimble County – Clifty Creek line was identified during contingency of the 765 kV Jefferson – Rockport line, under summer peak conditions in 2021. In addition, the post contingent overload of the Trimble County – Clifty Creek 345 kV line has historically occurred during real-time operations and resulted in either generation redispatch and/or curtailment of firm and non-firm transmission service to mitigate the risk.

The Trimble County – Clifty Creek 345 kV line is approximately 12.5 miles long, crosses the Ohio River, and connects LG&E/KU's Trimble County generation plant with OVEC's Clifty Creek generation plant. It is a major transmission line interconnecting LG&E/KU and PJM with a summer emergency rating of 1,451 MVA. The Trimble County reactor project will raise impedence of this line, such that power flow will be diverted to other transmission lines with available capacity while maintaining the post contingent flow of the Trimble County – Clifty Creek 345 kV line below the summer line rating.

The total cost of this project is $2,858k with $491k in 2018 and $2,367k in 2019. This project was included in the 2018 BP under project SU-000098 with $2,322k in 2021. The project is being accelerated, by about one year, due to benefits of eliminating or minimizing operational issues that result in Transmission Loading Relief (TLRs) and generation redispatch and increasing the probability that the project will be completed by the need date.

Background

The overload of the Trimble County – Clifty Creek 345 kV line was identified in the 2018 Transmission Expansion Planning (TEP) process. The Company is awaiting final approval from TranServ, the Independent Transmission Organization (ITO), which is expected to occur in the next couple of months and is not expected to impact this recommendation.

Table 1 below shows the flows on the overloaded line for various scenarios summer peak conditions.

Table 1: Scenarios and Flows on Trimble County – Clifty Creek during Contingency

Scenario	Flow (MVA)	Percent of Overload	Flow with Reactor	Percent of Loading with Reactor
2021 Summer Peak				
2023 Summer Peak				
2028 Summer Peak				
2028 Summer Peak; Clifty Creek Retired Sensitivity				

██████   In addition, there have been operational issues in the past which have caused TLRs and generation redispatch. The proposed project is expected to eliminate or greatly reduce TLRs and generation redispatch for the overload of the Trimble County – Clifty Creek line in the future.

Since Clifty Creek generation output has a material impact on power flow in the area, a sensitivity scenario was conducted to evaluate whether installing reactors is expected to also eliminate an overload from the potential retirement of Clifty Creek units. As can be seen by the table above, and assuming all things are equal, the reactor project will be sufficient to eliminate an overload associated with lower output or complete retirement of the Clifty Creek generation site.

Further analysis indicates that approximately 5,000 MWs of non-firm transfers from MISO to PJM can be accommodated with the reactor project and not require reconductoring the Trimble County – Clifty Creek line. This analysis assumed Clifty Creek generation is still operational.

Figure 1 on the next page shows a geographic map of the Trimble – Clifty Creek 345 kV and the Rockport – Jefferson 765 kV line.

Figure 1: Geographic Map of Area

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $3,154
     Add 345 kV reactors at the Trimble County substation on the Clifty Creek line.

  2. Alternative #1: NPVRR: ($000s) $19,111
     Reconductor the Trimble County – Clifty Creek 345 kV line. This alternative is higher cost and more difficult to complete due to the length of project time and outages required. A comparable project is to reconductor the line energized at a higher cost. The additional transmission capacity that would be gained by this alternative is not needed.

  3. Do Nothing: NPVRR: ($000s) N/A
     This alternative is not a viable option since it doesn't comply with the ITO approved LG&E/KU Planning Guidelines.

Project Description

- **Project Scope and Timeline**

Description	Date
Project Approved for Preliminary Engineering	10/11/2016
Project Approved for Full Funding	5/1/18
Materials Ordered	5/8/18
Engineering Complete	10/3/18
Materials Received	1/15/19
Construction Begins	3/1/19
Construction Completed	6/5/19
Project Complete	10/28/19

- **Project Cost**
  The total cost of this project is $2,858k with $491k in 2018 and $2,367k in 2019. This project was included in the 2018 BP under project SU-000098 with $2,322k in 2021. The estimated total project figure includes a 10% contingency based on the level of detailed engineering performed.

Economic Analysis and Risks

- **Bid Summary**
  Previously established blanket contract agreements will be utilized for related materials. Bids for any other necessary materials, as well as the below and above grade construction, will be sent out soon after project approval.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2018	2019	Post 2019	Total
1. Capital Investment Proposed	491	2,367	-	2,858
2. Cost of Removal Proposed	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	491	2,367	-	2,858
4. Capital Investment 2018 BP	-	-	2,322	2,322
5. Cost of Removal 2018 BP	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	-	-	2,322	2,322
7. Capital Investment variance to BP (4-1)	(491)	(2,367)	2,322	(536)
8. Cost of Removal variance to BP (5-2)	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(491)	(2,367)	2,322	(536)

Financial Detail by Year - O&M ($000s)	2018	2019	Post 2019	Total
1. Project O&M Proposed	-	-	-	-
2. Project O&M 2018 BP	-	-	-	-
3. Total Project O&M variance to BP (2-1)	-	-	-	-

The Post 2019 BP amount was included in the budgeted project SU-000098. The 2018 capital spending was approved in the 3+9 RAC forecast.

Financial Summary ($000s):

Discount Rate:	6.58%
Capital Breakdown:	
Labor:	$84k
Contract Labor:	$782k
Materials:	$1,140k
Other:	$0k
Local Engineering:	$423k
Burdens:	$169k
Contingency:	$260k
Reimbursements:	$0k
Net Capital Expenditure:	$2,858k

- **Assumptions**
  - TEP planning models developed by other industry participants and approved by the ITO are assumed to be an accurate reflection of future transmission system conditions. Specifically, the PJM/ MISO 345 kV projects of Coleman – Rockport – Duff are assumed to be operational and in service no sooner than 2021.
  - The ITO will approve this project as part of their overall review and approval of the 2018 TEP. Approval is expected within the next couple of months.
  - Outages required to perform the work will be granted at the time and duration necessary to maintain the estimated schedule.

- **Environmental**
  This project does not require permitting and there are no known issues regarding air, water, waste, lead, or asbestos.

- **Risks**
  - Outage of the Trimble County – Clifty Creek 345kV line presents challenges due to the criticality of the line. This risk is being mitigated by accelerating the project to account for the possibility that system conditions will not be conducisive to an outage in the spring of 2019. If this were to be the case, an outage window in the fall of 2019 will be pursued.

  - ITO will not approve the project as part of the 2018 TEP approval process. This is a low risk situation and can be mitigated. The Company has the right to construct facilities without ITO approval; however, this is not the preferred course. If the ITO does not approve the 2018 TEP prior to ordering material, Company will assess the project and coordinate with the ITO.

  - The project will not eliminate the overload as expected. If future conditions are different than planned, then future analysis will be performed via the annual TEP process or other study process and mitigations will be recommended based on that analysis.

Conclusions and Recommendation   Arbough

It is recommended that the Investment Committee approve the Trimble County Reactors project for $2,858k to relieve overloading of the Trimble County – Clifty Creek 345 kV line in order to reliably serve customers and meet the LG&E/KU Planning Guidelines in a least cost manner.

<u>Approval Confirmation for Capital Projects Greater Than or Equal to $2 million</u>:

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

Kent W. Blake Date	Paul Thompson Date
Chief Financial Officer	Chairman, CEO and President

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 34

Responding Witness: Daniel K. Arbough

Q-34.   Reference the Companies' response to AG DR 1-74.

    a. Does the Company's response to subpart (b) to AG DR 1-74 indicate that the Company does not have the forecasted expense for outages in 2023 and 2024, or merely that the Company chose not to provide the information?

    b. If the response to subpart (a), above, indicates that the Companies have the information available to provide the forecasted outage expense for years 2023 and 2024, provide same.

    c. Provide the total expected expense for 2018 for the attachment, using YTD actual data and forecasted data for 2018 not yet expended. Further, provide the actuals for 2018 upon the Companies' receipt of same.

A-34.

    a. The Company did not provide the forecasted outage expense for 2023 and 2024 since these years are outside of the eight-year cycle used to calculate the eight-year average outage expense. See the response to part b for forecasted 2023 outage expense. 2024 information has not been reviewed or approved by management.

    b. See attached for 2023 forecasted outage expense. 2024 information has not been reviewed or approved by management.

    c. See attached.

| LG&E Outage - Not normalized | | 2023 | |
Unit	FERC	Plan	
0311 - TRIMBLE COUNTY 1 - GENERATION	510	$	262,500
	512		2,432,068
	513		1,115,282
0321 - TRIMBLE COUNTY 2 - GENERATION	512		77,005
0211 - MILL CREEK 1 - GENERATION	512		2,350,000
	513		1,850,000
0221 - MILL CREEK 2 - GENERATION	512		525,001
	513		349,999
0231 - MILL CREEK 3 - GENERATION	510		425,000
	512		1,650,000
	513		2,550,000
0241 - MILL CREEK 4 - GENERATION	512		550,001
	513		325,001
0212 - MILL CREEK-SO2 UNIT 1	512		474,999
0222 - MILL CREEK-SO2 UNIT 2	512		174,999
0232 - MILL CREEK-SO2 UNIT 3	512		475,001
0242 - MILL CREEK-SO2 UNIT 4	512		180,001
0172 - CANE RUN CC GT 2016	554		405,101
0432 - PADDYS RUN GT 13	553		139,533
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	553		5,519
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	553		6,099
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553		133,581
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	553		98,431
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	553		5,931
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	553		4,821
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	553		9,984
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	553		10,168
Total		$	**16,586,025**

| LG&E Outage - Not normalized | | 2018 |
Unit	FERC	Forecast[1]
0311 - TRIMBLE COUNTY 1 - GENERATION	511	$ 2,184
	512	669,032
	513	375,964
0321 - TRIMBLE COUNTY 2 - GENERATION	511	13,537
	512	813,467
	513	524,436
0211 - MILL CREEK 1 - GENERATION	512	597,375
	513	106,597
	514	1,181
0221 - MILL CREEK 2 - GENERATION	512	2,139,215
	513	2,288,343
	514	4,862
0231 - MILL CREEK 3 - GENERATION	511	69,690
	512	2,459,145
	513	480,873
0241 - MILL CREEK 4 - GENERATION	510	518,297
	511	31,304
	512	4,121,193
	513	2,256,719
	514	1,367
0172 - CANE RUN CC GT 2016	549	103
	552	50,082
	553	167,429
	554	88,012
0432 - PADDYS RUN GT 13	553	133,892
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	553	4,715
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	553	20,610
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553	57,267
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	553	16,222
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	553	24,093
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	553	22,487
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	554	17,672
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	553	11,400
Total		**$ 18,088,762**

(1) The forecast includes YTD November Actuals and December Forecast

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 35

Responding Witness: Daniel K. Arbough / Christopher M. Garrett

Q-35.   Reference the Companies' response to AG DR 1-77.

    a. Provide the estimated amounts for the last two months of 2018 where the Company has provided YTD amounts for 2018.

    b. Provide actual amounts for 2018 where the Company provided YTD 2018 amounts, upon the Companies' receipt of same.

A-35.

    a. Forecast amounts for November and December 2018 are in the table below.

Forecast	November 2018	December 2018
Distribution	$ 724,429	$ 694,902
Transmission	$ 400,814	$ 388,143
Total	**$ 1,125,243**	**$ 1,083,045**

    b. Actuals through November 2018 are in the table below.

	YTD 11/30/18
Distribution	$ 7,414,408
Transmission	$ 3,078,748
Total	**$10,493,156**

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 36

Responding Witness: Daniel K. Arbough / John K. Wolfe

Q-36. Refer to the Companies' response to AG DR 1-77(b), Attachment, Distribution notes a and b, which states:

"a. Variances for both companies are due to changes from original budget estimates in order to address hazard trees as appropriate.

b. Variances for both companies are due to changes from original budget estimates in order to maintain the appropriate trimming cycles and to address hazard trees as appropriate."

a. Provide the original budget estimate.

b. Explain why the budget was changed from the original budget estimate.

c. Do actual expenses include storm costs? If so, provide the storm costs included in the actual for each year.

A-36.

a. Original budget estimate was provided in the Companies' response to AG 1-77 in Budget column.

b. Original budget estimate was not changed. Actuals were different than the budget, thus resulting in the variance.

c. No.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 37

Responding Witness: Daniel K. Arbough / Christopher M. Garrett

Q-37. Reference the Companies' response and attachments to KIUC DR 1-54 (LG&E) and KIUC DR 1-62 (KU). Explain the significant increases from the December 31, 2017, actual deferrals to the April 30, 2020, forecasted deferrals.

A-37. The increase from the actual deferral balance as of December 31, 2017 to the forecasted deferral balance as of April 30, 2020 for LG&E is due to the following changes in outages included as part of the eight-year planned outage cycle and inclusion of amortization of the regulatory asset through the period ending April 30, 2020:

Generating Unit	Amount
0231 - MILL CREEK 3 - GENERATION	$ 5,744,315
0221 - MILL CREEK 2 - GENERATION	$ 2,474,047
0172 - CANE RUN CC GT 2016	$ 1,486,787
0211 - MILL CREEK 1 - GENERATION	$ 1,352,592
0241 - MILL CREEK 4 - GENERATION	$ 1,138,616
All Other	$ 793,010
Regulatory Asset Amortization	$ (914,744)

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 38

Responding Witness: Daniel K. Arbough

Q-38.   Reference the Companies' response to KIUC 1-58.

a.   Explain and support the test year increases for: OTHER-LABOR-3RD PARTY, and OTHER EXPENDITURES.

A-38.
a.   The test year increases in Other-Labor-3rd Party are primarily due to O&M needed for automation of processes, creative work for customer education advertising and a reclassification of expenses from other non-labor to other outside services. The increase in Other Expenditures is primarily due to additional work related to cybersecurity.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 39

Responding Witness: Daniel K. Arbough / Christopher M. Garrett

Q-39. Reference the Companies' response to Staff DR 1-50.

    a. Provide the Company's calculation of test period storm damage expense, including the amounts averaged and the amounts removed assuming regulatory asset approval.

    b. Provide the annual storm damage expense, by company and separated between transmission and distribution, for each year since 2014, including actual or anticipated amounts for 2018.

A-39.
    a. See attached.

    b. See below. 2018 includes actuals through November 30 and forecast for December.

	2014	2015	2016	2017	2018
Distribution	$ 9,069,913	$ 4,844,213	$ 2,304,503	$ 2,267,174	$ 15,535,842
Transmission	$ 295,181	$ 143,350	$ 83,641	$ 99,240	$ 103,917
Total	**$9,365,094**	**$ 4,987,563**	**$ 2,388,144**	**$ 2,366,414**	**$ 15,639,759**

LGE 3 Year Storm Average - Distribution
2019BP

Company	FERC	OPEX ADJUSTED FOR MAJOR WEATHER EVENTS				OPEX ADJUSTED FOR MAJOR WEATHER EVENTS (CPI ADJUSTED)				3 Year Average By FERC (CPI ADJUSTED)	BP Amounts by FERC (CPI ADJUSTED)				
		2015	2016	2017	Grand Total	2015	2016	2017	Grand Total		2019	2020	2021	2022	2023
LGE	580	626,687	274,400	292,266	1,193,353	647,795	280,116	292,266	1,220,177	406,725.65	421,667	433,287	444,908	456,529	466,489
	583	570,382	265,227	283,763	1,119,372	589,593	270,753	283,763	1,144,108	381,369	395,379	406,275	417,172	428,068	437,407
	590	63,558	8,789	63,322	135,670	65,699	8,972	63,322	137,994	45,998	47,688	49,002	50,316	51,630	52,757
	593	3,267,140	1,669,106	1,580,248	6,516,494	3,377,181	1,703,879	1,580,248	6,661,308	2,220,436	2,302,003	2,365,444	2,428,885	2,492,326	2,546,704
	594	144,131	64,544	36,023	244,698	148,986	65,888	36,023	250,897	83,632	86,705	89,094	91,484	93,873	95,921
	595	22,911	2,089	534	25,533	23,682	2,132	534	26,348	8,783	9,105	9,356	9,607	9,858	10,073
	598	136,904	19,454	11,018	167,376	141,515	19,859	11,018	172,392	57,464	59,575	61,217	62,859	64,501	65,908
	925	-	895	-	895	-	914	-	914	305	316	324	333	342	349
	930	12,500	-	-	12,500	12,921	-	-	12,921	4,307	4,465	4,588	4,711	4,834	4,940
LG&E Total		4,844,214	2,304,503	2,267,174	9,415,891	5,007,373	2,352,513	2,267,174	9,627,060	3,209,020	3,326,902	3,418,589	3,510,275	3,601,961	3,680,549

Note: There were no major weather events during this time period
(major considered events where a Regulatory Asset was filed).

HISTORICAL CPI INDEX	
2017	1
2016	1.02083333
2015	1.03368113

CPI ADJUSTMENT TO ESCALATE FOR BP	
2023	1.1469
2022	1.1224
2021	1.0939
2020	1.0653
2019	1.0367
2018	1.0163

LGE 3 Year Storm Average - Distribution
2019BP

Monthly Amounts for Budget Entry

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
LGE Monthly Avg	0.02	0.04	0.06	0.13	0.05	0.18	0.24	0.10	0.06	0.03	0.04	0.04	

2019 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
580	7,155.86	16,080.97	27,070.01	56,504.18	20,545.26	74,151.91	102,158.83	44,130.28	23,901.07	14,158.02	18,329.59	17,480.61	421,666.59
583	6,709.75	15,078.44	25,382.41	52,981.59	19,264.43	69,529.12	95,790.03	41,379.10	22,411.02	13,275.38	17,186.88	16,390.83	395,378.99
590	809.28	1,818.65	3,061.44	6,390.25	2,323.53	8,386.09	11,553.48	4,990.84	2,703.05	1,601.18	2,072.95	1,976.94	47,687.68
593	39,065.97	87,790.77	147,783.23	308,473.10	112,162.69	404,817.29	557,715.36	240,920.30	130,483.01	77,292.85	100,066.66	95,431.84	2,302,003.08
594	1,471.41	3,306.62	5,566.23	11,618.59	4,224.59	15,247.37	21,006.25	9,074.22	4,914.62	2,911.22	3,768.99	3,594.42	86,704.55
595	154.52	347.25	584.55	1,220.15	443.65	1,601.23	2,206.02	952.95	516.12	305.73	395.81	377.48	9,105.46
598	1,011.01	2,271.99	3,824.58	7,983.18	2,902.73	10,476.53	14,433.48	6,234.93	3,376.85	2,000.31	2,589.69	2,469.74	59,575.04
925	5.36	12.04	20.27	42.31	15.38	55.52	76.49	33.04	17.90	10.60	13.72	13.09	315.74
930	75.78	170.29	286.66	598.35	217.56	785.23	1,081.81	467.32	253.10	149.93	194.10	185.11	4,465.22
LGE Total	56,458.95	126,877.03	213,579.38	445,811.69	162,099.83	585,050.30	806,021.74	348,182.98	188,576.74	111,705.22	144,618.40	137,920.07	3,326,902.33
													-

2020 Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
580	7,353.07	16,524.14	27,816.04	58,061.38	21,111.47	76,195.47	104,974.23	45,346.47	24,559.76	14,548.20	18,834.73	17,962.36	433,287.33
583	6,894.66	15,493.99	26,081.92	54,441.71	19,795.34	71,445.28	98,429.91	42,519.47	23,028.65	13,641.24	17,660.54	16,842.55	406,275.26
590	831.58	1,868.77	3,145.81	6,566.35	2,387.57	8,617.20	11,871.88	5,128.38	2,777.54	1,645.30	2,130.08	2,031.42	49,001.90
593	40,142.60	90,210.20	151,856.00	316,974.33	115,253.78	415,973.68	573,085.47	247,559.83	134,079.00	79,422.97	102,824.40	98,061.86	2,365,444.10
594	1,511.96	3,397.75	5,719.63	11,938.78	4,341.01	15,667.58	21,585.17	9,324.30	5,050.06	2,991.45	3,872.86	3,693.48	89,094.04
595	158.78	356.82	600.66	1,253.78	455.88	1,645.36	2,266.81	979.21	530.34	314.15	406.72	387.88	9,356.40
598	1,038.88	2,334.61	3,929.98	8,203.19	2,982.73	10,765.25	14,831.25	6,406.76	3,469.92	2,055.44	2,661.06	2,537.81	61,216.87
925	5.51	12.37	20.83	43.48	15.81	57.05	78.60	33.95	18.39	10.89	14.10	13.45	324.44
930	77.87	174.98	294.56	614.84	223.56	806.87	1,111.62	480.19	260.07	154.06	199.45	190.21	4,588.28
LGE Total	58,014.91	130,373.64	219,465.42	458,097.84	166,567.15	601,173.74	828,234.94	357,778.58	193,773.73	114,783.71	148,603.95	141,721.02	3,418,588.62
													-

Test Year (4/30/19-4/30/20)	3,350,127	
	3,350,132	Schedule B-5.2, page 4, line 13
	(5)	Difference, rounding

Transmission Storm Test Year Expense

| | | 2015 | 2016 | 2017 | Average | 2019 BP | | | | | |
						2019	2020	2021	2022	2023	Total
1	Combined LG&E and KU Storm Expense	731,635	391,193	275,383							
2	Less Standby Crew cost excluded	389,258									
3	sub-total	342,377	391,193	275,383							
4	Annualized Total (Row 3 / 10 x 12)	410,853									
5	Total used in Averaging	410,853	391,193	275,383	359,143						
6	CPI					1.95%	2.83%	2.61%	2.40%	2.44%	
7	CPI Adjusted Total					366,146	376,508	386,335	395,607	405,260	
8	Company split based on Transmission Coordination Agreement					35%	35%	35%	35%	35%	
9	LG&E Storm Expense					128,151	131,778	135,217	138,462	141,841	
10	# of months of storm expense in the test period					8	4				
11	Test Period Storm Expense					85,434	43,926				129,360

Note: There is an $8 rounding difference between the calculation and the office figure from PowerPlan ($129,368).

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 40

Responding Witness: Elizabeth J. McFarland

Q-40. Reference the Companies' response to AG DR 1-76.

    a. Explain, in detail, the Company's calculation of test year METER READING EXPENSE, as provided on Schedule C-2.1 in each matter.

    b. Explain, in detail, why the METER READING EXPENSE is expected to increase so dramatically for LG&E and KU electric operations as compared to LG&E gas operations.

A-40.

    a. Meter Reading contracts will expire on May 31, 2019. Staffing issues signaled changing market conditions and likely increases in costs for these services. Meter Reading Costs for the test year were calculated using anticipated costs per meter read per utility times the number of assigned reads per utility. Company Labor is calculated based on specific employees and their salaries. Other Expenses include miscellaneous items such as materials, office supplies, and fuel adjustments.

	LG&E	KU	KU Jurisdictional
Test Year	$6,156,772	$9,154,025	$8,696,598
Meter Reading Costs	$5,147,230	$8,064,069	$7,661,107
Company Labor	$798,178	$724,508	$688,304
Other Expenses	$211,364	$365,448	$347,187

    b. The contracted cost to read LG&E electric meters and gas meters are the same per meter. The anticipated percentage increase is the same for both. KU has many more meters to read than are read for LG&E's gas operations and the per-meter increase in metering reading cost is larger for KU than for LG&E, which are the main reasons KU's increase is larger. Meters in the KU territory are more widely dispersed and require significantly more time, fuel, and thus costs to read.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 41

Responding Witness: Gregory J. Meiman

Q-41. Reference the Companies' response to AG DR 1-112. Provide the reasoning for relying on such diversity of companies in the peer list of the WTW study (e.g., water utilities, solar companies, cooperatives, ISO New England) rather than those of similar size, operation, and region.

A-41. The referenced compensation surveys available to WTW cover all components of compensation (e.g., base salary and target short-term at-risk compensation) with survey participants primarily consisting of regulated utilities covering the United States, as this scope best aligns with the market for talent. A broader utility survey sample enables greater coverage of benchmark positions, which was critical given 230 positions were being benchmarked. Given limited data availability for utilities in the same geographic footprint or region of KU and LG&E, a more refined market scope was not used.

According to WTW, the surveys are considered some of the most reliable and comprehensive surveys for utility industry compensation data in the country and the survey participants consist primarily of regulated utilities. Neither the Companies nor WTW determine the participants in any given year.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 42

Responding Witness: Gregory J. Meiman

Q-42. Reference the Companies' response to AG DR 1-114. Provide the reasoning for recommending $16 per hour for call center starting pay when that amount is above both the mean and the median of the data provided in response to part a of the referenced data request.

A-42. Understanding some local call centers were paying more than $16, and the starting wage rate was within the Companies' competitive range, the Companies determined an adjustment was appropriate. Advertising a higher starting rate has increased the candidate pool with the goal of improving the retention and reducing the turnover costs. According to the Kentucky Center for Statistics, an agency within the Kentucky Education and Workforce Development Cabinet, in October 2018, Kentucky unemployment rate was 4.5 percent. This low unemployment rate makes it difficult to attract skilled candidates.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 43

Responding Witness: Gregory J. Meiman

Q-43. Reference the Companies' response to AG DR 1-114. The response to subpart (b) to AG DR 1-114 states that call center pay satisfaction survey scores were lower than those for the rest of the company.

    a. Did any other employment groups (similar to a grouping such as call center employees) have pay satisfaction survey scores as low as or lower than the call center employees? If the response is in the affirmative, discuss differences of management and results regarding those groups from the pay-raise approach taken with the call center employees.

    b. Were the call center pay satisfaction scores the only exit interview survey scores that were less than the rest of the company? If the response is in the negative, provide those other survey areas that were low, and discuss how the Companies determined the low satisfaction with pay was separate from and not a result of the other areas of dissatisfaction.

A-43.
    a. No other groups had pay satisfaction scores as low as or lower than the call center employees.

    b. From the time period 2015-2017, the call center had other exit interview scores that were less than the rest of the company in the below categories:

- Ability to balance family and work life
- Communication within your workgroup
- Cooperation with other departments
- Diversity of Workforce
- Hours required to work
- Overall work experience with LG&E and KU
- Manager/Supervisor approachable with work issues
- Manager/Supervisor demonstrated fair and equal treatment
- Manager/Supervisor support
- Opportunity for advancement

- Personal development opportunities
- Stress related to the job
- Teamwork and Support from co-workers
- Training opportunities
- Work Environment
- Would you recommend the company to a friend as a place to work

While the above were lower, only the categories of pay and stress related to the job were rated as dissatisfied. The score related to stress can be attributed to the nature of their job.

HR was consulted on starting wage rates (see response to AG DR1-115) and a recommendation was made to increase pay while staying within the established range for this position.

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 44

Responding Witness: Gregory J. Meiman

Q-44. Reference the Companies' response to AG DR 1-115. The response to the data request was that while the call center employee starting pay was within the competitive range, other factors prompted further assessment determining the pay level was not fair. Explain how the pay can fall within competitive range and not be fair. In other words, is not "competitive range" the criterion of fairness? If the response is in the negative, provide the following:

   a. Explain the Companies' definition of competitive range and how it differs from fairness.

   b. Will the Companies adjust their compensation philosophy to include other factors of fairness?

   c. Will the Companies adjust their studies to include only criteria-based peer companies to better align compensation fairness with employee expectations?

A-44.
   a. The Companies define their competitive range by targeting their base compensation salary range midpoints at the 50th percentile of market. Salary range minimums and maximums are based on 70% and 130% of the established 50th percentile midpoint.

   Regarding Mr. Meiman's reference to "fair", it is explained in his testimony, p. 7, line 17, as it was referencing "fair relative to the pay for other similarly-situated positions within the organization."

   b. No, the Companies will continue to use their current compensation philosophy.

   c. See b above.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 45

Responding Witness: Gregory J. Meiman

Q-45. Reference the Companies' response to AG DR 1-115. Provide the following:

  a. What is the current 50th percentile of national market for call center employees?

  b. What is the current 70% to 130% range based on that 50th percentile?

  c. What is the dollar impact to the revenue requirements of the projected increase to call center employee wages?

  d. Refer to the direct testimony of Gregory J. Meiman, page 6, wherein he explains the example of the Companies' determination that call center employee compensation was below market. Other than the call center employee example, were any other employee groups' compensation determined to be below market whose compensation was adjusted for the projected test period? If the answer is in the affirmative, provide a listing of the employee groups and the dollar impact per group to the revenue requirements of the projected or actual increase.

A-45.

  a. See attachment. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

  b. See attachment. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

  c. The dollar impact to the LG&E revenue requirement is $932,166.

  d. No.

CONFIDENTIAL INFORMATION REDACTED

A-45.

    a. According to the 2017 WTW MMPS compensation survey, the 50th percentile of national market data for entry level call center jobs was ███████ (However the Companies used a local geographical cut when determining the salary range midpoint for our entry level job).

    b. The calculated range based on the national 50th percentile is:

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 46

Responding Witness: Gregory J. Meiman

Q-46. Reference the Companies' response to AG DR 1-115. If relatively low exit interview pay satisfaction scores prompt the Companies to conduct further assessment for fairness, do relatively high exit interview pay satisfaction scores also prompt the Companies to conduct further assessment for fairness? If the response is in the affirmative, provide a recent example. If the response is in the negative, explain why no further assessment for fairness is conducted.

A-46. No. Exit interviews are conducted to identify issues and to better understand why an employee is leaving the organization. A satisfied score for pay does not indicate that pay is too high. The Companies rely on the established market range to determine whether or not compensation level is appropriate.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 47

Responding Witness: Gregory J. Meiman

Q-47. Reference the Companies' response to AG DR 1-117. Subpart (b) to AG DR 1-117
requested individual and team effectiveness criteria for senior managers in Electric
Distribution and Energy Supply and Analysis. The Companies' response stated that
goals vary by individual and department. Provide the following:

    a. The specific measures for a sample of three specific senior managers in each of
the departments specified.

    b. For each specific measure in subpart (a), above, specify to which of the five
broad measures and weightings (provided in the response to subpart (a) to AG
DR 1-117) it applies.

A-47.

    a. The requested specific measures can be found in AG 1-117a. Individual
objectives also can be found in the attachment.

    b. While individual goals are not required to link directly to the five measures, in
most cases they do support those objectives and the respective department
objectives. In the attachment, the links to the five measures have been noted
where applicable.

Electric Distribution-SM1

Objective 1: Management Objective - (All Measures)

Actively support company initiatives for safety, wellness, diversity, affirmative action, performance management, employee development and customer focus, while modeling company values and behaviors.

Objective 2: Safety Performance - (Corporate Safety)

Ensure, without compromise, that safety excellence is the core expectation of business operations, and that management and employees are responsible and accountable for a safe work environment.

Ensure hazard assessment and mitigation plans are completed for all responsibility areas, placing emphasis on performing risk analysis where personnel, work practices, technology, or business processes have changed.

Continue to mentor new employees on safety culture and best work practices; where feasible, assign employees with less than five years of experience a formal mentor that is different than their immediate supervisor.

Continue to place emphasis on critical danger zone (CDZ) tasks. A CDZ is present when there is a hazardous situation, condition or action that can potentially lead to an immediate and serious injury, a major loss of equipment, or significantly impact a process or the environment.

Continue to refine key business processes and leading safety indicators to influence desired safety cultures and behaviors. Continue to focus on initiatives to reduce unintended outages and vehicle incidents.

Objective 3: Operational Performance - (All Measures)

Direct resources under responsibility towards attainment of 2018 performance targets. Support business processes that provide for safe, effective, and timely restoration of services following routine and emergency outage events. Ensure EDO's reliability programs - distribution automation, capital investments, vegetation management, and enhanced hazard tree removal - align with strategies to provide step improvements in reliability performance. Support adequate controls and business processes in place to satisfy applicable regulations. Finally, continue to support effective execution and refinement of emergency preparedness and response plans.

Objective 4: Personal Development - (All Measures)

Develop key internal and external relationships which help to build on utility knowledge. Participate in industry forums to build professional networks, and to help identify industry, customer and

regulatory trends which should be considered when developing long term strategies for EDO. Build on relationships with regulators and other external stakeholders to achieve favorable outcomes related to new capital programs, business process changes, or organizational development.

Objective 5: Electric Distribution Business Strategy and Business Plans - **(All Measures)**

Actively lead development and execution of long term business strategies and plans which provide for the continued provision of safe, reliable, and resilient electric service consistent with evolving customer expectations and regulatory policies. Support flexible processes for effectively aligning and adjusting EDO's organizational, investment, and labor strategies with imminent and future activity in distributed generation, micro- grids, and renewable energy solutions. Assure labor succession plans adequately provide for the technical knowledge and skillsets needed to support design, construction, operation, and maintenance of a distribution grid with significantly advanced intelligence. Continue developing strategy/road map for increased data analytics associated with distribution automation and advanced metering infrastructure.

Electric Distribution-SM2

Objective 1: Management Objective - (All Measures)

Actively support company initiatives for safety, wellness, diversity, affirmative action, performance management, employee development and customer focus, while modeling company values and behaviors

Objective 2: Safety Performance - (Corporate Safety)

Ensure, without compromise, that safety excellence is the core expectation of business operations, and that management and employees are responsible and accountable for a safe work environment.

Ensure hazard assessment and mitigation plans are completed for all responsibility areas, placing emphasis on performing risk analysis where personnel, work practices, technology, or business processes have changed. Continue to refine key business processes and leading safety indicators to influence desired safety cultures and behaviors. Continue to focus on initiatives to reduce unintended outages and vehicle incidents.

Objective 3: Financial Performance - (Cost Control)

Support attainment of 2018 COO financial targets through effective management of resources and execution of the 2018 EDO Business Plan.

Work closely with Budgeting and Forecasting, and other LOB Officers to support attainment of COO budget commitments, effectively modifying business plans, resource levels, or work performed to meet budget constraints or new targets. Ensure adequate business processes and

organizational structure are in place to support efficient execution of capital programs. Ensure adequate controls are in place to accurately monitor and forecast budget trends and variances, and to assure timely and accurate accounting of investments and expenses.

Objective 4: Operational Performance - **(All Measures)**

Direct resources under responsibility towards attainment of 2018 performance targets. Ensure EDO's organizational structure and business processes provide for safe, effective, and timely restoration of services following routine and emergency outage events. Ensure EDO's reliability programs - distribution automation, capital investments, vegetation management, and enhanced hazard tree removal - align with strategies to provide step improvements in reliability performance. Ensure adequate controls and business processes are in place to satisfy applicable regulations. Finally, continue to direct effective execution and refinement of emergency preparedness and response plans.

Objective 5: Electric Distribution Business Strategy and Business Plans - (All Measures)

Actively lead development and execution of long term business strategies and plans which provide for the continued provision of safe, reliable, and resilient electric service, and effectively align the organization and electric distribution system with evolving customer expectations and regulatory policies. Develop flexible processes for effectively aligning and adjusting EDO's organizational, investment, and labor strategies with imminent and future activity in distributed generation, micro-grids, and renewable energy solutions. Assure labor succession plans adequately provide for the technical knowledge and skillsets needed to design, build, operate, and maintain a distribution grid with significantly advanced intelligence.

<u>**Electric Distribution-SM3**</u>

Objective 1: Management Objective - (All Measures)

Actively promote company initiatives for safety and wellness, customer experience, inclusion and employee engagement, affirmative action, employee performance and development, while modeling leadership commitments, values and behaviors.

Objective 2: Safety Performance - (Corporate Safety)

Ensure, without compromise, that safety excellence is the core expectation of business operations, and that management and employees are responsible and accountable for a safe work environment.

Ensure hazard assessment and mitigation plans are completed for all responsibility areas, placing emphasis on performing risk analysis where personnel, work practices, technology, or business processes have changed. Continue to refine key business processes and leading safety indicators to influence desired safety cultures and behaviors. Continue to focus on initiatives to reduce

unintended outages and vehicle incidents.

Objective 3: Financial Performance - (Cost Control)

Support attainment of 2018 COO financial targets through effective management of resources and execution of the 2018 EDO Business Plan.

Work closely with Budgeting and Forecasting, and other LOB Officers to support attainment of COO budget commitments, effectively modifying business plans, resource levels, or work performed to meet budget constraints or new targets. Ensure adequate business processes and organizational structure are in place to support efficient execution of capital programs. Ensure adequate controls are in place to accurately monitor and forecast budget trends and variances, and to assure timely and accurate accounting of investments and expenses.

Objective 4: Operational Performance - **(All Measures)**

Direct resources under responsibility towards attainment of 2018 performance targets. Ensure EDO's organizational structure and business processes provide for safe, effective, and timely restoration of services following routine and emergency outage events. Ensure EDO's reliability programs - distribution automation, capital investments, vegetation management, and enhanced hazard tree removal - align with strategies to provide step improvements in reliability performance. Ensure adequate controls and business processes are in place to satisfy applicable regulations. Finally, continue to direct effective execution and refinement of emergency preparedness and response plans.

Objective 5: Personal Development - (Customer Satisfaction)

Develop key internal and external relationships which help to build on utility knowledge. Participate in industry forums to build professional networks, and to help identify industry, customer and regulatory trends which should be considered when developing long term strategies for EDO. Build on relationships with regulators and other external stakeholders to achieve favorable outcomes related to new capital programs, business process changes, or organizational development.

Objective 6: Electric Distribution Business Strategy and Business Plans - **(All Measures)**

Actively lead development and execution of long term business strategies and plans which provide for the continued provision of safe, reliable, and resilient electric service, and effectively align the organization and electric distribution system with evolving customer expectations and regulatory policies. Develop flexible processes for effectively aligning and adjusting EDO's organizational, investment, and labor strategies with imminent and future activity in distributed generation, micro-grids, and renewable energy solutions. Assure labor succession plans adequately provide for the technical knowledge and skillsets needed to design, build, operate, and maintain a distribution grid with significantly advanced intelligence.

Energy Supply and Analysis-SM1

Objective 1: Management Objective - (All Measures)

Actively promote company initiatives for safety and wellness, customer experience, inclusion and employee engagement, affirmative action, employee performance and development, while modeling leadership commitments, values and behaviors.

Objective 2: Coal Inventory Optimization – (Cost Control)

Description: Establish appropriate inventory ranges and manage fuel stock within these limits to minimize operational risks on the lower end of the range and to avoid financial penalties on the higher end of the range.
Measurement: Monitor and report on a monthly basis against inventory limits established through the Coal Inventory Optimization Analysis. Provide explanations of variances. Identify, analyze and recommend options to be implemented to either continue to manage inventory levels within these ranges or when market conditions or fleet operations dictate, to manage inventory levels outside of these ranges.

Utilize the short term inventory forecasting process to routinely report current and projected inventory levels (and actions being taken) at Daily Operations meetings and Energy Supply and Analysis Metrics meetings.

Objective 3: Fuel Costs - (Cost Control)

Achieve fuel-related costs across the fleet.

Oversee fuel procurement activates to ensure compliance with the Fuel Procurement Strategy, the ALM, SOX Controls, and Fuel Procurement Policies and Procedures.

Objective 4: MTP Budgeting/Planning - (Cost Control)

Support the development of the Operations MTP and the assessment as to how future regulatory compliance obligations affect fuel utilization/by-product beneficial use and costs as well as supply side alternatives and costs, capital investments and on-going O&M.

Gain approval of coal forward price curves and inventory limits as a component of the MTP budgeting/planning process. Provide forward pricing for other commodities procured for power generating facilities.

Share with colleagues in Energy Supply and Analysis, Technology Research and Analysis, External Affairs, etc. information learned from meetings with various outside industry

groups that Fuels participated in during the year.

Objective 5: Special Projects - (Customer Reliability)

Continue Implementation of fleet wide CCR beneficial use strategy. Continue implementation of Refined Coal Project.

Participate in and advocate the company's and/or the Energy Supply and Analysis position.

Energy Supply and Analysis-SM2

Objective 1: Management Objective - (All Measures)

Actively promote company initiatives for safety and wellness, customer experience, inclusion and employee engagement, affirmative action, employee performance and development, while modeling leadership commitments, values and behaviors.

Objective 2: Power Supply Operations - (All Measures)

Provide leadership for managing the following activities:
- Dispatch operations
- Trading operations
- Marketing activities
- Maintaining reserve sharing arrangement
- others as identified

Achieve cost of serving native load ($/MWH) target

Objective 3: Natural Gas Procurement - (Cost Control)

- Increase depth of natural gas trading and scheduling experience within the group.
- Work with Energy Planning, Analysis, and Forecasting (EPAF) to periodically review the optimal portfolio of firm/non-firm transport to provide reliable gas supply at the least cost.
- Work with the risk manager within EPAF to determine the optimal natural gas contract terms for CR7 fuel portfolio.
- Continue the RFP and award recommendation process for procuring future supplies of gas, consistent with the fuel strategy.

Objective 4: Municipal and Co-owner Relationships - (Customer Satisfaction)

- Support commercial activities and business relationships with wholesale municipal customers
- Support relationship with Trimble County Co-owners

<u>Energy Supply and Analysis-SM3</u>

Objective 1: Management Objective - (All Measures)

Actively promote company initiatives for safety and wellness, customer experience, inclusion and employee engagement, affirmative action, employee performance and development, while modeling leadership commitments, values and behaviors.

Objective 2: Provide Departmental & Corporate Leadership on Key Issues - (All Measures)

Extend capabilities of department to support decisions across key areas and issues, improve tools, and understand major policy implications.

Objective 3: Oversee Dept Operations to Ensure Objectives are Met - (Cost Control)

Provide appropriate oversight and leadership to ensure budgets are met, analysis is timely, and filings are supported appropriately.

Objective 4: Make Individual Contributions on Special Projects as Directed - (All Measures)

Participate in special projects, including policy-related and broader energy use issues that arise during the year.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 48

Responding Witness: Gregory J. Meiman

Q-48. Reference the Companies' response to AG DR 1-120. The Mercer study introduction (of Attachment 4 to Tab 60 of the Companies' Applications) states that Mercer evaluated "benefits against organizations most similar to the client. Thus, utility companies are the most similar to LKE and are the primary market comparison." The lists of utilities in the study appendix includes such companies as California ISO, ERCOT, Northeast Texas Electric Cooperative, and PJM Interconnection, L.L.C. Provide the following:

   a. Explain how the companies specified in this data request can be characterized as among those "most similar to LKE."

   b. Provide the specific criteria by which peer companies were chosen for the Mercer study.

A-48.
   a. The companies specified in this data request were part of the comparison group for the health/group and time loss comparison, but not part of the comparison group for the retirement review. To select these companies, Mercer relied upon existing data in its US Benefits Database. The full database of approximately 1,000 companies was scoped to all companies in the utility industry and then further refined to exclude electric cooperatives. The Independent System Operators (California ISO, ERCOT, and PJM Interconnection, L.L.C., as listed above), which are governed by FERC (Federal Energy Regulatory Commission), operate a region's electricity grid, administer a region's wholesale electricity markets, and provide reliability planning for a region's bulk electricity system. Northeast Texas Electric Cooperative is an association that advocates for cooperatives in Texas. These companies were selected based on (1) their impact on companies in the utility industry and (2) the similarity in the backgrounds and experience of the employees hired.

   b. According to Mercer, they looked to three markets for benchmarking health/group, time loss, and retirement benefits: utilities, companies headquartered in KY, and the national market. The primary market was utilities, as those companies are most similar to LG&E/KU. For the

health/group and time loss comparison, the primary market companies are listed on slide 9 of 13 of the study provided by Mercer (which was attached as Attachment 4 to tab 60 to the Application). A description of how those companies were selected can be found in part a above.

For the retirement comparison, the primary market companies are listed on slide 10 of 13 of the study provided by Mercer. First, Mercer identified all organizations that are involved in the energy sector in any way, including publicly-traded, wholly-owned subsidiary, private, tax-exempt, and municipal organizations. Next, Mercer narrowed the organizations to those that provide either electricity or gas to residential customers through regulated rates. Big Rivers Electric Corporation, East Kentucky Power Co-op, and Tennessee Valley Authority were also retained, as these have a significant local presence in the utility space. Further, Mercer narrowed down the organizations by selecting those regulated utilities who had a customer base most similar to LG&E/KU. Mercer used number of customers as the primary scope comparison. Utilities with 1/3 to 3X the customer base of LG&E/KU were included. This scoping is consistent with Mercer's standard comparison group development practice.

Finally, Mercer identified which of the remaining regulated utilities had sufficient publicly disclosed data pertaining to current and past retirement benefits. Additionally, this group includes three utilities (Big Rivers Electric Corporation, East Kentucky Power Co-op, and Tennessee Valley Authority) that are not regulated utilities but have a significant local presence in the utility industry.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 49

Responding Witness: Daniel K. Arbough

Q-49. Reference the Companies' response to AG DR 1-82, AG DR 1-11, and the amounts provided in account 901 for the base and test period.

    a. Provide a breakdown of the base and test period amounts provided for this account, including the amounts dedicated to economic development, in whole or in part.

    b. Indicate which expenses provided in subpart (a), above, are dedicated, in whole or in part, to economic development.

    c. Are any amounts reflected in account 901 related to lobbying or government relations? If so, provide those amounts related to lobbying or government relations.

    d. Provide the total amounts, by Company, for the salaries and costs related to each lobbying, government relations and economic development.

A-49.

    a.

LG&E	Base Period	Test Period
Business Services	896,599	990,283
Retail Business Systems, Strategy & Learning	801,442	849,452
Residential Service Center	340,855	471,290
Business Offices	189,460	241,568
VP Customer Services	220,777	154,411
Director Revenue Integrity	101,695	103,742
Civic Affairs	72	
Corporate	(445)	
Total	**2,550,454**	**2,810,746**

b. Of the amounts above, the portion related to economic development is included within Business Services: $896,599 in the base period and $990,283 in the test period.

c. No.

d. Account 901 contains no lobbying and government relations costs. The salaries and other costs for economic development in account 901 are below:

Business Services	Base Period	Test Period
Labor	818,428	837,167
Nonlabor	78,171	153,116
Total	**896,599**	**990,283**

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 50

Responding Witness: Gregory J. Meiman

Q-50. Reference the Companies' response to AG DR 1-116. Explain why the Companies refuse to use regional comparisons for the Company's pay and compensation.

A-50. Organizations like to assess as robust and varied market compensation data as available when conducting benchmarking studies, but due to limited survey participation and data samples, regional comparisons, whether for general industry or utility/energy industry are not always available. Companies that participate in the compensation surveys change from year to year and it is each individual company's decision to determine whether to participate or not in a given year. Neither the Companies nor WTW determine the participants.

In the absence of robust regional compensation data comparisons, WTW provided geographic differential data, as was noted in their 2018 General Rate Case Target Total Cash Compensation Study.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 51

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-51. Reference the Companies' response to AG DR 1-73.

    a. Provide representative examples used during the most recent 12-months for each of the "Advertising Categor[ies]" in which the Companies are requested recovery for in the test period. Each item provided in response to this request should indicate the time period it was sent to customers.

A-51.
    a. See attached.

FACEBOOK CAROUSEL
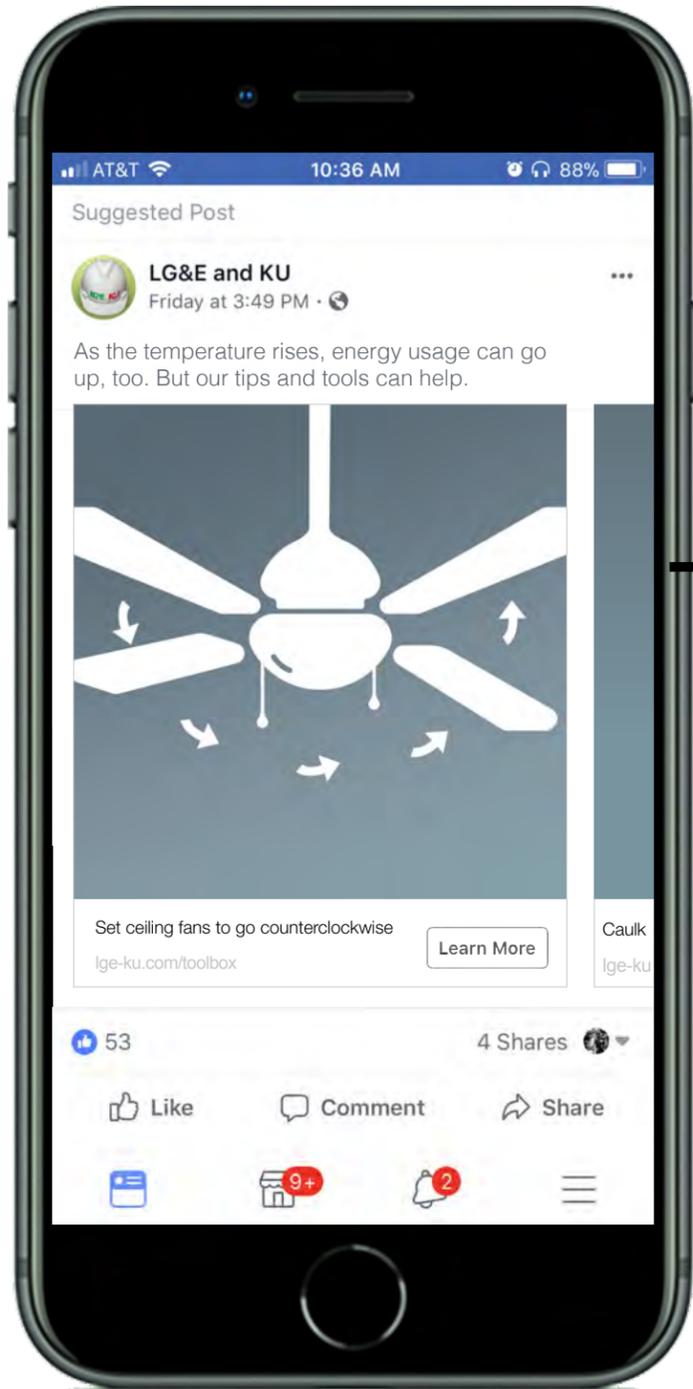
ANIMATION :

Ceiling fan will turn counterclockwise

ANIMATION :

Caulk gun moves down to weather strip window frame

ANIMATION :

Thermostat number and notch moves up 2 degrees

ANIMATION :

Lines coming from lightbulb blink on in rotation.

101428_LGEku_MayEE_FBcar_
a1080x1080_01.psd

101428_LGEku_MayEE_FBcar_
a1080x1080_02.psd

101428_LGEku_MayEE_FBcar_
a1080x1080_03.psd

101428_LGEku_MayEE_FBcar_
a1080x1080_04.psd

INSTAGRAM CAROUSEL
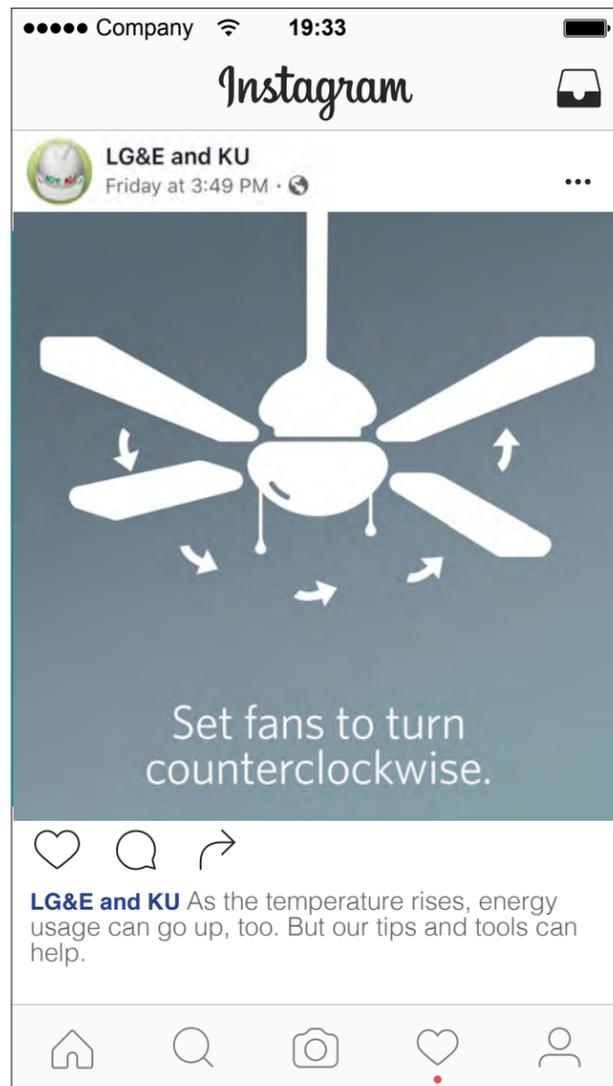
ANIMATION :

Ceiling fan will turn counterclockwise

ANIMATION :

Caulk gun moves down to weather strip window frame
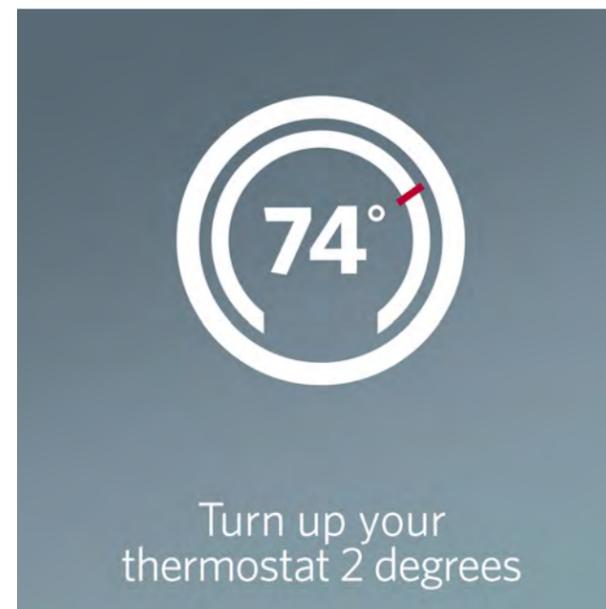
ANIMATION :

Thermostat number and notch moves up 2 degrees

101428_LGEku_MayEE_INcar_
a1080x1080_01.psd

101428_LGEku_MayEE_INcar_
a1080x1080_02.psd

101428_LGEku_MayEE_INcar_
a1080x1080_03.psd
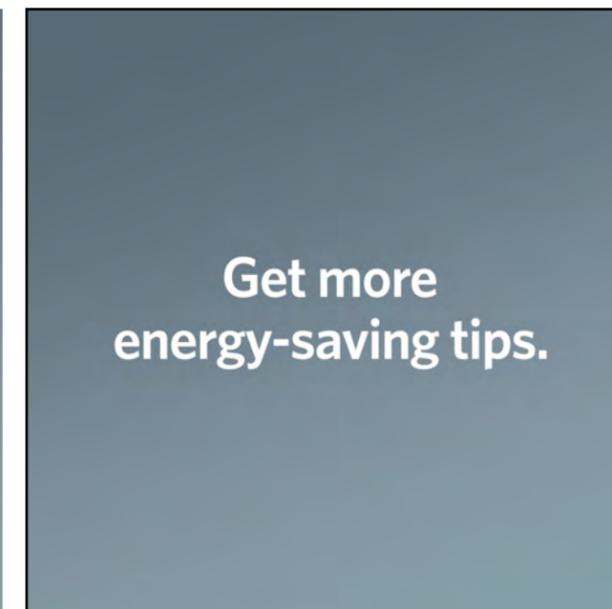
101428_LGEku_MayEE_INcar_
a1080x1080_04.psd

FACEBOOK VIDEO POST

●●●○○ Verizon 🛜   9:59 AM   ✈ ⋇ 94% ▉

LG&E and KU
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As temperatures rise, our toolbox can help you keep a lid on rising energy usage. See how.

▶

Summer energy-savers
Check out our toolbox today. The tips and tools can help you use energy more wisely – and save money, too!.
Lge-ku.com/toolbox   Learn More

76 Likes 5 Comments 11 Shares

👍 Like   💬 Comment   ➤ Share
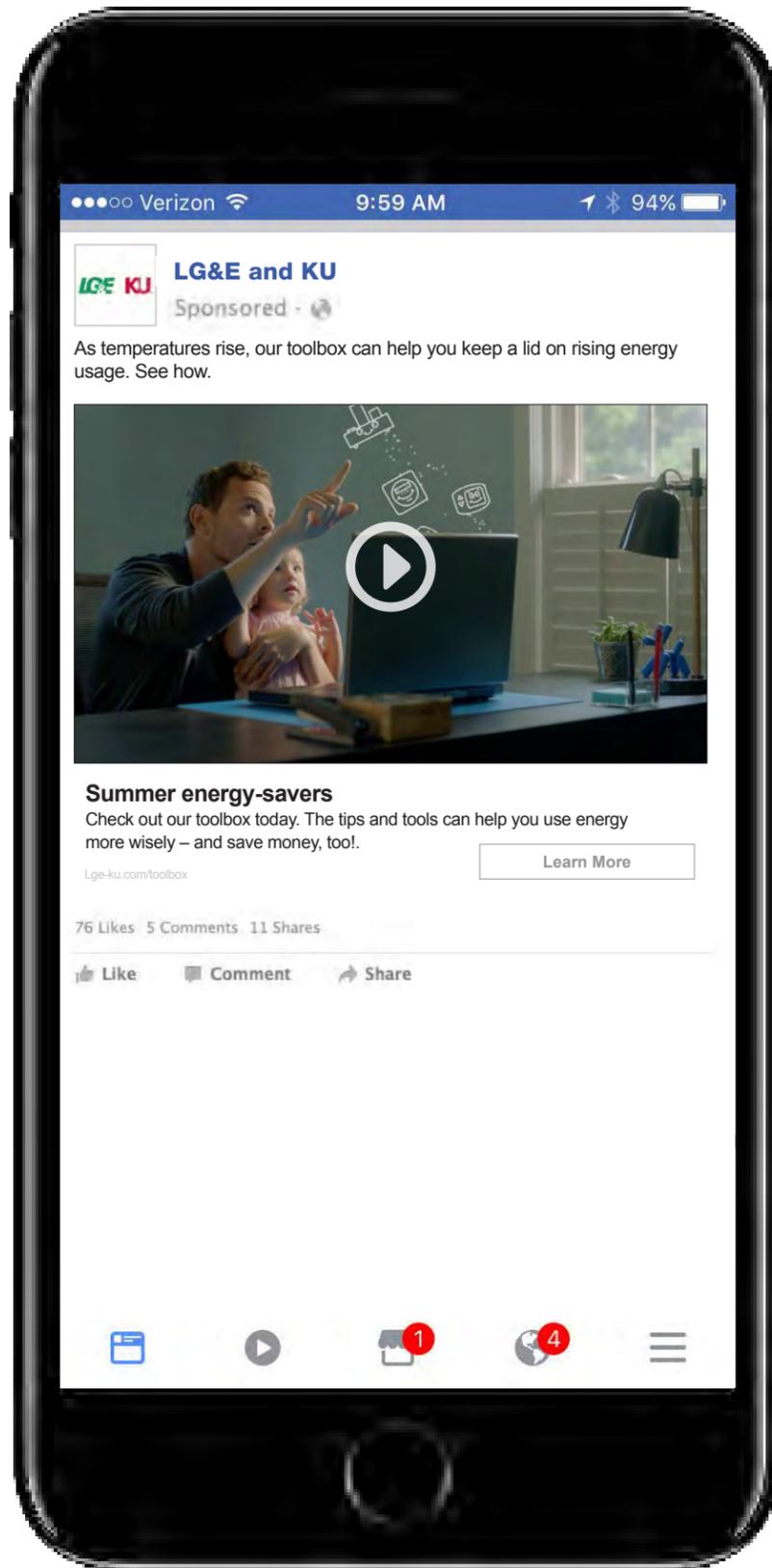
Empowering you to save this holiday season.

Tirza,
real LG&E employee

LG&E
a PPL company

a PPL company

LG&E

Louisville Gas and Electric Company
220 West Main Street
Louisville, KY 40202

Turn your thermostat down two degrees.

Caulk gaps around windows and doors.

Install plastic film to insulate windows.

Change furnace filters regularly to improve HVAC efficiency.

Use LED lights and holiday timers so they're only on when you're home.

'Tis the season to save energy and money!

Cold temperatures can have a big impact on your energy bills. At LG&E, we're empowering you to save with lots of quick, easy tips that can help you reduce your energy usage and save money. Visit **lge-ku.com/tips** for more great ways to save – plus helpful how-to videos.

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LG&E **KU.**
PPL companies

e-SMARTkids
students teachers parents

Kids

▼ Get SMART!
  - Electrical Safety-SMART!
  - Natural Gas Safety-SMART!
▶ Videos
▶ Games
  Natural Gas FAQ
▶ Home Inspections

811.
Know what's below.
Call before you dig.

If you have a natural gas emergency please call our statewide emergency number: 502-589-1444 (outside Louisville call 800-331-7370).

Natural Gas Safety-SMART!

Natural Gas-SMART! Certificate
Print this first and track your progress!

Natural Gas Science
What FOSSILS and Geologists have to do with it

The Travels of Natural Gas
Take a JOURNEY Through Gas Pipelines

Gas Pipeline Safety
RECOGNIZE and Respond to a GAS LEAK

Using Gas Safely
CARBON MONOXIDE ALARM CE
Proper Usage and EMERGENCY RESPONSE

Using Gas Efficiently
SAVE ENERGY in your home

Tell Me More
FAQs HISTORY Science & CAREERS
NATURAL GAS

LG&E AND KU ENERGY LLC Acct # 4044-1
Date: 4/16/2018

YPM.Net ONLINE CLIENT SERVICES
Yellow Pages Advertising Order

Resources
Print/Zoom Image
Print Form

Directory	Closing Date	Publication Date	Art ID#
IN Southern IndianaArea (YP) (Dir.#24016)	5/17/2018	8/2018	372OI02401618B

Item Code	Heading
White Page-3" Display Ad (W6DA)	WHITE PAGES

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Date:_____

Artwork Approved By:_____

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lge-ku.com
Electric Trouble/Power Outage-24 Hours
.... 502 589-1444
Natural Gas Trouble/Emergency-24 Hours
.... 502 589-1444
Residential Customer Service
.... 502 589-1444
Outside Louisville
Toll Free "1".................... 800 331-7370
Business Customer Service
.... 502 627-3313
Outside Louisville
Toll Free "1".................... 800 331-7370
Corporate Offices-Louisville
.... 502 627-2000

W6DA (YP 3 Col) / White Page: 4 Col
DIR 24016 IN Southern IndianaArea
PUB CO 0913 ACCT 4044
12 x 18
W6DA-YP3-24016 IN Southern IndianaArea
ART ID#372OI02401618B

Directory: 24016 IN Southern IndianaArea
Heading: WHITE PAGES
Ad Item: W6DA

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POWER SOURCE

OCTOBER 2018

TRANSMISSION WORK ENHANCING RELIABILITY FOR CUSTOMERS; ECONOMIC DEVELOPMENT FOR STATE

Interstate highways may be our fast-paced transportation routes on the ground, but take a look above, and you'll find multilane energy highways, in the form of overhead transmission lines, in the air.

Transmission lines are high-voltage power lines, energized up to as much as 765,000 volts, which connect the entire energy grid. The lines transport electric current from generating stations where energy is produced to substations where it's stepped down and transported through the distribution lines that serve commercial areas and neighborhoods.

When outages occur within a transmission system, they can have widespread, large-scale impacts – like the Northeast Blackout of 2003. Now recognized as one of the worst power outages in U.S. history, the incident started when a high-voltage power line in Ohio brushed against overgrown trees, causing it to shut down and create an overload and blackout that cascaded across eight U.S. states and Canada, impacting more than 50 million people.

Minimizing the potential for these types of large-scale outages is one of many reasons keeping transmission systems up-to-date is so critical.

We are working on ongoing transmission system improvements that include replacing aging equipment such as wooden poles, cross arms, lines and substation controls. We are also implementing cycle-based tree trimming and focused efforts to remove dead, dying and diseased trees around transmission infrastructure. The ongoing work will establish a schedule for keeping trees a safe distance from transmission lines. Failure to maintain the safe distance can be punishable by a significant fine from the North American Electric Reliability Corporation (NERC).

It's anticipated these enhancements, along with other infrastructure upgrades, will significantly reduce the duration of outages experienced by customers and ensure a safe, reliable system far into the future.

On the natural gas side, we are replacing aging steel service and transmission lines with new plastic pipe for increased reliability. Also, more than $11.5 million in upgrades are underway at our Muldraugh Compressor Station, including a major pipeline replacement.

THERE'S MORE

Go to lge-ku.com to:
» Check out tips to make sure your furnace is ready for winter
» Get more predictable monthly payments with our Budget Payment Plan
» Take advantage of our Fridge and Freezer Recycling program before it expires

SAFETY, SAFETY AND SAFETY: THE THREE REQUIREMENTS FOR YARD WORK THIS FALL

Autumn is the time of year to wrap up that last bit of yard work before settling in for the winter to come. There'll be leaves to rake, gutters to clean and maybe some fall planting in anticipation of next spring. And while the seasons are changing, one thing that never goes out of season is safety. Please heed these simple tips so you won't "fall" into any trouble:

- **Raking** – Dry leaves can spark a fire. Make sure they are cleared away from any outdoor lighting, power outlets and power cords.

- **Cleaning** – Getting gunk out of the gutters usually means using a ladder. Remember to carry your ladder parallel to the ground while checking for power lines and trees that may be touching power lines before raising the ladder to stand it up.

- **Planting** – Digging a hole for a new bush, shrub or tree requires a little planning. At least two days before your shovel hits the ground, contact **811**. Simply dial 8-1-1 or make your request online at **811now.com**. That alerts member utilities, including LG&E, to mark any underground wires, cables or pipelines so you can avoid digging in the wrong spot and prevent a serious accident or injury.

Whether you're working in the yard or just enjoying some nice weather by taking a walk through the neighborhood, your nose can keep you safe. A rotten-egg or sulfur odor could signal a natural gas leak. If you suspect a leak, get away from the affected area. Once safely away, call LG&E at **502-589-1444** (call **800-331-7370** outside Louisville) and also call **911** to report the situation.

RAYNEISHA RAVES ABOUT PAPERLESS BILLING

You've read it here before: a little less clutter can make life a little less hectic. That's why LG&E offers paperless billing. Just sign up through your online account (or easily create one) at **my.lge-ku.com**. Here's what one of our employees has to say about going paperless:

"I think paperless billing is awesome. I'm not a big fan of paper mail because it becomes too much to go to a mailbox every day, especially having to walk a distance with a very active 2-year-old. Paperless is a big convenience because I tend to misplace a lot of mail when I receive it. It's much easier to go back and search **ebill@lge-ku.com** in my email to look at it. It's a great thing when I need to look at my bill as a reference immediately and it's right there!"– **Rayneisha Anderson, customer care representative, Residential Service Center.**

Visit **lge-ku.com/paymybill** to learn more about paperless billing and other payment options.

Sign up for My Notifications and receive timely reminders about the due date of your bill by text, email and/or phone. Visit lge-ku.com/notifications for more information.

SOLAR SHARE PROGRAM NOW SHINES A LITTLE BRIGHTER FOR CUSTOMERS

On August 28 the Kentucky Public Service Commission approved LG&E's request to change the fee structure of the company's Solar Share program.

In an effort to make the program more convenient for those interested in supporting community solar, LG&E proposed including the enrollment fee in the monthly capacity charge, thus creating a slight increase in the monthly charge but no more up-front costs.

LG&E is hoping the change will encourage more customers to support community solar. Those who previously signed up for the program also will benefit from the removal of the up-front fee. The change means the monthly subscription cost for participating customers will increase slightly, from $6.24 per share to $6.27 per share.

"We're always exploring ways to make our offerings more appealing to customers, and gaining KPSC approval on our request to eliminate the up-front enrollment fee will help us build on the early success and customer interest we've seen with our Solar Share program," said David Huff, director of Customer Energy Efficiency and Emerging Technologies. "We're thankful for every customer and employee who has signed up for the program so far. We encourage everyone to take another look at the program and share this exciting opportunity with their friends and families."

In July, the company reached an important milestone with full subscription for the 2,000 shares in the facility's first section.

"We're still actively working to seek subscriptions for the remaining sections, and we appreciate employees' continuing to subscribe and spread the word about the program," added Huff.

Construction on the first fully subscribed section is anticipated to begin in early 2019. Visit lge-ku.com/solar-share to learn more about the program.

FIRE SAFETY: BE SURE TO CHECK SMOKE DETECTORS AND CHANGE BATTERIES REGULARLY

October is national Fire Prevention Month and is paired with a reminder to change your smoke detector batteries. That simple act can literally be a lifesaver, alerting you of a fire in time to escape safely and call emergency responders.

Smoke detector batteries should be checked each month (by pushing the test button on the detector) and replaced at least once a year. Smoke detectors should be replaced every 10 years.

In the event of a fire, the National Fire Prevention Association recommends having a preplanned meeting site a safe distance from your home so everyone knows where to gather when the smoke detector goes off. It's also important to make sure windows and doors leading outside open easily and are not blocked by any clutter.

Visit nfpa.org to learn more about fire safety.

OUR OFFICES WILL BE CLOSED FOR THANKSGIVING, BUT OUR SERVICE TO YOU NEVER SHUTS DOWN

Wasn't it summer just a little while ago? It's hard to believe, but the holidays are practically upon us. So, this is a reminder that LG&E's customer service center and call centers will be closed Thursday, November 22 and Friday, November 23 in observance of Thanksgiving.

Not to worry, as always, we're working nonstop to bring you safe, reliable, affordable energy. Our technicians will be on the job to ensure you have all the power you require to meet your holiday needs. And if some incident does cause a power outage, they will be on the scene faster than you can say "pass the dressing" to make the necessary repairs.

Also, remember that your LG&E payment is never due on a day our offices are closed, but you can make a payment. Take advantage of any of the available payment options, including:

- **Phone** – call **502-589-1444** (call **800-331-7370** outside Louisville) and press 1-2-3.
- **Online** – pay via your online account. (If you don't have one, easily create an account at **my.lge-ku.com**.)

Visit **lge-ku.com/paymybill** to learn more.

LG&E Contact Information

Online – My Account
lge-ku.com

By Phone
502-589-1444
(Call 800-331-7370 outside Louisville)
Monday–Friday
7 a.m.–7 p.m. (Eastern Time)
Anytime day or night (self-service)

For Hearing- or Speech-Impaired
Dial 711

Business Service Center
502-627-3313
(Call 800-331-7370 outside Louisville)
Monday–Friday
8 a.m.–6 p.m. (Eastern Time)

In-Person
Customer Service Walk-In Center
701 South Ninth Street
Monday–Friday
8 a.m.–5 p.m. (Eastern Time)

Kentucky 811– Locate Service
Dial 811

Editor
Cheryl.Williams@lge-ku.com

Visit our website:
lge-ku.com

Like us on Facebook (facebook.com/lgeku) and follow us on Twitter (@lgeku) and Instagram (lge_ku).

NATIONAL PIPELINE MAPPING SYSTEM

The National Pipeline Mapping System (NPMS) website – https://www.npms.phmsa.dot.gov/PublicViewer/ – enables users to view NPMS data one county at a time. NPMS data consists of gas transmission pipelines and hazardous liquid trunk lines. It does not contain gathering or distribution pipelines, such as lines which deliver gas to an individual customer's home. Therefore, not all pipelines in an area will be visible in the public map viewer.

NPMS data is for reference purposes only. It should never be used as a substitute for contacting Kentucky 811 prior to excavating.

LG&E'S INTEGRITY MANAGEMENT PROGRAM

Our lines are monitored and inspected so we can locate and fix potential problems before they occur. We also implement a pipeline integrity management program that includes identifying areas along our pipelines where the consequences of a failure would be significant, conducting inspections to verify the integrity of the pipeline, implementing pipeline safety communications plans, identifying pipeline risks and implementing measures to reduce pipeline risks. Additional natural gas and pipeline safety information, including emergency preparedness, land-use practices, carbon monoxide safety and the importance of digging safely can be found on our website: **lge-ku.com/customer-service/public-safety**

FOR ANY NATURAL GAS CONCERN OR EMERGENCY, CALL LG&E at 502-589-1444.

Individuals outside Louisville may call 800-331-7370. You can reach us 24 hours a day, 365 days a year.

LG&E
a PPL company

Before digging,

contact Kentucky 811 (by phone when you dial 8-1-1 or online using the One Click option at 811now.com) to have your underground lines marked free of charge.

NATURAL GAS & PIPELINE SAFETY FOR YOU.

You live or work near a natural gas pipeline. Please read this IMPORTANT INFORMATION.

LG&E
a PPL company

LOOK FOR MARKERS

Our underground pipelines are the safest, most efficient and reliable way to deliver natural gas to your home or business. Unfortunately, residential and commercial development in once-rural areas is encroaching on pipeline rights-of-way with increasing frequency. Encroachment can present safety concerns for local residents and for the physical integrity of the pipeline itself. To help prevent encroachment and excavation-related damage to pipelines, we install brightly colored signposts along the pipeline right-of-way to indicate the presence – but not necessarily the exact location – of underground pipelines. Pipeline markers come in a variety of shapes and sizes, but they all contain important information, including emergency contact information for LG&E or the company that operates the pipeline.
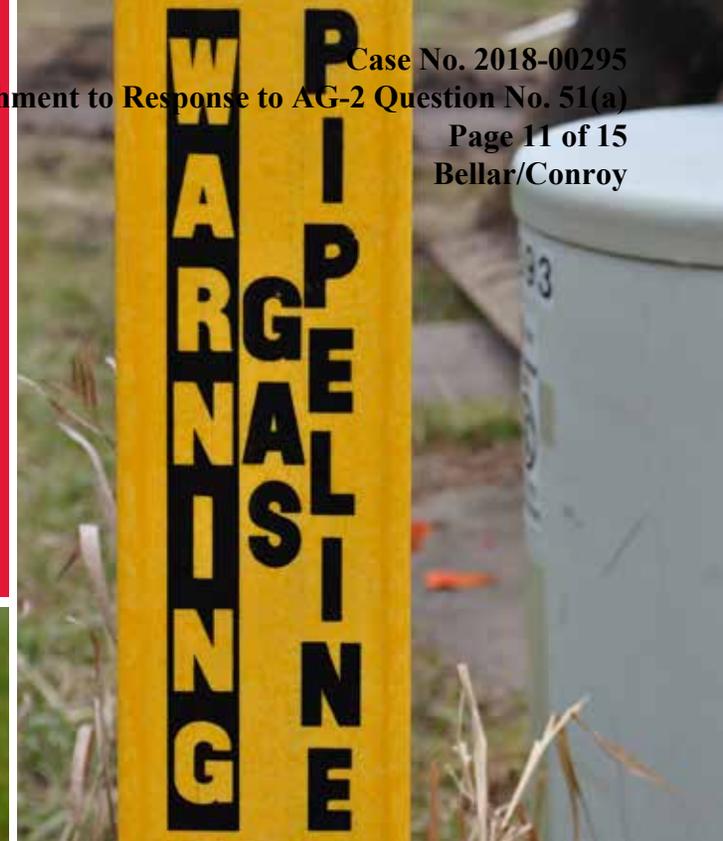
LG&E CARES

LG&E operates 4,600 miles of natural gas pipelines in 20 counties in Kentucky and Southern Indiana, transporting and delivering natural gas to 326,000 customers. We purchase natural gas from national pipeline operators and deliver it directly to our customers or store it for later use when our customers need it. We have resources available to respond promptly to a gas pipeline emergency, and we have ongoing relationships with emergency response agencies in our area who are:

- Trained to identify risks to help prevent gas emergencies.

- Prepared to respond to a gas emergency if one were to occur.

Hazards associated with pipeline failure include blowing gas with potential of a fire or explosion and, if gas is present in a confined space, possible asphyxiation. The current issue of *Power Source*, which came with this month's bill, includes tips for detecting leaks inside or outside your home.

Scratch and sniff this flame for natural gas odor.

WHAT IS A RIGHT-OF-WAY?

A pipeline right-of-way or easement is a corridor or strip of land that surrounds a pipeline. The right-of-way enables us to construct, operate, test, inspect, maintain and protect our pipelines. Access to the right-of-way often is inhibited by trees and other vegetation, fences, buildings and other structures. We encourage residents, excavators, land developers and governmental agencies to contact us during planning stages to help prevent obstructions which delay our response to emergencies and hinder our ability to operate effectively and efficiently.

DIG WITH CARE – IT'S THE LAW

Before digging, ensure the locations of underground utilities in the area are marked by contacting 811 (by phone when you dial 8-1-1 or online with the One Click option at **811now.com**). When you submit your request, Kentucky 811 will coordinate with us (and other member utilities) to mark – free of charge – our underground utilities. The law is designed to protect you and your property when you:

1. Contact 811 (by phone when you dial 8-1-1 or online with the One Click option at **811now.com**) at least two business days before you dig.

2. Wait until the lines have been marked.

3. Avoid digging near the marked areas. In fact, Kentucky law requires you to observe a safe tolerance zone by digging non-intrusively within 18" on either side of the utility.

LG&E
a PPL company

ELECTRIC **SAFETY**

ELECTRIC SAFETY

We work to provide safe, reliable service 24 hours a day, every day, but we can't guarantee uninterrupted service all the time. We all know a power outage can be a big inconvenience, but there are some key steps you can take to stay safe.

To report downed lines or an outage

LG&E customers: 502-589-1444
(toll free: 800-331-7370)

Safety first!

Stay away from all fallen wires and anything, such as a tree limb, that may be in contact with them. Camp stoves and charcoal grills should never be used indoors because they can produce deadly fumes. When using portable generators, always follow the manufacturer's instructions and operate in a well-ventilated area.

Turn off your major appliances

This includes electric stoves, ovens, washers and dryers. Unplug sensitive equipment such as televisions and computers. This reduces the electrical demand when power is restored and significantly reduces the chance of damage from electrical surges.

Visit **lge-ku.com/safety/electric** for more tips on indoor and outdoor electric safety.

Our energies go to serving you.

LG&E
a PPL company

EXTREME HEAT =
HIGHER ENERGY USE.

We have tips and tools to help.

LG&E
a PPL company

HOT WEATHER TIPS

- Remember that *insulation* and *sealing air leaks* can improve your home's energy performance in the summer as well as the winter because they help you keep the cool air you have paid to cool inside your home.

- *Plant trees or shrubs* to shade air conditioning units, but do not block the air flow. Place a room air conditioner on the north side of the house. A unit that operates in the shade uses less energy than one operating in the sun.

- *Do not place lamps* or electronic equipment, such as a TV set, *near your home's thermostat*. The thermostat senses heat from these appliances, which can cause the air conditioner to run longer than necessary.

- *Use a fan* even when your air conditioner is running so you can spread the cooled air more effectively throughout your home without having to adjust the thermostat.

- *Adjust your home's thermostat* up two degrees in the summer.

- *Whole-house fans* can help cool your home by pulling cool air through the house and exhausting warm air out through the attic. Whole-house fans are effective primarily when they are operated at night because that is typically when the outside air is cooler than the inside.

- *Keep curtains, drapes and blinds closed* during the hottest part of the day to prevent the sun's rays from heating your home.

We've got more tips and tools online — including programs that can lend qualified customers a hand in weatherizing homes and assisting with bills. Visit **lge-ku.com/helpingyou** today.

Our energies go to serving you.

LG&E
a PPL company

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 52

Responding Witness: Daniel K. Arbough

Q-52.   Reference the Companies' response to AG DR 1-78.

    a. Provide the nature of the two litigation matters, and explain why they are beyond the Company's control.

    b. Explain why ratepayers should bear these costs.

    c. What is the status of these two litigation matters, and when are these two litigation matters expected to be resolved?

    d. How much is included in the forecast for these two litigation matters?

    e. How much of the outside services' costs associated with these matters could be recovered through insurance?

A-52.
    a. These litigation matters both involve challenges based on alleged environmental impacts from operations at two of our coal-fired generating stations. The Company is a defendant in these actions, and denies any liability for the matters complained of by the plaintiffs.

    b. The expenses associated with defending these suits are a normal cost of doing business.

    c. Both matters are in the pretrial stage. With no trial date set in either case, a date of resolution cannot be predicted at this time.

    d. $1,560,000 is included in the forecast for outside services related to these matters.

    e. We have placed our carriers on notice in both of these suits, but it is presently unknown how much, if any, coverage will be available in either case.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 53

Responding Witness: Daniel K. Arbough

Q-53.   Reference the Companies' response to AG DR 1-79.

a.   Explain the nature of the expected increased number of "separate matters" forecasted at over $100K in 2018 and 2019, and the single matter forecasted at over $500k in 2018.

b.   Further, explain if the Companies expect and have requested recovery for any expenses relating to the $500k 2018 matter during 2019 or the test period.

A-53.

a.   Refer to PSC 3-22.

b.   All of the categories shown in Attachment to Filing Requirement 807 KAR Section 16(7) I. page 215 of 235 are appropriately included in the revenue requirement calculation.   See attached.   The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 54

Responding Witness: Daniel K. Arbough / Christopher M. Garrett

Q-54. Reference the Companies' response to AG DR 1-71 . Ghent Station revenues were reflected in Accounts 454 Rent from electric property, 456 Other electric revenues, and an offset in 501 Fuel. Trimble County and Mill Creek stations were under contact at the time of the filing, and refined coal revenues are reflected in Account 456 Other electric revenues.

    a. Are rent revenues expected from Trimble County and Mill Creek stations? If the response is affirmative, how much? Provide a breakdown by company.

    b. Are offsets to 501 Fuel expected from Trimble County and Mill Creek stations? If the response is affirmative, how much? Provide a breakdown by company.

A-54.

    a. The Trimble County station refined coal contract was finalized in October 2018. Anticipated rent revenues for Trimble County station (75% share) are $2.8 million annually for the contract term which is approximately $1.5 million for LG&E and $1.3 million for KU (approximately $1.2 million for the Kentucky jurisdiction). Rent revenue is variable based on actual tons treated.

    The Mill Creek station refined coal contract is projected to be finalized soon with completion of construction and commencement of production expected in January 2019. Anticipated rent revenues for Mill Creek station are $4.6 million annually and are LG&E only revenues. Rent revenue is variable based on actual tons treated and these revenues will be passed on to customers.

    b. The Trimble County station (75% share) anticipated offset to account 501 is $0.7 million annually for the contract term split approximately $0.4 million for LG&E and $0.3 million for KU (approximately $0.28 million for the Kentucky jurisdiction). This offset is variable based on actual tons treated.

    The Mill Creek station anticipated offset to account 501 is $1.2 million annually for the contract term and is only offsetting LG&E expense. This offset is variable based on actual tons treated.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 55

Responding Witness: Daniel K. Arbough

Q-55. Reference Schedule B-8.

    a. Provide a summary list and amounts of the items in prepayments in the base
    year and forecasted period for each company.

    b. Provide the supporting detail for the summary totals for each company.

A-55.

    a. See attached.

    b. See attached.

Louisville Gas & Electric
Case No. 2018-00295
Prepayment Balances Summary

DESCRIPTION	BASE PERIOD	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	13 MO AVG FORECAST PERIOD
PREPAID INSURANCE	2,700,814	6,793,780	6,197,222	5,600,664	5,004,107	4,580,408	3,983,768	3,441,522	3,431,593	2,834,736	4,005,180	3,408,331	2,811,482	7,281,487	4,567,252
PREPAID RISK MGMT AND WORKERS COMP	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500	90,500
PREPAID ADP FUNDING	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510	34,510
PREPAID OTHER	3,134,501	2,896,977	2,814,196	2,731,415	2,648,635	2,565,854	3,399,340	3,315,060	3,230,779	3,146,499	3,155,618	3,071,137	2,986,657	2,902,176	2,989,565
PREPAID IT CONTRACTS	8,562,557	9,386,251	8,665,936	9,163,832	8,476,231	7,585,665	6,929,445	7,043,113	6,463,391	7,357,226	10,136,943	9,718,227	8,784,501	9,793,919	8,423,437
PREPAID TAXES	1,572,786	616,274	377,146	138,018	2,821,034	2,577,123	2,333,213	2,089,302	1,845,392	1,601,481	1,357,571	1,113,660	869,750	625,839	1,412,754
PREPAID RIGHTS OF WAY	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334	133,334
TOTAL PREPAYMENTS	16,229,002	19,951,625	18,312,844	17,892,274	19,208,350	17,567,394	16,904,109	16,147,341	15,229,499	15,198,285	18,913,656	17,569,699	15,710,733	20,861,765	17,651,352

Louisville Gas and Electric
Case No. 2018-00295
Prepayment Balances Supporting Detail

	APR 2019	MAY 2019	JUN 2019	JUL 2019	AUG 2019	SEP 2019	OCT 2019	NOV 2019	DEC 2019	JAN 2020	FEB 2020	MAR 2020	APR 2020	13 MO AVG FORECAST PERIOD
PREPAID INSURANCE														
BEGINNING BALANCE	2,809,922	6,793,780	6,197,222	5,600,664	5,004,107	4,580,408	3,983,768	3,441,522	3,431,593	2,834,736	4,005,180	3,408,331	2,811,482	4,223,286
PREPAID INSURANCE PAYMENTS	4,580,415	-	-	-	172,941	-	54,610	586,928	-	1,767,293	-	-	5,111,075	944,097
PREPAID INSURANCE AMORTIZATION	(596,558)	(596,558)	(596,558)	(596,558)	(596,640)	(596,640)	(596,857)	(596,857)	(596,857)	(596,849)	(596,849)	(596,849)	(641,071)	(600,131)
ENDING BALANCE	6,793,780	6,197,222	5,600,664	5,004,107	4,580,408	3,983,768	3,441,522	3,431,593	2,834,736	4,005,180	3,408,331	2,811,482	7,281,487	4,567,252
PREPAID OTHER														
TVA FEES:														
BEGINNING BALANCE	433,464	350,683	267,902	185,122	102,341	19,560	853,046	768,766	684,485	600,205	609,324	524,843	440,363	449,239
TVA ADMIN FEE PAYMENTS	-	-	-	-	-	917,767	-	-	-	93,600	-	-	-	77,797
TVA ADMIN FEE AMORTIZATION	(82,781)	(82,781)	(82,781)	(82,781)	(82,781)	(84,281)	(84,281)	(84,281)	(84,281)	(84,481)	(84,481)	(84,481)	(84,481)	(83,765)
ENDING BALANCE	350,683	267,902	185,122	102,341	19,560	853,046	768,766	684,485	600,205	609,324	524,843	440,363	355,882	443,271
MISC PREPAID	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294	2,546,294
TOTAL BALANCE PREPAID OTHER	2,896,977	2,814,196	2,731,415	2,648,635	2,565,854	3,399,340	3,315,060	3,230,779	3,146,499	3,155,618	3,071,137	2,986,657	2,902,176	2,989,565
PREPAID IT CONTRACTS														
BEGINNING BALANCE	8,902,251	9,386,251	8,665,936	9,163,832	8,476,231	7,585,665	6,929,445	7,043,113	6,463,391	7,357,226	10,136,943	9,718,227	8,784,501	8,354,847
PREPAID IT PAYMENTS	1,459,891	255,474	1,478,645	277,839	74,870	309,960	1,085,248	393,128	1,876,410	3,820,164	622,998	107,115	2,076,497	1,064,480
PREPAID IT AMORTIZATION	(975,892)	(975,789)	(980,749)	(965,440)	(965,436)	(966,180)	(971,579)	(972,850)	(982,575)	(1,040,446)	(1,041,714)	(1,040,841)	(1,067,078)	(995,890)
ENDING BALANCE	9,386,251	8,665,936	9,163,832	8,476,231	7,585,665	6,929,445	7,043,113	6,463,391	7,357,226	10,136,943	9,718,227	8,784,501	9,793,919	8,423,437
PREPAID TAXES														
PSC FEES:														
BEGINNING BALANCE	717,384	478,256	239,128	0	2,683,015	2,439,105	2,195,194	1,951,284	1,707,373	1,463,463	1,219,552	975,642	731,731	1,292,394
PSC FEES PAYMENTS	-	-	-	2,926,926	-	-	-	-	-	-	-	-	-	225,148
PSC FEES AMORTIZATION	(239,128)	(239,128)	(239,128)	(243,910)	(243,910)	(243,910)	(243,910)	(243,910)	(243,910)	(243,910)	(243,910)	(243,910)	(243,910)	(242,807)
ENDING BALANCE	478,256	239,128	0	2,683,015	2,439,105	2,195,194	1,951,284	1,707,373	1,463,463	1,219,552	975,642	731,731	487,821	1,274,736
PREPAID SALES & OTHER TAXES	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018	138,018
TOTAL PREPAID TAXES	616,274	377,146	138,018	2,821,034	2,577,123	2,333,213	2,089,302	1,845,392	1,601,481	1,357,571	1,113,660	869,750	625,839	1,412,754
OTHER	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344	258,344
TOTAL PREPAYMENTS	19,951,625	18,312,844	17,892,274	19,208,350	17,567,394	16,904,109	16,147,341	15,229,499	15,198,285	18,913,656	17,569,699	15,710,733	20,861,765	17,651,352

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 56

Responding Witness: Daniel K. Arbough / Christopher M. Garrett

Q-56.   Reference the Companies' response to AG DR 1-86.

   a.   Confirm that the Company has not reflected duplicative charges for the same
        service from more than one service company in the test year in this matter.

A-56.
   a.   The Company confirms that it does not budget duplicative charges.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 57

Responding Witness: Robert M. Conroy / David S. Sinclair

Q-57. Reference the Companies' response to AG DR 1-170.

a. Explain to what degree the Company will allow customers interested in Green Tariff Option #3 to choose or have input into what type of "renewable resource" it receives electricity from under Option #3.

b. Explain whether a customer can replace 10MW of current capacity with capacity from Green Tariff Option #3.

c. Explain, in detail, what the Companies envision the process will be with customers in its response that "The Companies will work with the potential Green Tariff Option #3 customer in any way."

d. Is the Company's response to subpart (h) to AG DR 1-170 indicating that all terms and conditions resulting from Green Tariff Option #3 are negotiable, including how the contract relates to ongoing tariff and rate mechanisms? For instance, is the response indicating that the interaction with certain special contracts may impact certain customers differently as it relates to local school taxes, off-system sales, fuel adjustment clause, applicable demand rates, applicable customer charges, contribution in aid of construction, surcharges, etc.?

A-57.

a. The customer can have input into the type of renewable resource so long as there is a market to procure the requested generation source bound by the terms of the Green Tariff and bilateral contract between the customer and Company. The Company has no interest in limiting the type of renewable resource choices of its customers under Option #3.

b. No. A customer cannot replace any capacity under Option #3.

c. The Green Tariff Option #3 requires a mutually agreed-to bilateral contract between the Company and customer as well as the Company and the renewable

energy provider. The terms of these contracts will be jointly determined in consultation with the potential customer.

d. No. The customer will continue to be billed under the appropriate Company tariff based on their usage and required facilities. The negotiable terms related to Option #3 only include the contractual terms for procuring the renewable resource and how the Company will recover its contract costs from the customer.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 58

Responding Witness: Robert M. Conroy / Elizabeth J. McFarland

Q-58. Reference the Companies' response to Staff DR 2-11.

    a. Confirm that AMI meters are available through the Company's AMS Customer Service Offering.

    b. Confirm that the cost of meters provided through the AMS Customer Service Offering are not recovered through base rates.

    c. Confirm that meters provided through the AMS Customer Service Offering provide the same benefits as those meters provided to customers who enroll in the Solar Share program.

    d. What would the reduction to the revenue requirement be if the Commission required the costs of the AMI meters be recovered via the Solar Share program and not through base rates?

A-58.

    a. Confirmed.

    b. Confirmed.

    c. Confirmed. See the response to PSC 3-5.

    d. There would be no reduction to the revenue requirement. See the response to PSC 3-6.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 59

Responding Witness: Lonnie E. Bellar

Q-59. Reference the Attorney General's request and Companies' response to AG DR 1-170. Further, reference Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, generally.

    a. Confirm that 16 U.S.C. § 824a-3 provides the option for an electric utility to request, and for the FERC to grant, termination of mandatory purchase and sale requirements regarding certain qualifying facilities under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), if the FERC finds that the qualifying facility has nondiscriminatory access to independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy and wholesale markets for long-term sales of capacity and electric energy.

    b. Discuss whether the Companies' believe they adequately considered the impact of RTO membership on their current or future obligations under PURPA.

A-59.

    a. 16 U.S.C. § 824a-3 speaks for itself. See attached copy of the statute.

    b. See the response to PSC 3-30.

16 U.S.C.
United States Code, 2017 Edition
Title 16 - CONSERVATION
CHAPTER 12 - FEDERAL REGULATION AND DEVELOPMENT OF POWER
SUBCHAPTER II - REGULATION OF ELECTRIC UTILITY COMPANIES ENGAGED IN INTERSTATE
COMMERCE
Sec. 824a-3 - Cogeneration and small power production
From the U.S. Government Publishing Office, www.gpo.gov

§824a–3. Cogeneration and small power production

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to—

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities [1] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities

The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

(1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C. 791a et seq.], from the Public Utility Holding Company Act,[2] from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility (other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act [16 U.S.C. 796(17)(E)]) which has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act [2] and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(A) any State law or regulation in effect in a State pursuant to subsection (f),

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 U.S.C. 824i, 824j, or 824k] or the necessary authorities for enforcement of any such provision under the Federal Power Act [16 U.S.C. 791a et seq.], or

(C) any license or permit requirement under part I of the Federal Power Act [16 U.S.C. 791a et seq.] any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

(1) Judicial review may be obtained respecting any proceeding conducted by a State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) in the same manner, and under the same requirements, as judicial review may be

obtained under section 2633 of this title in the case of a proceeding to which section 2633 of this title applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f). Any such action shall be brought only in the manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 U.S.C. 824 et seq.], such rule shall be treated as a rule under the Federal Power Act [16 U.S.C. 791a et seq.]. Nothing in subsection (g) shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) shall be treated as a rule enforceable under the Federal Power Act [16 U.S.C. 791a et seq.]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) [3] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) as provided in subparagraph (A) of this paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) New dams and diversions

Except for a hydroelectric project located at a Government dam (as defined in section 3(10) of the Federal Power Act [16 U.S.C. 796(10)]) at which non-Federal hydroelectric development is permissible, this section shall not apply to any hydroelectric project which impounds or diverts the water of a natural watercourse by means of a new dam or diversion unless the project meets each of the following requirements:

(1) No substantial adverse effects

At the time of issuance of the license or exemption for the project, the Commission finds that the project will not have substantial adverse effects on the environment, including recreation and water quality. Such finding shall be made by the Commission after taking into consideration terms and conditions imposed under either paragraph (3) of this subsection or section 10 of the Federal Power Act [16 U.S.C. 803] (whichever is appropriate as required by that Act [16 U.S.C. 791a et seq.] or the Electric Consumers Protection Act of 1986) and compliance with other environmental requirements applicable to the project.

(2) Protected rivers

At the time the application for a license or exemption for the project is accepted by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to environmental consultation), such project is not located on either of the following:

(A) Any segment of a natural watercourse which is included in (or designated for potential inclusion in) a State or national wild and scenic river system.

(B) Any segment of a natural watercourse which the State has determined, in accordance with applicable State law, to possess unique natural, recreational, cultural, or scenic attributes which would be adversely affected by hydroelectric development.

(3) Fish and wildlife terms and conditions

The project meets the terms and conditions set by fish and wildlife agencies under the same procedures as provided for under section 30(c) of the Federal Power Act [16 U.S.C. 823a(c)].

(k) "New dam or diversion" defined

For purposes of this section, the term "new dam or diversion" means a dam or diversion which requires, for purposes of installing any hydroelectric power project, any construction, or enlargement of any impoundment or diversion structure (other than repairs or reconstruction or the addition of flashboards or similar adjustable devices) [4]

(l) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 U.S.C. 796(17), (18)].

(m) Termination of mandatory purchase and sale requirements

(1) Obligation to purchase

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—

(A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B)(i) transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful

opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

(2) Revised purchase and sale obligation for new facilities

(A) After August 8, 2005, no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).

(B) For the purposes of this paragraph, the term "existing qualifying cogeneration facility" means a facility that—

(i) was a qualifying cogeneration facility on August 8, 2005; or

(ii) had filed with the Commission a notice of self-certification, self recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection (n).

(3) Commission review

Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) have been met.

(4) Reinstatement of obligation to purchase

At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in subparagraph (A), (B), or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

(5) Obligation to sell

After August 8, 2005, no electric utility shall be required to enter into a new contract or obligation to sell electric energy to a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that—

(A) competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(B) the electric utility is not required by State law to sell electric energy in its service territory.

(6) No effect on existing rights and remedies

Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-

regulated electric utility on August 8, 2005, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

(7) Recovery of costs

(A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase.

(B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a et seq.).

(n) Rulemaking for new qualifying facilities

(1)(A) Not later than 180 days after August 8, 2005, the Commission shall issue a rule revising the criteria in 18 CFR 292.205 for new qualifying cogeneration facilities seeking to sell electric energy pursuant to this section to ensure—

(i) that the thermal energy output of a new qualifying cogeneration facility is used in a productive and beneficial manner;

(ii) the electrical, thermal, and chemical output of the cogeneration facility is used fundamentally for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, taking into account technological, efficiency, economic, and variable thermal energy requirements, as well as State laws applicable to sales of electric energy from a qualifying facility to its host facility; and

(iii) continuing progress in the development of efficient electric energy generating technology.

(B) The rule issued pursuant to paragraph (1)(A) of this subsection shall be applicable only to facilities that seek to sell electric energy pursuant to this section. For all other purposes, except as specifically provided in subsection (m)(2)(A), qualifying facility status shall be determined in accordance with the rules and regulations of this Act.

(2) Notwithstanding rule revisions under paragraph (1), the Commission's criteria for qualifying cogeneration facilities in effect prior to the date on which the Commission issues the final rule required by paragraph (1) shall continue to apply to any cogeneration facility that—

(A) was a qualifying cogeneration facility on August 8, 2005, or

(B) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by paragraph (1).

(Pub. L. 95–617, title II, §210, Nov. 9, 1978, 92 Stat. 3144; Pub. L. 96–294, title VI, §643(b), June 30, 1980, 94 Stat. 770; Pub. L. 99–495, §8(a), Oct. 16, 1986, 100 Stat. 1249; Pub. L. 101–575, §2, Nov. 15, 1990, 104 Stat. 2834; Pub. L. 109–58, title XII, §1253(a), Aug. 8, 2005, 119 Stat. 967.)

REFERENCES IN TEXT

The Federal Power Act, referred to in subsecs. (e), (h), (j)(1), and (m)(7)(B), is act June 10, 1920, ch. 285, 41 Stat. 1063, as amended, which is classified generally to this chapter (§791a et seq.). Part I of the Federal Power Act is classified generally to subchapter I (§791a et seq.) of this chapter. Part II of the Federal Power Act is classified generally to this subchapter (§824 et seq.). For complete classification of this Act to the Code, see section 791a of this title and Tables.

The Public Utility Holding Company Act, referred to in subsec. (e), probably means the Public Utility Holding Company Act of 1935, title I of act Aug. 26, 1935, ch. 687, 49 Stat. 803, as amended, which was classified generally to chapter 2C (§79 et seq.) of Title 15, Commerce and Trade, prior to repeal by Pub. L.

109–58, title XII, §1263, Aug. 8, 2005, 119 Stat. 974. For complete classification of this Act to the Code, see Tables.

The Electric Consumers Protection Act of 1986, referred to in subsec. (j)(1), is Pub. L. 99–495, Oct. 16, 1986, 100 Stat. 1243. For complete classification of this Act to the Code, see Short Title of 1986 Amendment note set out under section 791a of this title and Tables.

This Act, referred to in subsecs. (m)(6) and (n)(1)(B), is Pub. L. 95–617, Nov. 9, 1978, 92 Stat. 3117, as amended, known as the Public Utility Regulatory Policies Act of 1978. For complete classification of this Act to the Code, see Short Title note set out under section 2601 of this title and Tables.

CODIFICATION

Section was enacted as part of the Public Utility Regulatory Policies Act of 1978, and not as part of the Federal Power Act which generally comprises this chapter.

August 8, 2005, referred to in subsec. (n)(1)(A), was in the original "the date of enactment of this section", which was translated as meaning the date of enactment of Pub. L. 109–58, which enacted subsecs. (m) and (n) of this section, to reflect the probable intent of Congress.

AMENDMENTS

2005—Subsecs. (m), (n). Pub. L. 109–58 added subsecs. (m) and (n).

1990—Subsec. (e)(2). Pub. L. 101–575 inserted "(other than a qualifying small power production facility which is an eligible solar, wind, waste, or geothermal facility as defined in section 3(17)(E) of the Federal Power Act)" after first reference to "facility".

1986—Subsecs. (j) to (l). Pub. L. 99–495 added subsecs. (j) and (k) and redesignated former subsec. (j) as (l).

1980—Subsec. (a). Pub. L. 96–294, §643(b)(1), inserted provisions relating to encouragement of geothermal small power production facilities.

Subsec. (e)(1). Pub. L. 96–294, §643(b)(2), inserted provisions relating to applicability to geothermal small power production facilities.

Subsec. (e)(2). Pub. L. 96–294, §643(b)(3), inserted provisions respecting a qualifying small power production facility using geothermal energy as the primary energy source.

EFFECTIVE DATE OF 1986 AMENDMENT

Pub. L. 99–495, §8(b), Oct. 16, 1986, 100 Stat. 1250, provided that:

"(1) Subsection (j) of section 210 of the Public Utility Regulatory Policies Act of 1978 (as amended by subsection (a) of this section) [16 U.S.C. 824a–3(j)] shall apply to any project for which benefits under section 210 of the Public Utility Regulatory Policies Act of 1978 are sought and for which a license or exemption is issued by the Federal Energy Regulatory Commission after the enactment of this Act [Oct. 16, 1986], except as otherwise provided in paragraph (2), (3) or (4) of this subsection.

"(2) Subsection (j) shall not apply to the project if the application for license or exemption for the project was filed, and accepted for filing by the Commission, before the enactment of this Act [Oct. 16, 1986].

"(3) Paragraphs (1) and (3) of such subsection (j) shall not apply if the application for the license or exemption for the project was filed before the enactment of this Act [Oct. 16, 1986] and accepted for filing by the Commission (in accordance with the Commission's regulations and procedures in effect on January 1, 1986, including those relating to the requirement for environmental consultation) within 3 years after such enactment.

"(4)(A) Paragraph (3) of subsection (j) shall not apply for projects where the license or exemption application was filed after enactment of this Act [Oct. 16, 1986] if, based on a petition filed by the applicant for such project within 18 months after such enactment, the Commission determines (after public notice and opportunity for public comment of at least 45 days) that the applicant has demonstrated that he had committed (prior to the enactment of this Act) substantial monetary resources directly related to the development of the project and to the diligent and timely completion of all requirements of the Commission for filing an acceptable application for license or exemption. Such petition shall be publicly available and shall be filed in such form as the Commission shall require by rule issued within 120 days after the enactment of this Act. The public notice required under this subparagraph shall include written notice by the petitioner to affected Federal and State agencies.

"(B) In the case of any petition referred to in subparagraph (A), if the applicant had a preliminary permit and had completed environmental consultations (required by Commission regulations and procedures in effect

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on January 1, 1986) prior to enactment, there shall be a rebuttable presumption that such applicant had committed substantial monetary resources prior to enactment.

"(C) The applicant for a license or exemption for a project described in subparagraph (A) may petition the Commission for an initial determination under paragraph (1) of section 210(j) of the Public Utility Regulatory Policies Act of 1978 [16 U.S.C. 824a–3(j)(1)] prior to the time the license or exemption is issued. If the Commission initially finds that the project will have substantial adverse effects on the environment within the meaning of such paragraph (1), prior to making a final finding under that paragraph the Commission shall afford the applicant a reasonable opportunity to provide for mitigation of such adverse effects. The Commission shall make a final finding under such paragraph (1) at the time the license or exemption is issued. If the Federal Energy Regulatory Commission has notified the State of its initial finding and the State has not taken any action described in paragraph (2) of section 210(j) before such final finding, the failure to take such action shall be the basis for a rebuttable presumption that there is not a substantial adverse effect on the environment related to natural, recreational, cultural, or scenic attributes for purposes of such finding.

"(D) If a petition under subparagraph (A) is denied, all provisions of section 210(j) of the Public Utility Regulatory Policies Act of 1978 [16 U.S.C. 824a–3(j)] shall apply to the project regardless of when the license or exemption is issued."

Amendment by Pub. L. 99–495 effective with respect to each license, permit, or exemption issued under this chapter after Oct. 16, 1986, see section 18 of Pub. L. 99–495, set out as a note under section 797 of this title.

CALCULATION OF AVOIDED COST

Pub. L. 102–486, title XIII, §1335, Oct. 24, 1992, 106 Stat. 2984, provided that: "Nothing in section 210 of the Public Utility Regulatory Policies Act of 1978 (Public Law 95–617) [16 U.S.C. 824a–3] requires a State regulatory authority or nonregulated electric utility to treat a cost reasonably identified to be incurred or to have been incurred in the construction or operation of a facility or a project which has been selected by the Department of Energy and provided Federal funding pursuant to the Clean Coal Program authorized by Public Law 98–473 [see Tables for classification] as an incremental cost of alternative electric energy."

APPLICABILITY OF 1980 AMENDMENT TO FACILITIES USING SOLAR ENERGY AS PRIMARY ENERGY SOURCE

Pub. L. 100–202, §101(d) [title III, §310], Dec. 22, 1987, 101 Stat. 1329–104, 1329–126, provided that:

"(a) The amendments made by section 643(b) of the Energy Security Act (Public Law 96–294) [amending this section] and any regulations issued to implement such amendment shall apply to qualifying small power production facilities (as such term is defined in the Federal Power Act [16 U.S.C. 791a et seq.]) using solar energy as the primary energy source to the same extent such amendments and regulations apply to qualifying small power production facilities using geothermal energy as the primary energy source, except that nothing in this Act [see Tables for classification] shall preclude the Federal Energy Regulatory Commission from revising its regulations to limit the availability of exemptions authorized under this Act as it determines to be required in the public interest and consistent with its obligations and duties under section 210 of the Public Utility Regulatory Policies Act of 1978 [this section].

"(b) The provisions of subsection (a) shall apply to a facility using solar energy as the primary energy source only if either of the following is submitted to the Federal Energy Regulatory Commission during the two-year period beginning on the date of enactment of this Act [Dec. 22, 1987]:

"(1) An application for certification of the facility as a qualifying small power production facility.

"(2) Notice that the facility meets the requirements for qualification."

STUDY AND REPORT TO CONGRESSIONAL COMMITTEES ON APPLICATION OF PROVISIONS RELATING TO COGENERATION, SMALL POWER PRODUCTION, AND INTERCONNECTION AUTHORITY TO HYDROELECTRIC POWER FACILITIES

Pub. L. 99–495, §8(d), Oct. 16, 1986, 100 Stat. 1251, provided that:

"(1) The Commission shall conduct a study (in accordance with section 102(2)(C) of the National Environmental Policy Act of 1969 [42 U.S.C. 4332(2)(C)]) of whether the benefits of section 210 of the Public Utility Regulatory Policies Act of 1978 [16 U.S.C. 824a–3] and section 210 of the Federal Power Act [16 U.S.C. 824i] should be applied to hydroelectric power facilities utilizing new dams or diversions (within the meaning of section 210(k) of the Public Utility Regulatory Policies Act of 1978).

"(2) The study under this subsection shall take into consideration the need for such new dams or diversions for power purposes, the environmental impacts of such new dams and diversions (both with and without the

application of the amendments made by this Act to sections 4, 10, and 30 of the Federal Power Act [16 U.S.C. 797, 803, 823a] and section 210 of the Public Utility Regulatory Policies Act of 1978 [16 U.S.C. 824a–3]), the environmental effects of such facilities alone and in combination with other existing or proposed dams or diversions on the same waterway, the intent of Congress to encourage and give priority to the application of section 210 of Public Utility Regulatory Policies Act of 1978 to existing dams and diversions rather than such new dams or diversions, and the impact of such section 210 on the rates paid by electric power consumers.

"(3) The study under this subsection shall be initiated within 3 months after enactment of this Act [Oct. 16, 1986] and completed as promptly as practicable.

"(4) A report containing the results of the study conducted under this subsection shall be submitted to the Committee on Energy and Commerce of the United States House of Representatives and the Committee on Energy and Natural Resources of the United States Senate while both Houses are in session.

"(5) The report submitted under paragraph (4) shall include a determination (and the basis thereof) by the Commission, based on the study and a public hearing and subject to review under section 313(b) of the Federal Power Act [16 U.S.C. 825l(b)], whether any of the benefits referred to in paragraph (1) should be available for such facilities and whether applications for preliminary permits (or licenses where no preliminary permit has been issued) for such small power production facilities utilizing new dams or diversions should be accepted by the Commission after the moratorium period specified in subsection (e). The report shall include such other administrative and legislative recommendations as the Commission deems appropriate.

"(6) If the study under this subsection has not been completed within 18 months after its initiation, the Commission shall notify the Committees referred to in paragraph (4) of the reasons for the delay and specify a date when it will be completed and a report submitted."

MORATORIUM ON APPLICATION OF THIS SECTION TO NEW DAMS

Pub. L. 99–495, §8(e), Oct. 16, 1986, 100 Stat. 1251, provided that: "Notwithstanding the amendments made by subsection (a) of this section [amending section 824a–3 of this title], in the case of a project for which a license or exemption is issued after the enactment of this Act [Oct. 16, 1986], section 210 of the Public Utility Regulatory Policies Act of 1978 [16 U.S.C. 824a–3] shall not apply during the moratorium period if the project utilizes a new dam or diversion (as defined in section 210(k) of such Act) unless the project is either—

"(1) a project located at a Government dam (as defined in section 3(10) of the Federal Power Act [16 U.S.C. 796(10)]) at which non-Federal hydroelectric development is permissible, or

"(2) a project described in paragraphs (2), (3), or (4) of subsection (b) [set out as a note above].

For purposes of this subsection, the term 'moratorium period' means the period beginning on the date of the enactment of this Act and ending at the expiration of the first full session of Congress after the session during which the report under subsection (d) [set out as a note above] has been submitted to the Congress."

DEFINITIONS

For definitions of terms used in this section, see section 2602 of this title.

[1] So in original. Probably should be followed by a comma.

[2] See References in Text note below.

[3] So in original. Probably should be followed by a comma.

[4] So in original. Probably should be followed by a period.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 60

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-60. Reference the Companies' responses to AG DR 1-36, 1-48, 1-51, 1-52, and the Companies' numerous other responses to data requests regarding Certificates of Public Convenience and Necessity ("CPCN").

    a. Explain what changes the Companies have made to its internal analysis regarding CPCN's since the Commission's June 22 Order in Case No. 2016-00371, finding that the Bullitt County Pipeline was not in the ordinary course of business and that "construction should be the subject of a CPCN finding."

    b. Confirm that the Bullitt County Pipeline is a 10-12 mile, 12-inch planned pipeline, with a preliminary cost estimate of $27.6M.

    c. Provide the Companies' threshold for materiality regarding a project's impact and capital outlay.

A-60.

    a. See the response to PSC 3-20.

    b. As described in the testimony of Mr. Bellar on page 60 beginning at line 9, the Bullitt County Pipeline "will be approximately 10-12 miles long" with a nominal 12-inch diameter, and with a current budgeted cost of $38.7 million.

    c. See the response to PSC 3-20.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 61

Responding Witness: Christopher M. Garrett

Q-61. Reference the responses to AG DR 1-92 and AG DR 1-93. Explain whether the Companies have any support that in reference to the portion of the invoices noting that 13% of regular membership dues, and 24% of dues relate to "influencing legislation," that EEI equates "influencing legislation" with the entirety of the definition of "covered activities," as defined in AG DR 1-90.

A-61. Beginning in 2007, EEI no longer prepared the breakout of activities by NARUC category as provided in the 2003 rate case. The "NARUC Reporting Requirement" document provided in response to PSC 3-44 and PSC 3-40 in Case Nos. 2003-00433 and 2003-00434 appears to have been developed by NARUC's "Committee on Utility Association Oversight," which was dissolved in 2001. EEI's calculation of the percentages that are considered "influencing legislation" now are based upon the Lobbying Disclosure Act (LDA) Lobbying Report and the IRS Form 990. In calculating the lobbying percentages EEI applies a broader definition than is contained in the LDA, but that is consistent with Section 6033(b)8 of the Internal Revenue Code, which covers contact with federal, state, and local officials, as well as grassroots lobbying.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 62

Responding Witness: Christopher M. Garrett

Q-62. Reference the responses to AG DR 1-90 through AG DR 1-108. Confirm that although EEI's invoices acknowledge EEI engages in activities associated with "influencing legislation," the EEI invoices attached to the response to AG DR 1-98 do not indicate the amounts dedicated to: (i) legislative advocacy; (ii) regulatory advocacy; and (iii) public relations.

    a. Provide the amounts of the Companies EEI dues dedicated or related to: (i) legislative advocacy; (ii) regulatory advocacy; and (iii) public relations.

A-62.
    a. See response to Question No. 61.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 63

Responding Witness: David S. Sinclair

Q-63. Reference the Commission's order dated May 16, 1984 in Case No. 8924,[7] at pp. 43, wherein the Commission placed the following conditions on LG&E's membership in EPRI:

"At this time, LG&E has not performed a definitive cost-benefit analysis regarding its potential membership in EPRI. Absent such an analysis, the Commission is limited as to the response it can give Mr. Royer concerning this matter. However, LG&E is hereby apprised that should it decide to become a member of EPRI it will bear the burden in future cases of justifying the cost of its membership. To do so, LG&E must present clear documentation of the benefits available through membership, its utilization of these benefits and its inability to obtain such benefits at a lower cost. The Commission is also concerned that a substantial portion of EPRI's research concerns nuclear power which is of no direct concern in Kentucky. In future cases, should it decide to join EPRI, LG&E must document whether it could receive all nonnuclear related benefits if it reduced its dues by the portion related to nuclear research. The Commission wishes to emphasize that these are the conditions LG&E must meet should it decide to become a member of EPRI.[8] These conditions in no way represent a prior endorsement of such membership."

a. Provide copies of any and all cost-benefit analyses the Companies have prepared pertaining to their membership in EPRI for the past five (5) years.

b. Provide a breakdown of the amount of LG&E-KU dues paid to EPRI which are related to nuclear energy generation.

c. Have LG&E-KU attempted to reduce the dues they seek to recover from ratepayers by the proportion of the dues they pay to EPRI which relate to nuclear energy generation? If so, provide that sum. If they have not attempted to reduce the dues they pay, explain in full why not.

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[7] In Re: General Adjustment in Electric and Gas Rates of Louisville Gas & Electric Co.
[8] Emphasis in original.

A-63.

    a.   Although no formal cost-benefit analyses have been prepared pertaining to the Companies' membership in EPRI during the past five years, the Companies do conduct annual evaluations of each EPRI program based on its potential to bring value to customers to determine whether future participation is warranted. EPRI research brings value to ratepayers by promoting environmental protection and reduces costs by training staff to improve fuel efficiency, reduce operations and maintenance costs, and avoid future capital expenditures. Topics addressed by EPRI programs in which the Companies invest include Air Quality; Water Quality; Integrated Environmental Controls; Heat Rate Improvement; Cyber Security; and Boiler Life and Availability Improvement.

EPRI also provides collaborative leverage on the Companies' investment of approximately 20 to 1. By partnering with utilities across the country in EPRI research programs, the companies gain access to about $70 million in research value for their roughly $3.5 million investment. Many EPRI research projects are operationalized. The Companies were recently awarded an EPRI Tech Transfer Award for demonstrating at the Ghent Station the ability to run a generating unit at a lower load than the manufacturer's recommended operating point while continuing to utilize the selective catalytic reduction to reduce nitrous oxide emissions.

The Companies also note the Commission's long-standing interest in seeing research and development investments be maintained, including through larger organizations:

> The Applicants state that they will continue funding research and development ("R&D") programs as long as the programs produce benefits. The Commission concurs with this position because such programs produce a myriad of benefits, including advances in fuel and generation technology, environmental technology, and transmission grid technologies. However, many new technologies take several years to develop and successfully implement. Thus, the Commission is concerned that as electricity prices become more competitive, utilities will intensify cost cutting efforts and reduce spending on R&D. Reducing R&D spending would be short-sighted and not in the customers' long-term interest.
>
> The Commission strongly supports research and development and commends the Applicants for their commitments to such programs. Benefits can be realized whether research is sponsored solely by one utility or through a larger organization funded by multiple utilities or stakeholders. The benefits of

R&D may well help the Applicants in fulfilling their commitments to preserve LG&E's and KU's low rates and high quality service.

To assist the Commission in its efforts to monitor this commitment, the Applicants should provide written notice of any material changes in their level of participation or funding for R&D 30 days prior to the proposed change. This includes any change in R&D funding equal to or greater than 5 percent of the previous year's budget. The written notice should include an explanation and justification for the change in policy.[9]

The Commission's final order in the Companies' most recent change of control proceeding explicitly continues the requirement for the Companies to notify the Commission of any material (equal to greater than 5%) change in research and development funding from year to year for each of the Companies.[10]

b. The Companies do not fund EPRI research related to nuclear energy generation.

c. Not applicable.

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[9] *In the Matter of: Joint Application of Powergen PLC, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of a Merger*, Case No. 2000-00095, Order at 34-35 (May 15, 2000).

[10] *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON U.S. Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities*, Case No. 2010-00204, Order at Appx. C page 8 (Sept. 30, 2010).

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 64

Responding Witness: Lonnie E. Bellar

Q-64. State whether EEI utilizes any of the dues the Companies pay to it for any purposes relating to nuclear power generation. If so, provide an estimate of the amount or percentage of those dues.

A-64. The Companies are not aware if EEI utilizes any of the dues paid by the Company for purposes relating to nuclear power generation. The annual dues calculation is based on a combination of specific customer, revenue and generation data for the Companies, none of which are related to nuclear power generation.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 65

Responding Witness: Lonnie E. Bellar

Q-65. Provide the Companies' most recent cost-benefit analysis regarding its membership in EEI.

A-65. The Companies have not performed formal cost-benefit analyses specific to membership in EEI. The Company does periodically do a thorough internal review of our participation and engagement in EEI and the value derived from membership activities. The Company strongly believes there are significant benefits achieved in the collaboration with other utilities in the areas of best practices, industry information and networking. Furthermore, EEI membership provides the Company with the opportunity to learn and share relevant industry information with peer utilities. More specifically, EEI provides programs that directly support the Companies and the reliability and resilience of the electric power system including:

- Mutual Assistance: EEI companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted.
- Spare Transformer Equipment Program (STEP): This is an electric industry program that strengthens the sector's ability to restore the nation's transmission system more quickly in the event of a terrorist attack. STEP represents a coordinated approach to increasing the electric power industry's inventory of spare transformers and streamlining the process of transferring those transformers to affected companies in the event of a transmission outage caused by a terrorist attack
- SpareConnect: This program provides an additional mechanism for utilities to network with other participants concerning the possible sharing of transmission and generation step-up (GSU) transformers and related equipment, including bushings, fans and auxiliary components. SpareConnect establishes a confidential, unified platform for the entire electric industry to communicate equipment needs in the event of an emergency or other non-routine failure.
- Additionally, EEI supports several initiatives to safeguard the energy grid from threats and is partnering with federal agencies to improve sector-wide resilience to cyber and physical threats.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 66

Responding Witness: Christopher M. Garrett

Q-66. Reference the response to AG DR 1-98, attachment.

    a. Confirm that the attachment is missing page 1 of 2 of the invoice from EPRI dated Jan. 18, 2018. Provide the first page of that invoice.

    b. State whether the Southern Gas Association engages in "covered activities," as defined in AG DR 1-90.

    c. State whether the Kentucky Gas Association engages in "covered activities."

A-66.
    a.   Confirmed, see attached.

    b.   The Company is not aware of any engagement in "covered activities."

    c.   The Company is not aware of any engagement in "covered activities."

EPRI ELECTRIC POWER RESEARCH INSTITUTE

INVOICE

Invoice:	90022357
Invoice Date:	01/18/2018
Page:	1 of 2

P.O. Box 10412
Palo Alto CA 94303-0813
USA

Customer: David Link
LG&E and KU Energy LLC
220 W Main St
Louisville KY 40202-1395
USA

Customer No:	30166
Payment Terms:	EPRI - Net due in 30 days
Due Date:	02/17/2018
Customer Ref:	
EPRI Quotation No:	20008283

For billing questions, please contact:

Telephone:	650-855-2048
Fax:	650-855-2358
Email:	accountsreceivable@epri.com

AMOUNT DUE: **3,455,281.35 USD**

Line	Description	Quantity	UOM	Net Amount
1	Integrated Environmental Controls	1	EA	554,913.85
2	Continuous Emissions Monitoring	1	EA	109,115.36
3	Heat Rate Improvement	1	EA	88,722.02
4	Water Management Technology	1	EA	165,280.42
5	Boiler Life and Availability Improvement	1	EA	175,796.40
6	Steam Turbines-Generators and Auxiliary Systems	1	EA	139,600.78
7	Balance of Plant Systems and Equipment	1	EA	37,484.51
8	Boiler and Turbine Steam and Cycle Chemistry	1	EA	105,722.36
9	Fossil Materials and Repair	1	EA	158,280.32
10	Combined Cycle HRSG and Balance of Plant	1	EA	108,989.67
11	Maintenance Management and Technology	1	EA	145,331.73
12	Operations Management and Technology	1	EA	117,473.16
13	CO2 Capture, Utilization and Storage	1	EA	183,180.48
14	Power Plant Multimedia Emissions Characterization	1	EA	210,883.36
15	Air Pollutants and Toxics: Health Effects	1	EA	206,303.52
16	Coal Combustion Products - Environmental Issues	1	EA	168,935.68
17	Fish Protection	1	EA	131,582.83
18	Effluent Guidelines and Plant Wastewater Monitoring	1	EA	123,369.07

Please wire funds to:
Bank of America
ABA#: 026009593
Acct.No.: 1233954313
SWIFT Address: BOFAUS3N

Please remit check to:
Electric Power Research Institute
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. # 237175375
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 67

Responding Witness: John K. Wolfe

Q-67. Reference the response to AG DR 1-185. Identify the ways in which the Companies' distribution grid enhancements are making integration of distributed generation resources possible in a cost-effective manner.

　　a. Have the Companies identified any opportunities to standardize and streamline interconnection processes, and to adopt and implement interoperability standards, particularly at the distribution level?

　　b. Will any of the distribution grid improvements the Companies are currently implementing in any manner act to preclude the potential for future integration of distributed generation resources, or to make such integration more difficult? If so, provide a complete discussion.

A-67. The Companies' grid improvements aim to accommodate the integration of distributed generation in a cost effective manner by: leveraging upgrades in conductor ampacity providing higher hosting capacity opportunity; collecting real time operational data (e.g. voltage, current) through SCADA enabled field devices to further enable Distribution Management System (DMS) functions (e.g. power flow, voltage control), allowing real-time operational monitoring, control, and system planning modeling to assure system reliability; and implementation of microprocessor protection systems that provide for more flexible configurations to accommodate distributed resource installations. These investments will offset future investments that would be needed to accommodate higher levels of distributed generation resources.

　　a. The Companies continually evaluate industry best practices regarding the distributed generation application process. The Companies have found that one best practice is to implement a user friendly web-portal versus the traditional paper application process used today. This improvement is currently under evaluation. The Companies require all distributed generation interconnections to meet IEEE 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems), which contains requirements for interoperability.

　　b. No. Current improvements in the Companies' distribution systems will only help enable future distributed generation resource integration.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018

Case No. 2018-00295

Question No. 68

Responding Witness: John K. Wolfe

Q-68.   Reference the Companies' response to AG DR 1-188.

a.   Reference Bellar direct testimony exhibit LEB-5, p. 14, Table 2. State whether one or all of the terms: (i) "Distribution Automation;" (ii) "Distribution Automation Expansion;" and/or (iii) "DSCADA Expansion" include ADMS.

b.   Reference Bellar direct testimony exhibit LEB-6. State whether the term "Distribution Automation" as used in this exhibit includes ADMS.

c.   Provide a time line depicting estimated dates for the deployment of Distribution Automation technologies, including ADMS technologies.

d.   With regard to any existing distribution technology that will be replaced with Distribution Automation technologies (including ADMS), provide a calculation of current depreciation rates in Excel format with all formulas intact. Show all parameters used, and provide a source for those rates and underlying parameters. If the rates and parameters are not the same as approved in the most recent prior case, explain why not. Also, if there are any differences in the account numbers used, provide a reconciliation.

e.   State whether any of the Distribution Automation technology the Companies intend to deploy will be covered by any warranties. If so, provide the warranty period.

f.   Provide the estimated life spans of the Distribution Automation technologies the Companies intend to deploy, including ADMS.

g.   Discuss the extent (if any) to which the proposed Distribution Automation technologies and infrastructure will be capable of receiving remote downloads of firmware and/or software upgrades. Provide copies of all manufacturer's specifications in this regard.

(i) If applicable, how many such upgrades are the proposed new Distribution Automation technologies and associated infrastructure capable of receiving before the expected lifespans of the equipment will be shortened?

(ii) How many such upgrades does the company believe it will download on an annual basis?

h. State whether the hardware, firmware, software and any infrastructure associated with the Companies' proposed deployment of Distribution Automation technologies will be required to comply in any manner with the most recent release of the National Institute of Standards and Technology (NIST)'s, "NIST Framework and Roadmap for Smart Grid Interoperability Standards."

i. Will the Companies at any time prior to deploying any ADMS technology conduct any Testbed demonstrations in their service territories?

(i) Have the companies considered obtaining the Commission's permission for a pilot program of ADMS technology? If not, why not?

(ii) How can the Companies assert that their proposed distribution grid enhancements are being carried-out in a cost-effective manner if, as asserted in their response to AG DR 1-188, they have not conducted any ADMS Testbed demonstrations?

A-68.

a. "Distribution Automation" as referenced in Bellar direct testimony exhibit LEB-5, p. 14, Table 2 includes ADMS. "Distribution Automation Expansion" and "DSCADA Expansion" do not include ADMS.

b. "Distribution Automation" as used in Bellar direct testimony exhibit LEB-6 includes ADMS.

c. See attached.

d. ADMS and DSCADA do not replace existing distribution technologies. Any field equipment, such as non-electronically controlled reclosers, replaced as part of the overall DA implementation will be reconditioned if necessary and reinstalled in other locations as needed.

e. The ADMS has a warranty period of one year from the date of electronic download, which was December 14, 2018, in preparation for the 2019 go-live referenced in question A-68c above. The reclosers have a warranty period of 18 months from the date of shipment, or 12 months from date of

commissioning, whichever comes first. The recloser controls have a warranty period of ten years after shipment.

f.   Estimated life spans are ADMS – 5 years, DSCADA – 5 years, reclosers – 30 years.

g.   The recloser controls communicate using Internet Protocol (IP) and are capable of receiving remote firmware updates. See Appendix B of the attached manufacturer's specification (651R-2_IM_20180615.pdf) for details.

(i.) Not applicable.

(ii) At this time, the Company anticipates installing only critical security-related firmware updates on an as-needed basis.

h.   Compliance with NIST Framework and Roadmap for Smart Grid Interoperability Standard is not required.

i.   The companies do not plan to conduct ADMS Testbed demonstrations in their service territories prior to ADMS implementation.

(i.) As part of Case Numbers 2016-00370 and 2016-00371, the Companies obtained CPCN approval to complete their DA program, which includes implementation of ADMS technology. An ADMS pilot would amount to a subset of the program that has already been approved.

(ii.)Mr. Thompson's testimony Exhibit PWT-7 of Case Numbers 2016-00370 and 2016-00371 demonstrates the approved DA program is the lowest cost alternative for customers. Page 53 of Mr. Bellar's testimony in the current cases describes operating efficiencies enabled by DA consistent with widespread experience within the industry as referenced in AG 1-188.

Distribution Automation Technologies Timeline

2018	2019	2020	2021	2022	2023
• Recloser Installation	• Recloser Installation • DMS Go-live • PowerFlow • Fault Location Analysis • Feeder Load Management • DSCADA Go-live	• Recloser Intallation • DMS Go-live • Suggested Switching • Fault Location Isolation and Service Restoration (FLISR)	• Recloser Installation	• Recloser Installation	• Recloser Installation
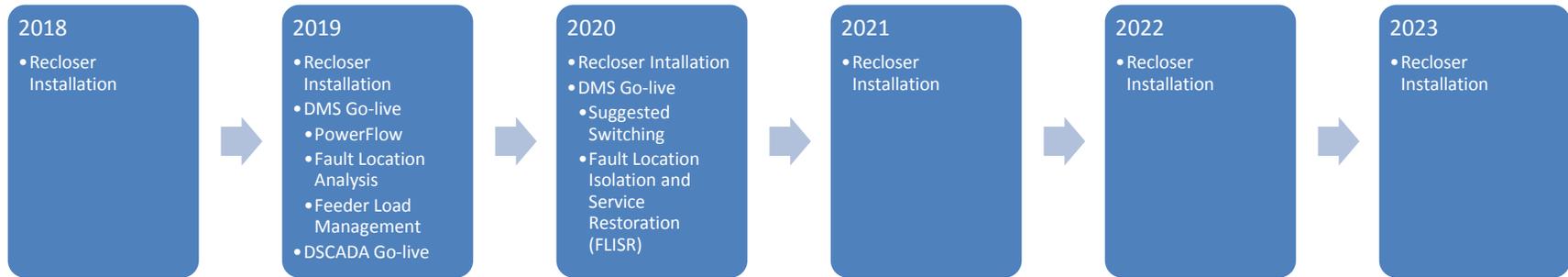
SEL-651R-2

Recloser Control

Instruction Manual

20180615

SEL SCHWEITZER ENGINEERING LABORATORIES, INC.

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Preface

Manual Overview

The SEL-651R-2 Recloser Control Instruction Manual describes common aspects of recloser control application and use. It includes the necessary information to install, set, test, and operate the relay and more detailed information about settings and commands.

An overview of each manual section and topics follows:

Preface. Describes the manual organization and conventions used to present information.

Section 1: Introduction and Specifications. Introduces SEL-651R-2 features, options, and accessories. This section also summarizes relay functions and applications; lists relay specifications, type tests, and ratings.

Section 2: Installation. Details enclosure dimensions, mounting, external cable connections, and grounding. Shows recloser control module front- and rear-panel features. Contains instructions for connecting extra I/O, communications, and 12 V auxiliary power. Explains how to access and set recloser control module main board jumpers. Describes the differences in control cable and internal cabinet wiring for the various supported reclosers.

Section 3: PC Software. Explains how to use ACSELERATOR QuickSet SEL-5030 Software.

Section 4: Protection Functions. Describes the function of various relay protection elements and how the relay processes these elements. Provides detailed specifics on protection scheme logic.

Section 5: Trip and Target Logic. Describes the factory-default tripping logic for single-phase (single-phase or three-phase tripping) and three-phase reclosers; includes switch-onto-fault logic and factory-default target logic.

Section 6: Close and Reclose Logic. Describes the factory-default close and reclose logic for single-phase and three-phase reclosers.

Section 7: SELOGIC Control Equation Programming. Describes SELOGIC control equations and how to apply these equations; discusses SELOGIC control equation features such as operands, timers, latches, counters, and analog comparisons. Explains debounce timers for recloser control inputs and extra optoisolated inputs. Details trip and close output logic and the extra programmable output contact logic.

Section 8: Metering and Monitoring. Provides information on viewing fundamental and rms metering quantities for voltages and currents, as well as power and energy metering data. Describes how to set the recloser/circuit breaker contact wear monitor and the battery monitor function.

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Section 9: Settings. Provides a list of all SEL-651R-2 settings and defaults. The organization of the settings is the same as for the settings organization in the relay and in QuickSet. Provides detailed information required to set the SEL-651R-2. It includes default settings and setting sheets.

Section 10: Communications. Explains the physical interfaces of the SEL-651R-2. Describes the various SEL software protocols and references appendices with detailed information on these protocols. Provides an alphabetical listing of all ASCII commands with examples for each ASCII command option.

Section 11: Front-Panel Operations. Describes the liquid crystal display (LCD) messages and menu screens. Shows how to use programmable front-panel targets, operator-control pushbuttons, and LEDs to provide local control.

Section 12: Analyzing Events. Explains how to obtain event summaries and history reports, obtain and interpret filtered and unfiltered event reports, obtain SER reports, and obtain SSI reports.

Section 13: Testing and Troubleshooting. Describes techniques for testing, troubleshooting, and maintaining the SEL-651R-2. Includes the list of status notification messages and a troubleshooting chart.

Appendix A: Firmware and Manual Versions. Lists the current firmware versions and details differences between the current and previous versions.

Appendix B: Firmware Upgrade Instructions. Describes the procedure to update the firmware stored in flash memory.

Appendix C: Compressed ASCII Commands. Contains a summary and description of the Compressed ASCII commands supported by the SEL-651R-2.

Appendix D: MIRRORED BITS Communications. Describes how SEL protective relays and other devices can directly exchange information quickly, securely, and with minimal cost.

Appendix E: DNP3 Communications. Describes the DNP3 communications protocol and how to apply this protocol to substation integration and automation.

Appendix F: Relay Word Bits. Contains a summary of Relay Word bits.

Appendix G: Analog Quantities. Contains a summary of analog quantities.

Appendix H: Fast SER Protocol. Describes special binary Fast Sequential Events Recorder (SER) messages.

Appendix I: Configuration, Fast Meter, and Fast Operate Commands. Contains a summary and description of the Binary Fast Meter and Fast Operate messages as well as the ASCII configuration messages supported by the SEL-651R-2.

Appendix J: Synchrophasors. Describes the C37.118 synchrophasor protocol and how to apply this protocol to monitor voltages and currents throughout the system.

Appendix K: Modbus RTU and TCP Communications. Describes the Modbus communications protocol and how to apply this protocol to substation integration and automation.

Appendix L: IEC 61850. Describes the IEC 61850 protocol and how to apply this protocol to substation integration and automation.

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Appendix M: Cybersecurity Features. Describes the mechanisms within the SEL-651R-2 for managing electronic access.

SEL-651R-2 Recloser Control Command Summary. Briefly describes the communications port commands that are fully described in *Section 10: Communications*.

Safety Information

Dangers, Warnings, and Cautions

This manual uses three kinds of hazard statements, defined as follows:

⚠ **DANGER**
Indicates an imminently hazardous situation that, if not avoided, **will** result in death or serious injury.

⚠ **WARNING**
Indicates a potentially hazardous situation that, if not avoided, **could** result in death or serious injury.

⚠ **CAUTION**
Indicates a potentially hazardous situation that, if not avoided, **may** result in minor or moderate injury or equipment damage.

Safety Symbols

The following symbols are often marked on SEL products.

⚠	⚠ **CAUTION** Refer to accompanying documents.	⚠ **ATTENTION** Se reporter à la documentation.
⏚	Earth (ground)	Terre
⏚	Protective earth (ground)	Terre de protection
⎓	Direct current	Courant continu
∿	Alternating current	Courant alternatif
∿	Both direct and alternating current	Courant continu et alternatif
📖	Instruction manual	Manuel d'instructions

Other Safety Marks (Sheet 1 of 3)

⚠ **DANGER** Disconnect or de-energize all external connections before opening this device. Contact with hazardous voltages and currents inside this device can cause electrical shock resulting in injury or death.	⚠ **DANGER** Débrancher tous les raccordements externes avant d'ouvrir cet appareil. Tout contact avec des tensions ou courants internes à l'appareil peut causer un choc électrique pouvant entraîner des blessures ou la mort.
⚠ **DANGER** Do not access/move jumpers while the unit is powered up.	⚠ **DANGER** Ne pas accéder aux cavaliers ou les changer quand l'unité est sous tension.

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Other Safety Marks (Sheet 2 of 3)

⚠**DANGER**

If the recloser is energized while the control cable is disconnected from the recloser control, the CT secondaries in the control cable may generate dangerously high voltages. Do not come in contact with the pins or pin sockets in the control cable. Contact with high voltage can cause serious injury or death.

⚠**DANGER**

Si le réenclencheur est sous tension tandis que le câble de commande est débranché de la commande du réenclencheur, le secondaire des transformateurs de courant (TC) dans le câble de commande peut présenter des tensions dangereusement élevées. Ne pas toucher les broches du câble de commande. Tout contact avec une tension élevée peut entraîner des blessures graves ou la mort.

⚠**DANGER**

The removed cables for connections **J201**, **J202**, and **J205** are still energized. Contact with such terminals can cause electrical shock that can result in injury or death.

⚠**DANGER**

Les câbles retirés des raccordements **J201**, **J202** et **J205** sont encore sous tension. Le contact avec ces câbles peut causer des chocs électriques qui peuvent entraîner des blessures ou la mort.

⚠**WARNING**

Do not transport the SEL-651R-2 with the battery inside the enclosure.

⚠**AVERTISSEMENT**

Ne pas transporter le SEL-651R-2 avec la batterie à l'intérieur du coffret.

⚠**WARNING**

Have only qualified personnel service this equipment. If you are not qualified to service this equipment, you can injure yourself or others, or cause equipment damage.

⚠**AVERTISSEMENT**

Seules des personnes qualifiées peuvent travailler sur cet appareil. Si vous n'êtes pas qualifiés pour ce travail, vous pourriez vous blesser avec d'autres personnes ou endommager l'équipement.

⚠**WARNING**

Setting 79CLSD = OFF can create an indefinite "standing close" condition. This is usually not desirable in practice.

⚠**AVERTISSEMENT**

Le réglage 79CLSD=OFF peut créer une condition de commande de fermeture permanente. Cette pratique n'est normalement pas recommandée.

⚠**WARNING**

Take proper precautions to prevent personal injury or equipment damage when lifting and mounting the SEL-651R-2. Make sure doors are latched closed. Secure lifting attachments to the lifting holes. Lift slowly. Do not transport the SEL-651R-2 with the battery inside the enclosure.

⚠**AVERTISSEMENT**

Prendre les précautions appropriées pour éviter les blessures au personnel et les dommages à l'équipement quand on soulève et qu'on monte le SEL-651R-2. S'assurer que les portes sont verrouillées. Fixer les attaches sur les trous prévus pour l'élévation. Soulever lentement. Ne pas transporter le SEL-651R-2 avec la batterie dans le coffret.

⚠**WARNING**

This device is shipped with default passwords. Default passwords should be changed to private passwords at installation. Failure to change each default password to a private password may allow unauthorized access. SEL shall not be responsible for any damage resulting from unauthorized access.

⚠**AVERTISSEMENT**

Cet appareil est expédié avec des mots de passe par défaut. A l'installation, les mots de passe par défaut devront être changés pour des mots de passe confidentiels. Dans le cas contraire, un accès non-autorisé á l'équipement peut être possible. SEL décline toute responsabilité pour tout dommage résultant de cet accès non-autorisé.

⚠**CAUTION**

Disconnect the battery from the relay module (using the Quick Disconnect) before disconnecting the battery terminals and removing the battery. Connect the Quick Disconnect last when installing the battery.

⚠**ATTENTION**

Débrancher la batterie du module du relais (en utilisant le "Quick Disconnect") avant de débrancher les bornes de la batterie et ensuite retirer la batterie. Rebrancher le "Quick Disconnect" en dernier lorsqu' on replace la batterie.

⚠**CAUTION**

Do not connect the SEL-651R-2 to an energized recloser until all control settings have been properly programmed and verified. Failure to comply can result in control and recloser misoperation, equipment damage, and personal injury.

⚠**ATTENTION**

Ne pas raccorder le SEL-651R-2 à un réenclencheur sous-tension avant que tous les réglages de la commande n'aient été proprement programmés et vérifiés. Toute dérogation à cette directive peut entraîner une opération intempestive de la commande ou du réenclencheur, des dommages à l'équipement ou des blessures au personnel.

⚠**CAUTION**

Equipment components are sensitive to electrostatic discharge (ESD). Undetectable permanent damage can result if you do not use proper ESD procedures. Ground yourself, your work surface, and this equipment before removing any cover from this equipment. If your facility is not equipped to work with these components, contact SEL about returning this device and related SEL equipment for service.

⚠**ATTENTION**

Les composants de cet équipement sont sensibles aux décharges électrostatiques (DES). Des dommages permanents non-décelables peuvent résulter de l'absence de précautions contre les DES. Raccordez-vous correctement à la terre, ainsi que la surface de travail et l'appareil avant d'en retirer un panneau. Si vous n'êtes pas équipés pour travailler avec ce type de composants, contacter SEL afin de retourner l'appareil pour un service en usine.

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Other Safety Marks (Sheet 3 of 3)

⚠ CAUTION	⚠ ATTENTION
Never apply voltage signals greater than 9 V peak-peak to the low-level test interface (J14) or equipment damage may result.	Au risque de causer des dommages à l'équipement, ne jamais appliquer un signal de tension supérieur à 9 V crête à crête à l'interface de test de bas niveau (J14).
⚠ CAUTION The battery temperature sensor board contains exposed components that are sensitive to Electrostatic Discharge (ESD). When working with this board, work surfaces and personnel must be properly grounded or equipment damage may result.	⚠ ATTENTION Le capteur de température de la batterie contient des composants à découvert qui sont sensibles aux décharges électrostatiques. Lorsqu'on travaille sur cette carte, les surfaces de travail et le personnel doivent être adéquatement mis à la terre sans quoi des dommages à l'équipement pourraient survenir.
⚠ CAUTION The recloser control must be mounted on the same pole as the recloser when low-energy analog (LEA) inputs are used. This practice reduces surges that may damage the recloser control. Shielded cables are recommended when using LEA inputs.	⚠ ATTENTION La commande du réenclencheur doit être montée sur le même poteau que le réenclencheur quand des entrées analogiques de bas niveau sont utilisées. Cette pratique réduit les bruits impulsifs qui pourraient endommager les circuits de commande du réenclencheur. Des câbles blindés sont recommandés avec ce type d'entrées.
⚠ CAUTION The relay contains devices sensitive to Electrostatic Discharge (ESD). When working on the relay with the front panel removed, work surfaces and personnel must be properly grounded or equipment damage may result.	⚠ ATTENTION Le relais contient des pièces sensibles aux décharges électrostatiques. Quand on travaille sur le relais avec les panneaux avant ou du dessus enlevés, toutes les surfaces et le personnel doivent être mis à la terre convenablement pour éviter les dommages à l'équipement.
⚠ CAUTION There is danger of explosion if the battery is incorrectly replaced. Replace only with Rayovac no. BR2335 or equivalent recommended by manufacturer. See Owner's Manual for safety instructions. The battery used in this device may present a fire or chemical burn hazard if mistreated. Do not recharge, disassemble, heat above 100°C or incinerate. Dispose of used batteries according to the manufacturer's instructions. Keep battery out of reach of children.	⚠ ATTENTION Une pile remplacée incorrectement pose des risques d'explosion. Remplacez seulement avec un Rayovac no BR2335 ou un produit équivalent recommandé par le fabricant. Voir le guide d'utilisateur pour les instructions de sécurité. La pile utilisée dans cet appareil peut présenter un risque d'incendie ou de brûlure chimique si vous en faites mauvais usage. Ne pas recharger, démonter, chauffer à plus de 100°C ou incinérer. Éliminez les vieilles piles suivant les instructions du fabricant. Gardez la pile hors de la portée des enfants.

General Information

Typographic Conventions

There are four ways to communicate with the SEL-651R-2:

➤ Using a command line interface on a PC terminal emulation window.

➤ Using a command line interface through the virtual terminal interface of a DNP3 communications link.

➤ Using the front-panel menus and pushbuttons.

➤ Using QuickSet.

The instructions in this manual indicate these options with specific font and formatting attributes. The following table lists these conventions:

Example	Description
STATUS	Commands typed at a command line interface on a PC.
n **SHO** *n*	Variables determined based on an application (in bold if part of a command).
<Enter>	Single keystroke on a PC keyboard.
<Ctrl+D>	Multiple/combination keystroke on a PC keyboard.
Start > Settings	PC software dialog boxes and menu selections. The > character indicates submenus.

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Example	Description
CLOSE	Relay front-panel pushbuttons.
ENABLE	Relay front- or rear-panel labels.
MAIN > METER	Relay front-panel LCD menus and relay responses visible on the PC screen. The > character indicates submenus.
Are you sure?	Relay responses visible on the PC screen.

Examples

This instruction manual uses several example illustrations and instructions to explain how to effectively operate the SEL-651R-2. These examples are for demonstration purposes only; the firmware identification information or settings values included in these examples may not necessarily match those in the current version of your SEL-651R-2.

Trademarks

All brand or product names appearing in this document are the trademark or registered trademark of their respective holders. No SEL trademarks may be used without written permission.

SEL trademarks appearing in this manual are shown in the following table.

ACSELERATOR Analytic Assistant®	Best Choice Ground Directional Element®
ACSELERATOR Architect®	Compass®
ACSELERATOR QuickSet®	MIRRORED BITS®
ACSELERATOR TEAM®	SEL-2407®
Arc Sense™	SELOGIC®

Technical Support

We appreciate your interest in SEL products and services. If you have questions or comments, please contact us at:

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Fax: +1.509.332.7990
Internet: selinc.com/support
Email: info@selinc.com

Section 1

Introduction and Specifications

The SEL-651R-2 Recloser Control builds upon the success of the SEL-651R-0/1 Recloser Control, with new features and wider applicability. Apply the SEL-651R-2 in urban and rural distribution systems for increased system reliability. Connect the SEL-651R-2 to existing traditional reclosers and newer single-phase trip/reclose-capable reclosers, as detailed in following information.

This section introduces the SEL-651R-2 Recloser Control and provides information on the following topics:

Features

The SEL-651R-2 contains many protection, automation, and control features. *Figure 1.1* presents a simplified functional overview of the relay.

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Features

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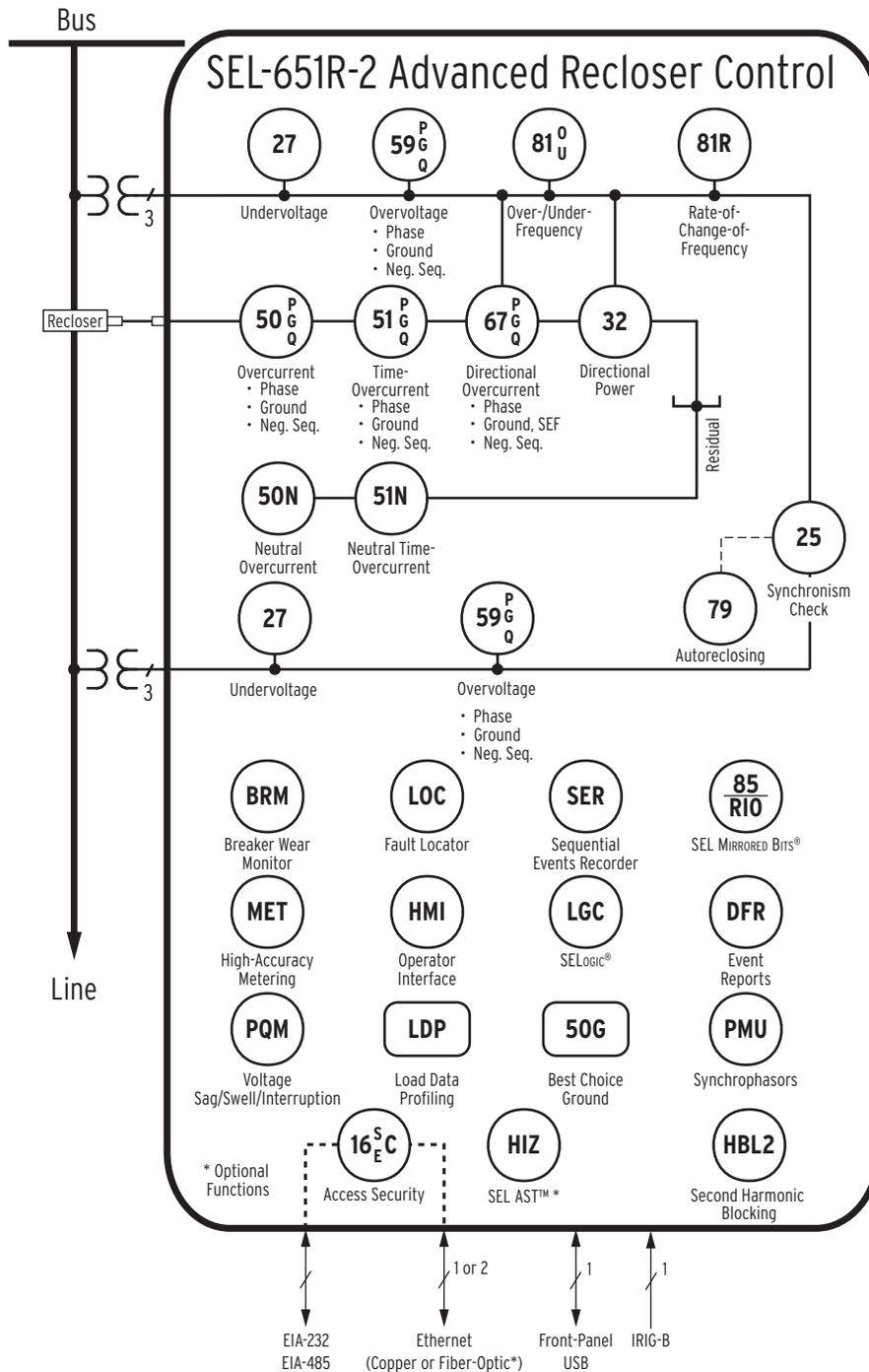
Figure 1.1   Functional Overview

Automatic Network Reconfiguration

Augment system reliability by using Automatic Network Reconfiguration to automatically isolate faulted line sections and restore service to the unaffected areas of the system. The SEL-651R-2 includes six voltage inputs to monitor both source-side and load-side voltages, ensuring safe and secure Automatic Network Reconfiguration automation. Automatic Network Reconfiguration automation is especially applicable in urban areas.

Ethernet Communication	Communicate using single fiber-optic or dual-metallic or fiber-optic Ethernet ports via DNP3, Modbus, FTP, web server, and SNTP. Firmware upgrades can also be performed through use of the Ethernet ports. The IEC 61850 protocol is available with dual copper and dual or single fiber-optic Ethernet port options. Use the Ethernet ports for local and remote engineering access, SCADA, real-time protection and control, loop restoration, islanding detection, blocking, and fast bus-tripping schemes.
Firmware Upgrade Over Web Server	Reduce firmware upgrade time and costs by uploading firmware over an Ethernet connection by using the web server interface. This feature is enabled through an Ethernet port setting with the option to require front-panel confirmation upon completion of the file being uploaded. The firmware is digitally signed and compressed. Upon upload completion, the relay verifies the signature for security.
Single-Phase Tripping/Reclosing	Reduce system and customer impacts because of faults. With single-phase tripping, interrupt only faulted phases while maintaining service to unaffected customers. Select single-phase or three-phase lockout, depending on connected loads. Single-phase operation is especially applicable in rural areas (requires a single-phase capable recloser).
PC Software	In addition to communicating and setting the relay through use of an ASCII terminal, you can use the PC-based ACSELERATOR QuickSet SEL-5030 Software to more easily configure the SEL-651R-2 and analyze fault records with relay element response.
USB Port	Use the standard front-panel USB port to speed up local communication and file transfers such as reading/writing settings and firmware upgrades.
Substantial Auxiliary Power Supply	Adequately power demanding 12 Vdc accessories with a built-in 40 W (continuous) auxiliary power supply.
Large Cabinet (Ordering Option)	Front and rear doors provide fast and easy access for front-panel operation or rear-panel connections. Large internal volume and 19" rack system allow plenty of room for accessory installation. The removable connector panel at bottom of enclosure accommodates custom hole sizes/fittings.
Extensive Recloser Compatibility (Ordering Option)	The Control Cable Interface selections in *Models and Options on page 1.4* shows the compatible reclosers. Select the desired control cable interface for the SEL-651R-2 at ordering time. Learn the setting and operation of this one recloser control and retrofit numerous existing recloser installations and equip new recloser installations.
Low-Energy Analog (LEA) Voltage Inputs (Ordering Option)	Connect the low-level voltage outputs from less-costly power system voltage transducers to three-phase LEA voltage inputs on the SEL-651R-2.

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Accessories (Ordering Option)

Order additional accessories for the SEL-651R-2, such as:

➤ 19" rack mount accessory shelf for radios, etc.

➤ Vandal sleeves to prevent cable connection tampering.

➤ Fuse blocks for voltage input and control power protection.

➤ AC transfer switch for alternate control power source switching—especially useful in Automatic Network Reconfiguration operation.

Models and Options

See the latest SEL-651R-2 Model Option Table at selinc.com.

SEL-651R Models

This instruction manual covers the SEL-651R-2 models introduced in 2012. *Table 1.1* describes distinguishing features of products covered and not covered by this manual. Use any row of the table to distinguish between recloser controls covered and not covered by this manual.

Table 1.1   SEL-651R Product Features

Distinguishing Feature	SEL-651R Recloser Controls Covered by This Instruction Manual	SEL-651R Recloser Controls Not Covered by This Instruction Manual
Model Number[a]	0651R-2	0651R-0/1
Ethernet Port(s) on Relay Module[b]	Yes	No
Serial Port +5 V Jumpers Accessible from JMP 2 3 Opening on Relay Module[b]	Yes	No
Firmware Revision Number	FID=SEL-651R-R4xx and higher	FID=SEL-651R-R3xx and lower

[a] The model numbers used in this table are derived from the SEL-651R Model Option Tables. These numbers should not be used to order an SEL-651R. To order an SEL-651R, refer to the actual Model Option Tables.
[b] See Figure 2.5 and Figure 2.9.

Recloser Compatibility

To determine the recloser interface of an SEL-651R-2, inspect the recloser control cable receptacle (see *Figure 2.34*). The part number (found on the serial number sticker inside the SEL-651R-2 enclosure) can also be checked and compared to the SEL-651R-2 Model Option Table.

Option Considerations

Consider the following options when ordering and configuring the SEL-651R-2 Recloser Control.

➤ Control Cable Interface

➢ Traditional Retrofit (14-pin)

➢ G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-pin, single-phase trip capable)

➢ ABB OVR-3/VR-3S (15 and 27 kV models) (24-pin, single-phase trip capable)

➢ G&W Control Power Viper-S or Control-Powered Eaton NOVA (19-pin)

➢ ABB Joslyn TriMod 600R (27-pin, single-phase trip capable)

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Models and Options

➢ Eaton NOVA-TS or NOVA-STS Triple-Single (26-pin, single-phase trip capable)

➢ Siemens SDR Triple-Single (40-pin, single-phase trip capable)

➢ Siemens SDR Three-Phase (40-pin)

➢ Multi-Recloser Interface (42-pin), see *Table 2.4* for compatible reclosers

➤ Enclosure Type

➢ Dual door (side mount)

➢ Single door (rear mount)

➤ Enclosure Material

➢ Painted steel

➢ Type 304 stainless steel

➤ Door Latching

➢ Three-point latch

➤ Secondary Input Voltage Ratings

➢ Two three-phase 300 Vac sets

➢ One three-phase 8 Vac LEA set
One three-phase 300 Vac set

➢ One three-phase 8 Vac LEA set
One three-phase "Lindsey SVMI LEA" set

➢ One three-phase "Eaton NOVA LEA" set
One three-phase 300 Vac set

➢ One three-phase "Eaton NOVA LEA" set
One three-phase "Lindsey SVMI LEA" set

➢ One three-phase 300 Vac set
One three-phase "Lindsey SVMI LEA" set

➢ Two three-phase 8 Vac LEA sets

➢ One three-phase 300 Vac set
One three-phase "Siemens LEA" set

➢ One three-phase "Lindsey SVMI LEA" set
One three-phase "Siemens LEA" set

➤ Extra Inputs/Outputs

➢ Seven 12 Vdc optoisolated inputs or two 125 Vdc and five 12 Vdc optoisolated inputs

➢ Eight output contacts

➤ Communications Ports/Interfaces

➢ Dual Copper Ethernet

➢ Dual or Single Fiber Ethernet

➢ IEC 61850 Protocol

➢ USB

➢ EIA-485

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Applications

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➤ Power Supply

➢ 120 Vac (includes GFCI [Ground-Fault Circuit Interrupter] outlet)

➢ 230 Vac

➢ 125 Vdc (battery charger not included)

➢ 48 Vdc (battery charger not included)

➤ Battery

➢ 12 V, 16 Ah

➢ 12 V, 40 Ah

➤ User Interface

➢ Configurable labels

➢ Tricolor LEDs

➤ Accessories

Contact the SEL factory or your local Technical Service Center for particular part number and ordering information (see *Technical Support on page 13.15*). You can also view the latest part number and ordering information on the SEL website at selinc.com.

Applications

As stated in preceding subsections, the SEL-651R-2 can be applied to:

➤ Traditional Retrofit (14-pin)

➤ G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-pin, single-phase trip capable)

➤ ABB OVR-3/VR-3S (15 and 27 kV models) (24-pin, single-phase trip capable)

➤ G&W Control Power Viper-S or Control-Powered Eaton NOVA (19-pin)

➤ ABB Joslyn TriMod 600R (27-pin, single-phase trip capable)

➤ Eaton NOVA-TS or NOVA-STS Triple-Single (26-pin, single-phase trip capable)

➤ Tavrida OSM Al_2 (32-pin, rectangular receptacle)

➤ Siemens SDR Triple-Single (40-pin, single-phase trip capable)

➤ Siemens SDR Three-Phase (40-pin)

➤ Multi-Recloser Interface (42-pin), see *Table 2.4* for compatible reclosers

Note that G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB OVR-3/VR-3S (24-pin, 15 and 27 kV models), ABB Joslyn TriMod 600R, Eaton NOVA-TS or NOVA-STS Triple-Single, Siemens SDR Triple-Single, and the Multi-Recloser Interface reclosers include single-phase trip/reclose capability. They can also include three-phase trip/reclose and combinations in between (e.g., single-phase trip/reclose and three-phase lockout).

Figure 1.2 shows principal connections to the SEL-651R-2, with full voltage connections on each side. Complete voltage connections are used in such applications as Automatic Network Reconfiguration. *Figure 1.3* shows Automatic Network Reconfiguration augmented by MIRRORED BITS communications between SEL-651R-2 Recloser Controls. Automatic Network Reconfiguration operation automatically isolates faulted line sections and restores service to the rest of the system.
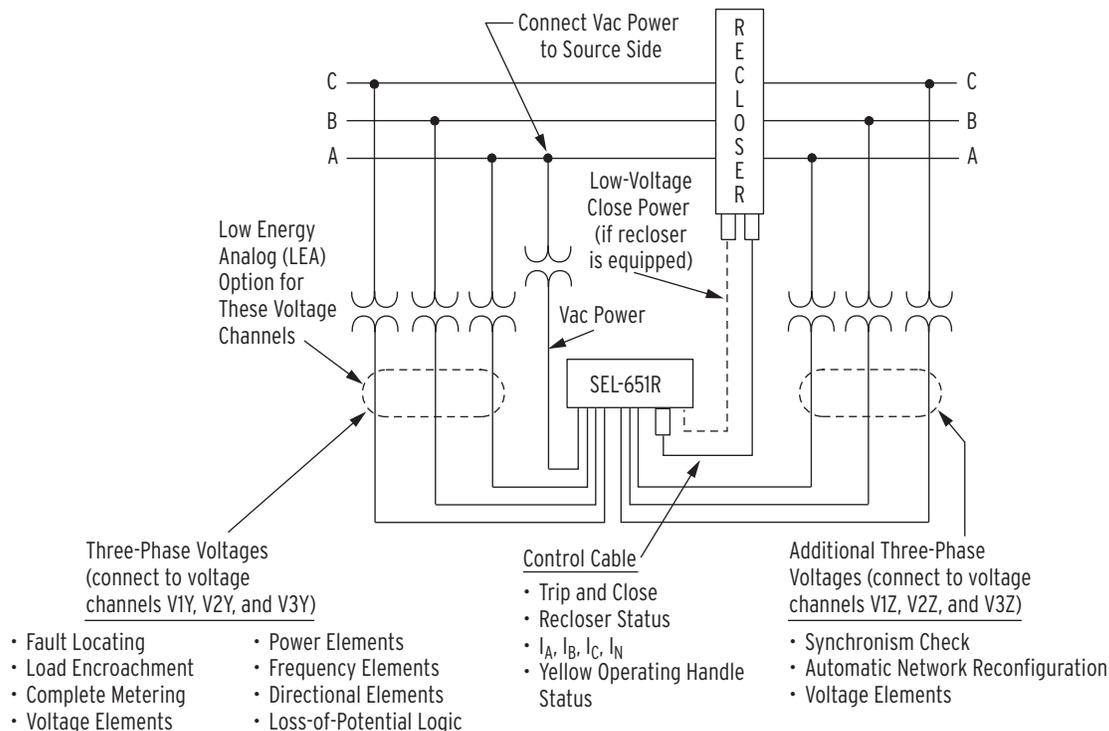
Figure 1.2   Connect Three-Phase Load and Source Voltages to SEL-651R-2

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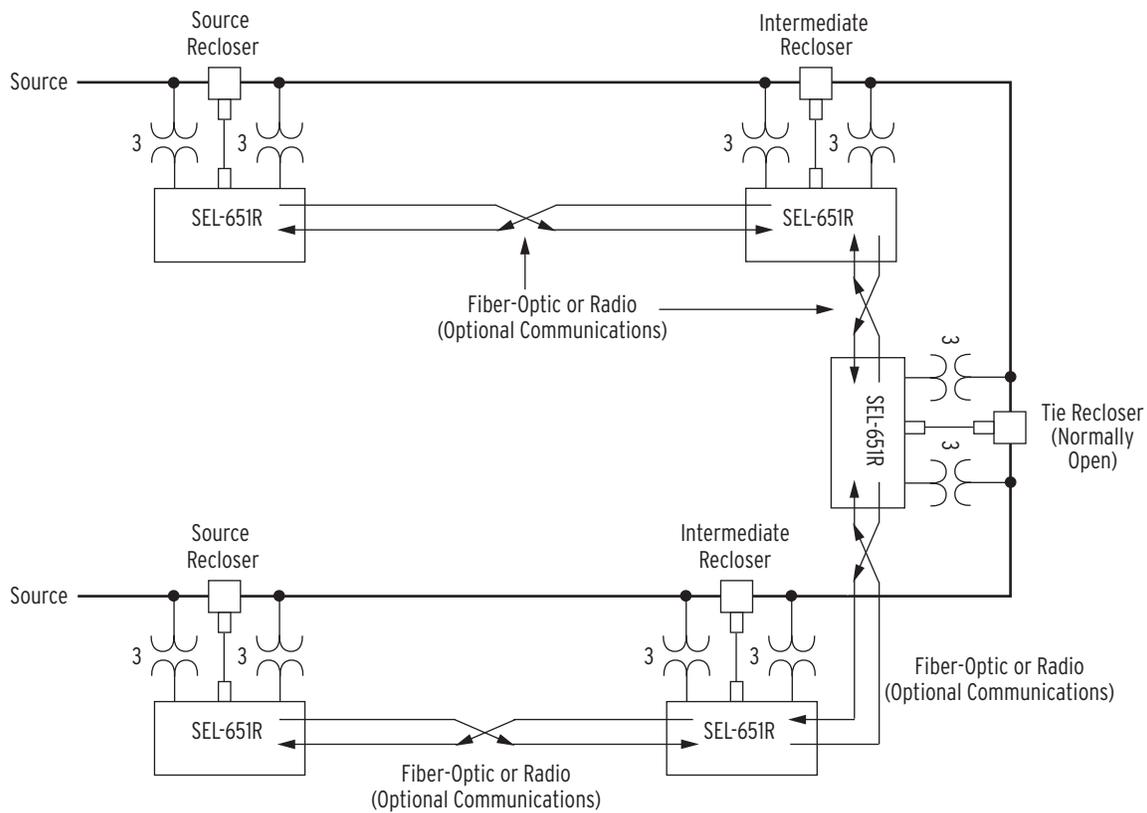
Figure 1.3   Implement Automatic Network Reconfiguration With SEL-651R-2 Recloser Controls

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Specifications

Compliance

Designed and manufactured under an ISO 9001 certified quality management system

General

AC Current Inputs

Channels IA, IB, IC

1 A Nominal:	3 A continuous (4 A continuous at 55°C), linear to 20 A symmetrical; 100 A for 1 s; 250 A for 1 cycle
Burden:	0.13 VA @ 1 A, 1.31 VA @ 3 A

Channel IN

0.2 A Nominal:	15 A continuous, linear to 5.5 A symmetrical; 500 A for 1 s; 1250 A for 1 cycle
Burden:	<0.5 VA @ 0.2 A

AC Voltage Inputs

300 V Maximum (PT):	300 V_{L-N} continuous (connect any voltage as high as 240 Vac, with allowance for surge): 600 Vac for 10 seconds
Burden:	<0.03 VA @ 67 V <0.06 VA @ 120 V <0.80 VA @ 300 V
8 V LEA Maximum:	8 V_{L-N} continuous (connect any voltage as high as 6.5 Vac, with allowance for surge): 300 Vac for 10 seconds
Burden:	Control Input Z = 1 MΩ
Common Mode Voltage	
Operation:	3 Vac
Without Damage:	50 Vac
Eaton NOVA LEA:	37 V_{L-N} continuous (connect any voltage as high as 29.6 Vac with allowance for surge): 250 Vac for 10 seconds
Burden:	Relay Input Z = 165 kΩ
Common Mode Voltage	
Operation:	3 Vac
Without Damage:	53 Vac
Lindsey SVMI LEA:	200 V_{L-N} continuous (connect any voltage as high as 160 Vac with allowance for surge): 250 Vac for 10 seconds
Burden:	Relay Input Z = 1 MΩ
Common Mode Voltage	
Operation:	3 Vac
Without Damage:	25 Vac
Siemens LEA:	8.49 V_{L-N} continuous (connect any voltage as high as 6.79 Vac with allowance for surge): 155 Vac for 10 seconds
Burden:	Relay Input Z = 24.22 kΩ
Common Mode Voltage	
Operation:	3 Vac
Without Damage:	50 Vac

Frequency and Rotation

Note: 60/50 Hz system frequency and ABC/ACB phase rotation are user-settable.

Frequency Tracking Range:	40–65 Hz
Maximum Rate of Change:	~20 Hz/s (The control will not measure faster-changing frequencies and will revert to nominal frequency if the condition is maintained for longer than 0.25 s)

Note: Voltage VnY or VnZ (where n = 1, 2, or 3) required for frequency tracking, depending upon Global setting FSELECT.

Power Supply

120 Vac Nominal

Rated Range:	85–132 Vac
Frequency Range:	40–65 Hz
Maximum Burden:	250 VA average, 500 VA peak
Inrush:	<100 A (I^2t < 24 A^2 – s)

230 Vac Nominal

Rated Range:	170–265 Vac
Frequency Range:	40–65 Hz
Maximum Burden:	250 VA average, 500 VA peak
Inrush:	<50 A (I^2t < 6 A^2 – s)

125 Vdc Nominal

Rated Range:	110.0–137.5 Vdc
Maximum Burden:	25 W continuous, 300 W for 1.5 s

48 Vdc Nominal

Rated Range:	43–60 Vdc
Maximum Burden:	25 W continuous, 300 W for 1.5 s

12 V Accessory Power Supply

For Models With AC Power Supply

12 Vdc ± 10%, 40 W continuous, 60 W for 6 s every 60 s

For Models With DC Power Supply

12 Vdc ± 10%, 3 W (0.25 A) continuous

Note: Some models momentarily dip to 9 Vdc during trip/close operations.

Output Contacts (Except Trip and Close)

Make:	30 A per IEEE C37.90-2005, Section 5.8
Carry:	6 A continuous carry at 70°C 4 A continuous carry at 85°C
1 s Rating:	50 A
MOV Protection:	270 Vac, 360 Vdc, 40 J
Pickup Time:	<5 ms
Update Rate:	1/8 cycle

Breaking Capacity (10,000 Operations):

24 V	0.75 A	L/R = 40 ms
48 V	0.50 A	L/R = 40 ms
125 V	0.30 A	L/R = 40 ms
250 V	0.20 A	L/R = 40 ms

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Cyclic Capacity (1 Cycle/Second):

24 V	0.75 A	L/R = 40 ms
48 V	0.50 A	L/R = 40 ms
125 V	0.30 A	L/R = 40 ms
250 V	0.20 A	L/R = 40 ms

Note: Per IEC 60255-0-20:1974, using the simplified assessment method.

AC Output Ratings

Maximum Operational Voltage (U_E) Rating:	240 Vac
Insulation Voltage (U_I) Rating (Excluding EN 61010-1):	300 Vac
Utilization Category:	AC-15 (control of electromagnetic loads >72 VA)
Contact Rating Designation:	B300 (B = 5 A, 300 = rated insulation voltage)
Voltage Protection Across Open Contacts:	270 Vac, 40 J
Rated Operational Current (I_E):	3 A @ 120 Vac 1.5 A @ 240 Vac
Conventional Enclosed Thermal Current (I_{THE}) Rating:	5 A
Rated Frequency:	50/60 ± 5 Hz
Electrical Durability Make VA Rating:	3600 VA, cos φ = 0.3
Electrical Durability Break VA Rating:	360 VA, cos φ = 0.3

Trip and Close Outputs

Traditional Interface Rating

Coil Voltage:	24 ± 2.4 Vdc
Coil Current:	15.5 A (Close), 12.2 A (Trip)

G&W Viper-ST\-LT, ABB Elastimold MVR, and ABB OVR/Gridshield (32-Pin and 42-Pin Versions) Rating

Coil Voltage:	155 + 5, – 3 Vdc
Coil Current:	12–17 A (Close), 4 A (Trip) (per phase)
Pulse Duration:	52–55 ms (Close), 27–30 ms (Trip)

ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Rating

Coil Voltage:	48 + 5, – 3 Vdc
Pulse Duration:	85 ms (Close), 45 ms (Trip)

Control-Powered Eaton NOVA Rating

Coil Voltage:	48 + 5, – 3 Vdc

ABB Joslyn TriMod 600R Rating

Coil Voltage:	155 + 5, – 3 Vdc
Pulse Duration:	35 ms (Close), 14 ms (Trip)

Eaton NOVA-TS or NOVA-STS Triple-Single Rating

Coil Voltage:	48 + 5, – 3 Vdc

Tavrida OSM AI_2 Rating

Coil Voltage:	155 + 5, – 3 Vdc
Pulse Duration:	60 ms (Close), 15 ms (Trip)

Tavrida OSM AI_4 Rating

Coil Voltage:	155 + 5, – 3 Vdc
Pulse Duration:	60 ms (Close), 15 ms (Trip)

Siemens SDR Triple-Single Rating

Coil Voltage:	155 + 5, – 3 Vdc
Pulse Duration:	65 ms (Close), 40 ms (Trip)

Siemens SDR Three-Phase Rating

Coil Voltage:	155 + 5, – 3 Vdc
Pulse Duration:	65 ms (Close), 40 ms (Trip)

Eaton NOVA NX-T Rating

Coil Voltage:	155 + 5, – 3 Vdc
Pulse Duration:	45 ms (Close), 10 ms (Trip)

Note: Supports an entire trip-close-trip-close-trip-close-trip-close-trip-lockout sequence every minute.

Optoisolated Inputs (Optional)

When Used With DC Control Signals

125 Vdc:	On for 105–150 Vdc; off below 75 Vdc
12 Vdc:	On for 9.6–27 Vdc

When Used With AC Control Signals

125 Vdc:	On for 89.6–150.0 Vac; off below 53.0 Vac

Note: AC mode is selectable for inputs IN101 and IN102 when ordered with 125 Vdc options via Global settings IN101D and IN102D. AC input recognition delay from time of switching: 0.75 cycles maximum pickup, 1.25 cycles maximum dropout.

Note: All optoisolated inputs draw less than 10 mA of current at nominal voltage or ac rms equivalent.

Status Inputs

DC Dropout Range:	0–4 Vdc
DC Pickup Range:	8–28 Vdc
Current Draw:	1–10 mA

Communications Ports

EIA-232:	One front, two rear
EIA-485:	One rear with 2100 Vdc of isolation
Per Port Data Rate Selections:	300, 1200, 2400, 4800, 9600, 19200, 38400, 57600
USB:	One front port (Type-B connector, CDC class device)
Ethernet:	One 10/100BASE-T rear port (RJ45 connector) (discontinued option)
	Two 10/100BASE-T rear ports optional (RJ45 connector)
	One or two 100BASE-FX rear ports optional (LC connectors multimode)
	Internal Ethernet switch included with second Ethernet port

Time-Code Inputs

Recloser Control accepts demodulated IRIG-B time-code input at Port 2 or the BNC input.

Port 2, Pin 4 Input Current:	1.8 mA typical at 4.5 V (2.5 kΩ resistive)
BNC Input Current:	4 mA typical at 4.5 V (750 Ω resistive when input voltage is greater than 2 V)

Synchronization Accuracy

Internal Clock:	±1 μs
Synchrophasor Reports (e.g., **MET PM**, **EVE P**, **CEV P**):	±10 μs
All Other Reports:	±5 ms

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Simple Network Time Protocol (SNTP) Accuracy

Internal Clock: ±5 ms

Unsynchronized Clock Drift

Control Powered: 2 minutes per year typical

Operating Temperature

Relay Module: –40° to +85°C (–40° to +185°F)

Batteries: –40° to +80°C (–40° to +176°F)

Entire SEL-651R-2: –40° to +55°C (–40° to +131°F)

Note: LCD contrast impaired for temperatures below –20°C (–4°F). The entire SEL-651R-2 unit is operationally tested to +70°C (+158°F). The 15°C (27°F) difference between the +55°C rating and +70°C is for direct sunlight temperature rise.

Weight

<114 kg (<250 lb)

Battery Specifications

Base Version Requirement

Normal Capacity: 16 amp-hours @ 25°C

Run Time (Control Electronics Operate Plus One Trip/Close Cycle): ≥9.6 hours @ +25°C
≥3.2 hours @ –40°C

Recharge Time (Deep Discharge to Fully Charged): ≤9.6 hours @ 25°C

Estimated Life: ≥4 years @ 25°C
≥1 year @ 80°C

Extended Capacity Option Requirement

Normal Capacity: 40 ampere-hours @ 25°C

Run Time (Control Electronics Operate Plus One Trip/Close Cycle): ≥24 hours @ +25°C
≥8 hours @ –40°C

Recharge Time (Deep Discharge to Fully Charged): ≤24 hours @ 25°C

Estimated Life: ≥4 years @ 25°C
≥1 year @ 80°C

Processing Specifications and Oscillography

AC Voltage and Current Inputs

128 samples per power system cycle, 3 dB low-pass filter cut-off frequency of 3 kHz.

Digital Filtering

Digital low-pass filter then decimate to 32 samples per cycle followed by one-cycle cosine filter.

Net filtering (analog plus digital) rejects dc and all harmonics greater than the fundamental.

Protection and Control Processing

Most Elements: Four times per power system cycle

Time-Overcurrent Elements: Two times per power system cycle

Oscillography

Length: 15, 30, or 60 cycles

Total Storage: 11 seconds of analog and binary

Sampling Rate: 128 samples per cycle unfiltered
32 and 16 samples per cycle unfiltered and filtered
4 samples per cycle filtered

Trigger: Programmable with Boolean expression

Format: ASCII and Compressed ASCII
Binary COMTRADE (128 samples per cycle unfiltered)

Time-Stamp Resolution: 1 µs when high-accuracy time source is connected (**EVE P** or **CEV P** commands)

Time-Stamp Accuracy: See *Time-Code Inputs* in these specifications

Sequential Events Recorder

Time-Stamp Resolution: 1 ms

Time-Stamp Accuracy (With Respect to Time Source): ±5 ms

Control Element Settings Ranges and Accuracies

Instantaneous/Definite-Time Overcurrent Elements (50)

Current Pickup Range (A Secondary)

Phase and Neg.-Seq.: 0.05–20.00 A, 0.01 A steps

Ground: 0.005–20.000 A, 0.001 A steps

Neutral: 0.005–2.500 A

Steady-State Pickup Accuracy

Phase and Neg.-Seq.: ±0.01 A plus ±3% of setting

Ground: ±0.001 A plus ±3% of setting (IN < 4.7 A)
±0.010 A plus ±3% of setting (IN ≥ 4.7 A)

Neutral: ±0.001 A plus ±3% of setting

Transient Overreach: ±5% of pickup

Pickup/Dropout Time: 1.25 cycles

Time Delay Range: 0.00–16,000.00 cycles, 0.25-cycle steps

Time Delay Accuracy: ±0.25 cycle plus ±0.1% of setting

Time-Overcurrent Elements (51)

Current Pickup Range (A Secondary)

Phase and Neg.-Seq.: 0.05–3.20 A, 0.01 A steps

Ground: 0.005–3.200 A, 0.001 A steps

Neutral: 0.005–0.640 A, 0.001 A steps

Steady-State Pickup Accuracy

Phase and Neg.-Seq.: ±0.01 A plus ±3% of setting

Ground: ±0.001 A plus ±3% of setting (IN < 4.7 A)
±0.010 A plus ±3% of setting (IN ≥ 4.7 A)

Neutral: ±0.001 A plus ±3% of setting

Time Dials

U.S.: 0.5–15.0, 0.01 steps

IEC: 0.05–1.00, 0.01 steps

Recloser Curves: 0.10–2.00, 0.01 steps

Curve Timing Accuracy: ±1.50 cycles plus ±4% of setting, between 2 and 30 multiples of pickup

Second-Harmonic Blocking Elements

Pickup Range: 5%–100% of fundamental, 1% steps

Steady-State Pickup Accuracy: 2.5 percentage points

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Pickup/Dropout Time:	<1.25 cycles
Time Delay:	0.00–16,000.00 cycles, 0.25-cycle steps
Timer Accuracy:	±0.25 cycle and ±0.1% of setting

Undervoltage (27) and Overvoltage (59)

Pickup Ranges (V Secondary)

300 V Maximum Inputs

Phase:	1.00–300.00 V, 0.01 V steps
Phase-to-Phase:	1.76–520.00 V, 0.02 V steps
Sequence:	2.00–300.00 V, 0.02 V steps

8 V LEA Maximum Inputs

Phase:	0.03–8.00 V[a]
Phase-to-Phase:	0.05–13.87 V[a]
Sequence:	0.05–8.00 V[a]

Eaton NOVA LEA Inputs (37 Vac Maximum)

Phase:	0.12–37.09 V[a]
Phase-to-Phase:	0.21–64.24 V[a]
Sequence:	0.25–37.09 V[a]

Lindsey SVMI LEA Inputs (200 Vac Maximum)

Phase:	1.00–200.00 V
Phase-to-Phase:	1.76–346.00 V
Sequence:	2.00–200.00 V

Siemens LEA Inputs (8.49 Vac Maximum)

Phase:	0.03–8.49 V[a]
Phase-to-Phase:	0.05–14.72 V[a]
Sequence:	0.05–8.00 V[a]

Steady-State Pickup Accuracy

300 V Maximum

Phase:	±0.5 V plus ±1% of setting
Phase-to-Phase:	±1 V plus ±2% of setting
Sequence:	±1.5 Vac plus ±3% of setting @ 12.5–300.0 Vac

8 V LEA Maximum[a]

Phase:	±10 mV plus ±1% of setting
Phase-to-Phase:	±20 mV plus ±2% of setting
Sequence:	±30 mVac plus ±3% of setting @ 0.33–8.00 Vac

Eaton NOVA LEA[a]

Phase:	±60 mV plus ±1% of setting
Phase-to-Phase:	±120 mV plus ±2% of setting
Sequence:	±180 mVac plus ±3% of setting @ 1.55–37.09 Vac

Lindsey SVMI LEA[a]

Phase:	±0.5 V plus ±1% of setting
Phase-to-Phase:	±1 V plus ±2% of setting
Sequence:	±1.5 Vac plus ±3% of setting @ 12.5–200.0 Vac

Siemens LEA[a]

Phase:	±10 mV plus ±1% of setting
Phase-to-Phase:	±20 mV plus ±2% of setting
Sequence:	±30 mVac plus ±3% of setting @ 0.33–8.49 Vac

Transient Overreach:	±5%
Pickup/Dropout Time:	<1.25 cycles

Synchronism-Check Elements (25)

Slip Frequency Pickup Range:	0.005–0.500 Hz, 0.001 Hz steps
Slip Frequency Pickup Accuracy:	±0.003 Hz
Phase Angle Range:	0–80°, 0.01° steps
Phase Angle Accuracy:	±4°

Under- and Overfrequency Elements (81)

Frequency Range:	40.00–65.00 Hz, 0.01 Hz steps
Frequency Accuracy:	±0.01 Hz
Time Delay Range:	2.00–16,000.00 cycles, 0.25-cycle steps
Time Delay Accuracy:	±0.25 cycle plus ±0.1%

Undervoltage Frequency Element Block Range

300 V Inputs:	12.50–300.00 V[a]

Rate-of-Change-of-Frequency Element

Pickup Range:	0.10–15.00 Hz/s, 0.01 Hz/s steps
Dropout:	95% of pickup
Pickup Accuracy:	±100 mHz/s and ±3.33% of pickup
Pickup/Dropout Time:	See *Equation 4.5*.
Pickup Time Delay:	0.10–60.00 seconds, 0.01-second steps
Dropout Time Delay:	0.00–60.00 seconds, 0.01-second steps
Timer Accuracy:	±6 ms and ±0.1% of setting

Power Elements[b]

Minimum Current:	0.01 A
Minimum Voltage:	40 V
Steady-State Pickup Accuracy:	0.58 W plus ±5% of setting at unity power factor
Pickup/Dropout Time:	<3.75 cycles
Time Delay Accuracy:	±0.25 cycle plus ±0.1% of setting

Load Encroachment[b]

Minimum Current:	0.1 A
Minimum Voltage:	12.5 Vac
Forward Load Impedance:	0.5–640.0 ohms secondary
Forward Positive Load Angle:	−90° to +90°
Forward Negative Load Angle:	−90° to +90°
Negative Load Impedance:	0.50–640 ohms secondary
Negative Positive Load Angle:	+90° to +270°
Negative Negative Load Angle:	+90° to +270°

Pickup Accuracy

Impedance:	±3%
Angle:	±2°

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SELogic Control Equation Variable Timers

Pickup Ranges

0.00–999,999.00 cycles: 0.25-cycle steps (programmable timers)

Pickup/Dropout Accuracy: ±0.25 cycle plus ±0.1% of setting

Metering Accuracies

Accuracies specified at 20°C and at nominal system frequency unless noted otherwise.

Instantaneous and Maximum/Minimum Metering

Voltages

VAY, VBY, VCY, VAZ, VBZ, VCZ:	±0.2% (50–300 V), ±0.5° for PTs
	±0.2% (0.67–8.00 V), ±0.5° for 8 V LEAs
	±0.2% (3.09–37.09 V), ±0.5° for Eaton NOVA LEAs
	±0.2% (25–200.00 V), ±0.5° for Lindsey SVMI LEAs
	±0.2% (0.71–8.49 V), ±0.5° for Siemens SDR LEAs
VABY, VBCY, VCAY, VABZ, VBCZ, VCAZ:	±0.4% (50–300 V), ±1.0° for PTs
	±0.4% (1.16–13.86 V), ±1.0° for 8 V LEAs
	±0.4% (5.35–64.28 V), ±1.0° for Eaton NOVA LEAs
	±0.4% (43.30–346.41 V), ±1.0° for Lindsey SVMI LEAs
	±0.4% (1.22–14.70 V), ±1.0° for Siemens SDR LEAs
3V0Y, V1Y, V2Y, 3V0Z, V1Z, V2Z:	±0.6% (50–300 V), ±1.0° for PTs
	±0.6% (0.67–8.00 V), ±1.0° for 8 V LEAs
	±0.6% (3.09–37.09 V), ±1.0° for Eaton NOVA LEAs
	±0.6% (25.00–200.00 V), ±1.0° for Lindsey SVMI LEAs
	±0.6% (0.71–8.49 V), ±1.0° for Siemens SDR LEAs

Currents

IA, IB, IC[c]:	±0.5 mA plus ±0.1% of reading (0.1–2.0 A), ±0.5°
IN:	±0.08 mA plus ±0.1% of reading (0.005–4.5 A), ±1°
3I1, 3I0, 3I2:	±0.01 A plus ±3% of reading (0.1–2.0 A), ±1°

Power

Apparent (MVA)

MVAA, MVAB, MVAC, MVA3P:	±1.2% (V_{phase} > 50 Vac[d], I_{phase} > 0.1 A)

Real (MW)

MWA, MWB, MWC, MW3P:	±0.7% @ PF = 1, ±1.0% @ PF > 0.87 (V_{phase} > 50 Vac[d], I_{phase} > 0.1 A)

Reactive (MVAR)

MVARA, MVARB, MVARC, MVAR3P:	±0.7% @ PF = 0, ±1.0% @ PF < 0.50 (V_{phase} > 50 Vac[d], I_{phase} > 0.1 A)

Energy

Megawatt Hours (In and Out)

MWhA, MWhB, MWhC, MWh3P:	+1.2% @ PF = 1, (V_{phase} > 50 Vac[d], I_{phase} > 0.1 A)

Megavar Hours (In and Out)

MVARhA, MVARhB, MVARhC, MVARh3P:	+1.2% @ PF = 0, (V_{phase} > 50 Vac[d], I_{phase} > 0.1 A)

Demand Metering

Currents

IA, IB, IC:	±0.25% (0.1–2.0 A)
IN (Measured):	±0.25% (0.005–4.5 A)
3I2, 3I0 (IG):	±3% ± 0.01 A, (0.1–20.0 A)

Synchrophasor Accuracy

Maximum Data Rate in Messages per Second

IEEE C37.118 Protocol:	60 (nominal 60 Hz system) 50 (nominal 50 Hz system)
SEL Fast Message Protocol:	1
IEEE C37.118-2005 Accuracy:	Level 1 at maximum message rate when phasor has the same frequency as A-phase voltage, frequency-based phasor compensation is enabled (PHCOMP := Y), and the narrow band filter is selected (PMAPP := N). Out-of-band interfering frequency (Fs) test, 10 Hz ≤ Fs ≤ (2 • NFREQ).
Current Range:	(0.2–2.0) • I_{nom} (I_{nom} = 1 A phase, 0.2 A neutral)
Frequency Range:	±5 Hz of nominal (50 or 60 Hz)
Voltage Range:	30–250 V for PTs 0.8–8.0 V for 8 V LEA inputs 3.71–37.09 V for Eaton NOVA LEA inputs 30–300 V for Lindsey SVMI LEA inputs 0.85–8.49 V for Siemens SDR LEA inputs
Phase Angle Range:	–179.99° to +180.00°

Harmonic Metering

Voltages VAY, VBY, VCY, VAZ, VBZ, VCZ

Accuracies valid for THD <100%, 30 V < fundamental < 200 V sec, 50 Hz or 60 Hz

Fundamental Magnitude:	±5%
02–16 Harmonic Percentage:	±5 percentage points[e]

Currents I_A, I_B, I_C, I_N

Accuracies valid for THD <100%, fundamental voltage <200 V, 50 Hz or 60 Hz

1 A and 0.2 A Nominal: 0.02 A < fundamental current < 1 A sec

Fundamental Magnitude:	±5%
02–16 Harmonic Percentage:	±5 percentage points[e]

RMS Metering

Voltages

VAY, VBY, VCY, VAZ, VBZ, VCZ:	±1.2% V_{phase} > 50 Vac[d] for PTs

Currents

I_A, I_B, I_C:	±0.5 mA plus ±0.2% (0.1–2.0 A)
I_N (Measured):	±0.08 mA plus ±0.20% (0.005–4.500 A)

Average Real Power (MW)

MWA, MWB, MWC, MW3P:	±2.0% @ PF = 1 (V_{phase} > 50 Vac[c], I_{phase} > 0.1 A)

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Type Tests

Recloser Type Tests

IEEE C37.60-2003, Section 6.13 Control Electronic Elements Surge Withstand Capability (SWC) Tests

6.13.1 Oscillatory and fast transient surge tests (a control-only test, performed in accordance with IEEE C37.90.1-2002)

6.13.2 Simulated surge arrester operation test (performed with the control connected to the following reclosers)

G&W Viper-ST:	27 kV, 12.5 kA interrupting, 800 A continuous
	38 kV, 12.5 kA interrupting, 800 A continuous
ABB Elastimold MVR:	15/17 kV, 12.5 kA interrupting, 800 A continuous
	38 kV, 12.5 kA interrupting, 800 A continuous
Eaton NOVA:	27 kV, 12.5 kA interrupting, 630 A continuous
Eaton Recloser Type "WVE-27":	38 kV, 8 kA interrupting, 560 A continuous
ABB OVR-3:	27 kV, 12.5 kA interrupting, 630 A continuous
Eaton NOVA-TS:	15.5 kV, 8 kA interrupting, 400 A continuous
Eaton NOVA (Control Powered):	27 kV, 12.5 kA interrupting, 630 A continuous
Tavrida OSM Al_2:	27 kV, 12.5 kA interrupting, 600 A continuous
Tavrida OSM Al_4:	27 kV, 12.5 kA interrupting, 600 A continuous

IEC 62271-111:2012/IEEE C37.60-2012, Section 6.111 Control Electronic Elements Surge Withstand Capability (SWC) Tests

6.111.2 Oscillatory and fast transient surge tests

6.111.3 Simulated surge arrester operation test

Both performed with the control connected to the following reclosers:

G&W Electric Viper-ST, Solid Dielectric:

Voltage Rating:	38 kV
Current Break Rating:	12.5 kA
Continuous Current Rating:	800 A

Eaton Type NOVA 15, Aux. Power

Voltage Rating:	15.5 kV
Current Break Rating:	12.5 kA
Continuous Current Rating:	630 A

Tavrida OSM25_Al_2(630_150_2)

Voltage Rating:	27 kV
Current Break Rating:	12.5 kA
Continuous Current Rating:	630 A

ABB OVR/Gridshield TS Recloser (32-Pin)

Voltage Rating:	27 kV
Current Break Rating:	12.5 kA
Continuous Current Rating:	1000 A

Electromagnetic Compatibility Emissions[f]

Radiated and Conducted Emissions:
EN/IEC 60255-26:2013, Section 7.1
CISPR 22:2008
EN 55022:2010 + AC:2011
CISPR 11:2009 + A1:2010
EN 55011:2009 + A1:2010
FCC 47 CFR:2014, Part 15.107
FCC 47 CFR:2014, Part 15.109
Severity Level: Class A

Electromagnetic Compatibility Immunity[f]

Radiated RF Immunity:
EN/IEC 60255-26:2013, Section 7.2.4
IEC 61000-4-3:2006 + A1:2007 + A2:2010
EN 61000-4-3:2006 + A1:2008 + A2:2010
Severity Level: 10 V/m
IEEE C37.90.2-2004
Severity Level:
20 V/m (average)
35 V/m (peak)

Conducted RF Immunity:
EN/IEC 60255-26:2013, Section 7.2.8
IEC 61000-4-6:2008
EN 61000-4-6:2009
Severity Level: 10 Vrms

Electrostatic Discharge Immunity:
EN/IEC 60255-26:2013, Section 7.2.3
IEC 61000-4-2:2008
Levels 2, 4, 6, and 8 kV contact;
Levels 2, 4, 8, and 15 kV air
IEEE C37.90.3-2001
Levels 2, 4, and 8 kV contact;
Levels 4, 8, and 15 kV air

Electrical Fast Transient Burst Immunity:
EN/IEC 60255-26:2013, Section 7.2.5
EN/IEC 61000-4-4:2012
4 kV, 5 kHz on power supply, I/O, and ground
2 kV, 5 kHz on communications ports

Surge Immunity[g, h]:
EN/IEC 60255-26:2013, Section 7.2.7
Severity Level: Zone A
Severity Level: Zone B on IRIG-B
IEC 61000-4-5:2005
EN 61000-4-5:2006
Severity Level 4:
2 kV line-to-line
4 kV line-to-earth
Severity Level 3 on IRIG-B:
2 kV line-to-earth

Surge Withstand Capability:
EN/IEC 60255-26:2013, Section 7.2.6
IEC 61000-4-18:2006 + A1:2010
EN 61000-4-18:2007 + A1:2010
Severity Level:
Power supply and I/O
2.5 kV common mode
1.0 kV differential mode
Communications ports
1.0 kV common mode
IEEE C37.90.1-2012
2.5 kV oscillatory
4.0 kV fast transient

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Environmental

Cold[f]: IEC 60068-2-1:2007
Test Ad: 16 hours at –40°C

Damp Heat, Cyclic[f]: IEC 60068-2-30:2005
Test Db: 25° to 55°C, 6 cycles,
Relative Humidity: 95%

Dry Heat[f]: IEC 60068-2-2:2007
Test Bd: Dry heat, 16 hours at +85°C

Vibration[f]: IEC 60255-21-1:1988
EN 60255-21-1:1995
Severity Level:
Endurance Class 1
Response Class 2
IEC 60255-21-2:1988
EN 60255-21-2:1995
Severity Level:
Shock Withstand, Bump Class 1
Shock Response Class 2
IEC 60255-21-3:1993
EN 60255-21-3:1995
Severity Level:
Quake Response Class 2

Enclosure Ingress
Protection[i]: IEC 60529:2001 + CRGD:2003
[BS EN 60529 Second Edition—1992
+ REAF:2004]
IP45

Safety[f]

Insulation Coordination

IEC 60255-27:2013; Section 10.6.4
EN 60255-27:2014; Section 10.6.4
IEEE C37.90-2005, Section 8
Severity Level—HiPot:
2.5 kVac on optoisolated inputs, contact outputs, CTs, and PTs
0.75 kVdc on IRIG-B, EIA-485, and Ethernet ports
3.6 kVdc on power supply
Type tested for one minute
Severity Level—Impulse:
5.0 kV on optoisolated inputs, contact outputs, CTs, PTs, and
power supply
0.8 kV on IRIG-B, EIA-485, and Ethernet ports

[a] See Section 9: Settings for details on how to set voltage elements when using LEA inputs.
[b] Voltage, Power, and Impedance values listed for 300 Vbase (PT) inputs.
[c] Accuracies specified with balanced phase voltages at 120 Vac.
[d] Voltage threshold for given accuracy is 0.67 Vac for 8 V LEA inputs, 1.70 Vac for Eaton NOVA LEA inputs, 14.00 Vac for Lindsey SVMI LEA inputs, and 0.60 Vac for Siemens SDR LEA inputs.
[e] For example, for a particular harmonic value applied at 10% of fundamental, the harmonic value meters in the range of 5% to 15%.
[f] SEL enclosure excluded from test.
[g] Serial cable (non-fiber) lengths assumed to be <3 m.
[h] The following pickup/dropout delays are used:
Under- and overvoltage elements: 0.0/0.0 cycles
(Eaton NOVA and Lindsey LEAs required 6.0/6.0 cycles)
Phase instantaneous overcurrent elements: 0.5/1.0 cycles
Neutral instantaneous overcurrent elements: 0.0/4.0 cycles
Digital inputs: 0.5/0.5 cycles
[i] SEL enclosure included in test.

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Section 2

Installation

Overview

In addition to a general hardware overview and standard installation information, this section contains the following detail information for the various reclosers that are compatible with the SEL-651R-2 Recloser Control:

➤ Drill and cutout dimensions for connector panel at bottom of enclosure (see *Figure 2.10–Figure 2.26*)

➤ Voltage connections, including low-energy analog (LEA) voltage inputs available with some reclosers (see *Figure 2.41–Figure 2.46*)

➤ Control cable receptacle pinouts (see *Figure 2.34*)

➤ Current, trip/close and recloser status connections that pass through the control cable (see *Figure 2.49–Figure 2.80*)

Dual-Door Enclosure Hardware Overview

The control consists of four major pieces:

➤ Enclosure

➤ Power Module

➤ Relay Module

➤ Battery

These pieces are shown in *Figure 2.1* and are described briefly in the following text.

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Dual-Door Enclosure Hardware Overview

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Figure 2.1   SEL-651R-2 Front View With Enclosure Front Door Open (Dual-Door Enclosure)

Enclosure

NOTE: Serial number stickers are provided for the enclosure, power module, and relay module.

NOTE: A lock with a 9.53 mm (3/8-inch) diameter shackle will work with any padlockable handle. The cold rolled steel enclosure with a single-point latch will accept a shackle with a diameter as large as 12.7 mm (0.5 inches).

Select the painted cold-rolled steel enclosure (NEMA 3R rated) for normal applications or the painted type 304 stainless steel enclosure (NEMA 3RX rated) to reduce corrosion in harsh environments. Each enclosure provides a 19-inch rack and ample space for mounting of the relay module, power supply module, and accessories (e.g., radio). It includes a front door for fast and easy access to the front-panel HMI and a rear door for easy access to wiring and fuses. SEL fiber-optic transceivers can mount on serial ports, with enough room for training the fiber-optic cable.

The front-door document holder is 22.9 cm (9 in) wide, by 3.0 cm (1.2 in) deep. It can carry items weighing as much as 0.902 kg (2 lb).

Near the upper corner of the enclosure (side near the pole), a small louvered vent is installed for the venting of battery gases.

Painted cold-rolled steel enclosures without a three-point latch have a padlockable handle on the front door, and a quarter-turn padlockable latch on the rear door. Painted stainless steel enclosures and cabinets with the three-point latches have padlockable handles on the front and rear doors.

The internal 19-inch rack system is designed according to the IEC 297 19-inch rack standard and accepts #10-32 screws.

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Power Module

Figure 2.2 provides an overview of the major interconnections among the components within the SEL-651R-2 enclosure.
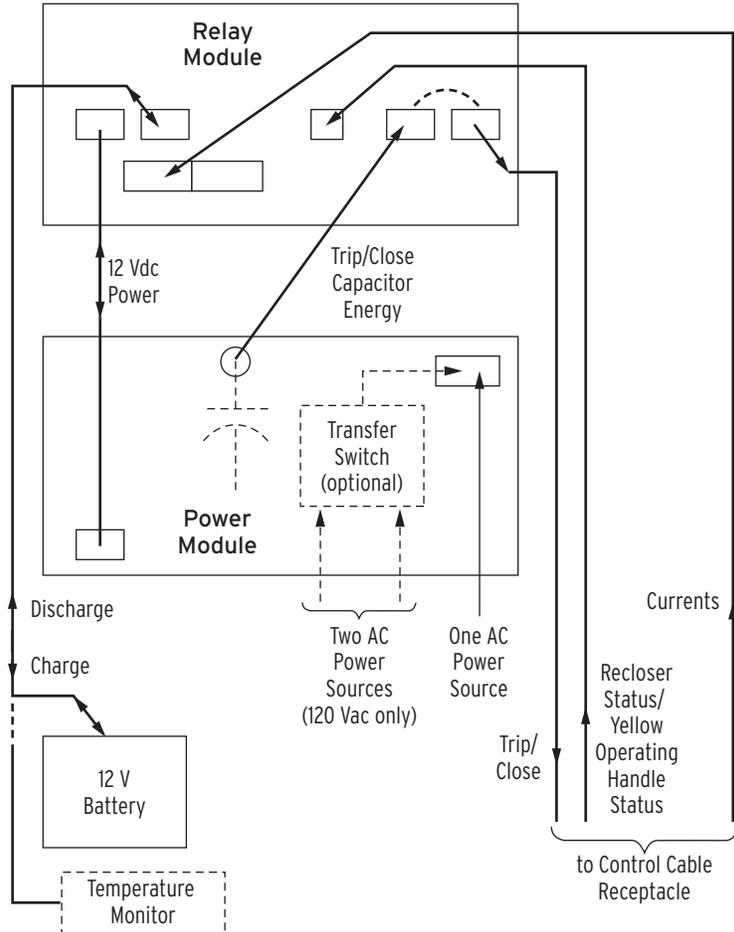
Figure 2.2   Major Interconnections Between SEL-651R-2 Components—Rear View (Dual-Door Enclosure)

The power module is ordered with one input power option:

➤ 120 Vac (includes a GFCI [Ground Fault Circuit Interrupter] convenience outlet on front)

➤ 230 Vac (two-wire)

➤ 125 Vdc

➤ or 48 Vdc

If two sources of 120 Vac power are brought to the power module, they must first be routed through a transfer switch on the power module. The output of the transfer switch is then connected to the power module inputs, as shown in *Figure 2.2*.

12 Vdc is output from the power module to power the relay module. The trip/close capacitor is charged inside the power module and this energy source is connected (via wire harness) to the trip and close output circuits in the relay module.

2.4 Installation
Dual-Door Enclosure Hardware Overview

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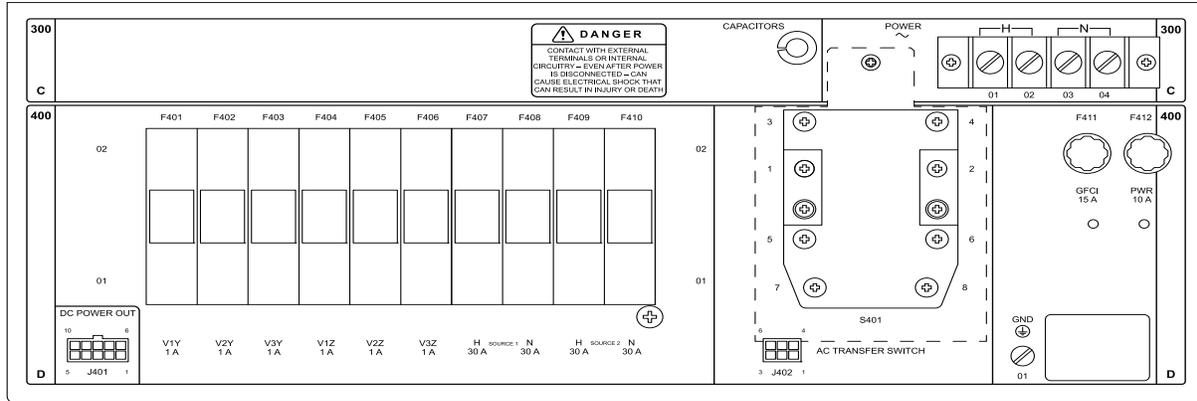
Figure 2.3 Rear View of SEL-651R-2 Power Module (Dual-Door Enclosure, Optional Features Shown)

Relay Module

Each SEL-651R-2 relay module provides protection, control, and monitoring features. The relay module is powered from 12 Vdc from the power module, as shown in *Figure 2.2*. This 12 Vdc also powers the battery charger in the relay module and is available as auxiliary power, such as for powering a radio. Secondary currents and voltages from the power system and recloser status are input to the relay module.

Trip and close signals are output from the relay module, with the trip/close capacitor (connected from the power module) providing the energy to actuate the trip or close operation.

Slide-in configurable front-panel labels can be customized for unique applications.
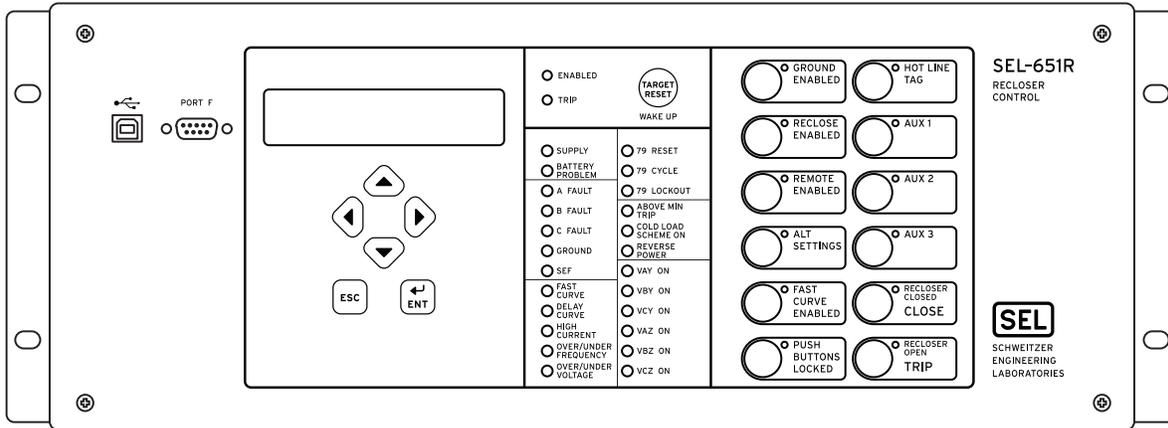
Figure 2.4 Front View of SEL-651R-2 Relay Module (Dual-Door Enclosure)

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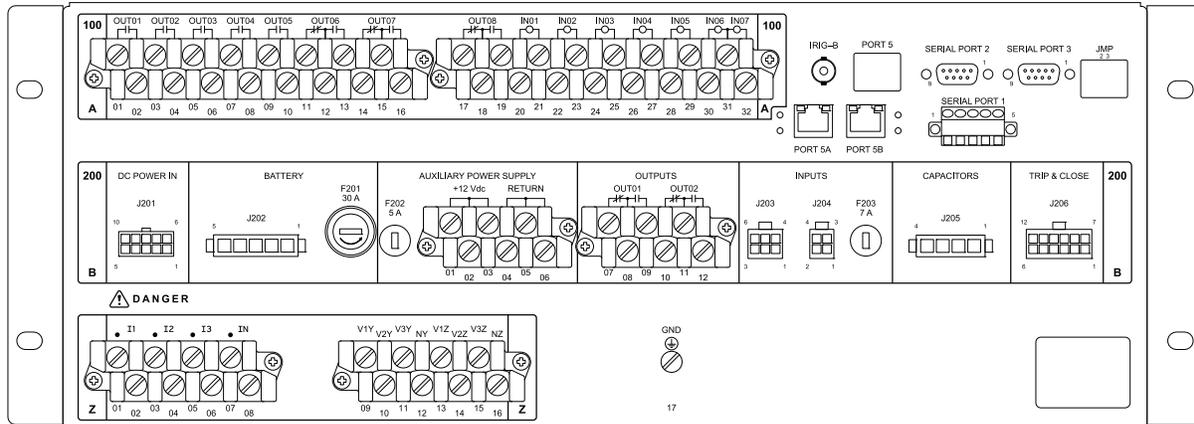
Figure 2.5   Rear View of SEL-651R-2 Relay Module (Dual-Door Enclosure, Optional Features Shown)

The internal wiring details of SEL-651R-2 relay module connectors J202, J203, J204, and J206 are shown in the following figures.

➤ J202 (BATTERY) is shown in *Figure 2.29*

➤ J203 (INPUTS) is shown in *Figure 2.50*, *Figure 2.54*, *Figure 2.57*, *Figure 2.60*, *Figure 2.64*, *Figure 2.66*, *Figure 2.67*, *Figure 2.69*, *Figure 2.72*, *Figure 2.73*, and *Figure 2.80*

➤ J204 (INPUTS) is shown in *Figure 2.60*, *Figure 2.67*, and *Figure 2.51*

➤ J206 (TRIP & CLOSE) is shown in *Figure 2.50*, *Figure 2.53*, *Figure 2.56*, *Figure 2.60*, *Figure 2.63*, *Figure 2.66*, *Figure 2.69*, *Figure 2.72*, *Figure 2.73*, and *Figure 2.79*

The internal wiring details for connectors J201 (DC POWER IN) and J205 (CAPACITORS) are not shown. J201 and J205 should only be connected to the factory-supplied harnesses emanating from the SEL-651R-2 power module. See *Figure 2.2* for an overview of such major interconnections.

Battery

Either a 16 or 40 Ah extended temperature 12 V battery is shipped with the recloser control. The battery sits upon a slightly raised platform. This platform provides space underneath for the battery temperature monitor, as shown in *Figure 2.2*.

See *Battery Installation and Connection on page 2.30* and *Battery and Fuse Replacement on page 2.57* for more information on battery service and characteristics.

Single-Door Enclosure Hardware Overview

The control consists of four major pieces:

➤ Enclosure

➤ Power Module

➤ Relay Module

➤ Battery

2.6 Installation
Single-Door Enclosure Hardware Overview

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These pieces are shown in *Figure 2.6* and are described briefly in the following text.

Figure 2.6   SEL-651R-2 Front View With Enclosure Door Open (Single-Door Enclosure)

Enclosure

NOTE: Serial number stickers are provided for the enclosure, power module, and relay module.

NOTE: A lock with a 9.53 mm (3/8-inch) diameter shackle will work with any padlockable handle. The cold rolled steel enclosure with a single-point latch will accept a shackle with a diameter as large as 12.7 mm (0.5 inches).

Select the painted cold-rolled steel enclosure (NEMA 3R rated) for normal applications or the painted type 304 stainless steel enclosure (NEMA 3RX rated) to reduce corrosion in harsh environments. Each single-door enclosure provides space for mounting of the relay module, power supply module, and accessories (e.g., radio). It includes a door for fast and easy access to the front-panel HMI and a swing-panel for easy access to wiring and fuses.

The front-door document holder is 22.9 cm (9 in) wide, by 3.0 cm (1.2 in) deep. It can carry items weighing as much as 0.902 kg (2 lb).

At the rear of the enclosure (near the mounting bracket), a small louvered vent is installed for the venting of battery gases.

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Installation 2.7
Single-Door Enclosure Hardware Overview

Power Module

Figure 2.7 provides an overview of the major interconnections between the components within the SEL-651R-2 enclosure.
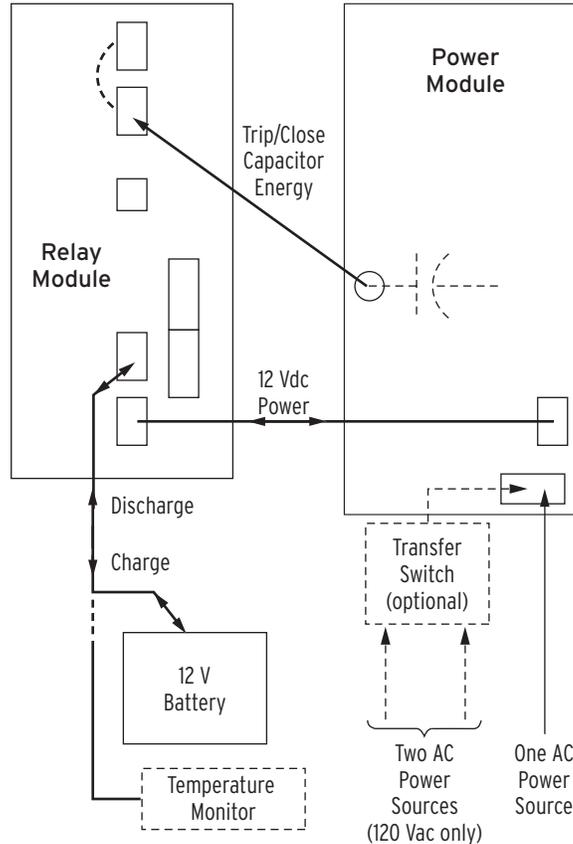
Figure 2.7 Major Interconnections Between SEL-651R-2 Components−Front View (Single-Door Enclosure)

The power module is ordered with one input power option:

➤ 120 Vac (includes a GFCI [Ground Fault Circuit Interrupter] convenience outlet in the cabinet)

➤ 230 Vac (two-wire)

➤ 125 Vdc

➤ or 48 Vdc

If two sources of 120 Vac power are brought to the power module, they must first be routed through a transfer switch. The output of the transfer switch is then connected to the power module inputs, as shown in *Figure 2.7*.

The power module outputs 12 Vdc to power the relay module. The trip/close capacitor is charged inside the power module and this energy source is connected (via wire harness) to the trip and close output circuits in the relay module.

2.8 Installation
Single-Door Enclosure Hardware Overview

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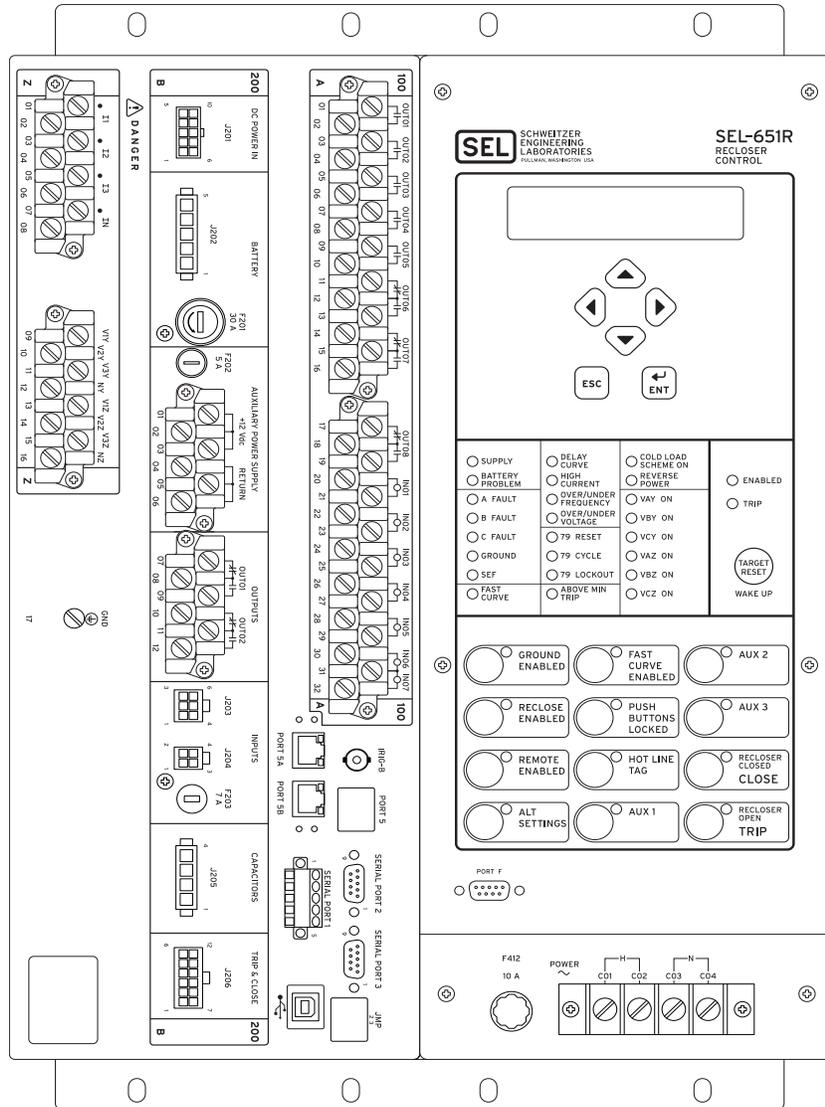
Figure 2.8   Front View of SEL-651R-2 Modules (Single-Door Enclosure, Optional Features Shown)

Relay Module

Each SEL-651R-2 relay module provides protection, control, and monitoring features. The relay module is powered from 12 Vdc from the power module, as shown in *Figure 2.7*. This 12 Vdc also powers the battery charger in the relay module and is available as auxiliary power, such as for powering a radio. Secondary currents and voltages from the power system and recloser status are input to the relay module.

Trip and close signals are output from the relay module, with the trip/close capacitor (connected from the power module) providing the energy to actuate the trip or close operation.

Slide-in configurable front-panel labels can be customized for unique applications.
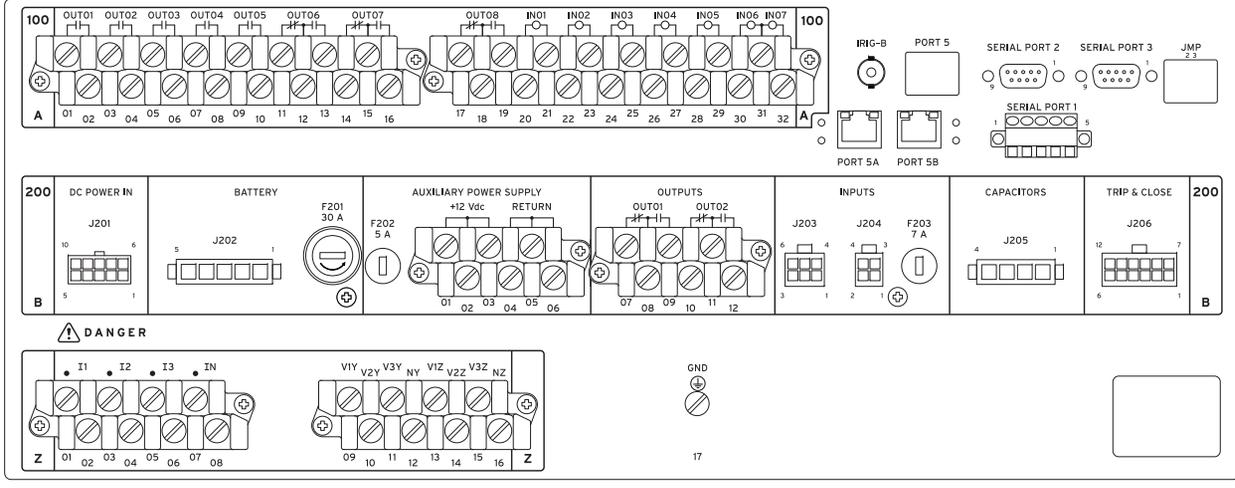
Figure 2.9 View of SEL-651R-2 Relay Module (Single-Door Enclosure, Optional Features Shown)

The internal wiring details of SEL-651R-2 relay module connectors J202, J203, J204, and J206 are shown in the following figures.

▲ J202 (BATTERY) is shown in *Figure 2.29*.

▲ J203 (INPUTS) is shown in *Figure 2.50*, *Figure 2.54*, *Figure 2.57*, *Figure 2.60*, *Figure 2.64*, *Figure 2.66*, *Figure 2.67*, *Figure 2.69*, *Figure 2.72*, *Figure 2.73*, and *Figure 2.80*.

▲ J204 (INPUTS) is shown in *Figure 2.60*, *Figure 2.67*, and *Figure 2.51*.

▲ J206 (TRIP & CLOSE) is shown in *Figure 2.50*, *Figure 2.53*, *Figure 2.56*, *Figure 2.60*, *Figure 2.63*, *Figure 2.66*, *Figure 2.69*, *Figure 2.72*, *Figure 2.73*, and *Figure 2.79*.

2.10 | Installation
No Enclosure Options

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The internal wiring details for connectors J201 (DC POWER IN) and J205 (CAPACITORS) are not shown. J201 and J205 should only be connected to the factory-supplied harnesses emanating from the SEL-651R-2 power module (see *Figure 2.7* for an overview of such major interconnections).

Battery

Either a 16 or 40 Ah extended temperature 12 V battery is shipped with the recloser control. The battery sits upon a slightly raised platform. This platform provides space underneath for the battery temperature monitor, as shown in *Figure 2.7*.

See *Battery Installation and Connection on page 2.30* and *Battery and Fuse Replacement on page 2.57* for more information on battery service and characteristics.

No Enclosure Options

**CHOOSE HORIZONTAL
OR VERTICAL**
Choose between horizontal (Figure 2.3, Figure 2.4, and Figure 2.5) or vertical (Figure 2.8 and Figure 2.9) relay and power modules for the **no enclosure** option.

⚠**CAUTION**
The battery temperature sensor board contains exposed components that are sensitive to Electrostatic Discharge (ESD). When working with this board, work surfaces and personnel must be properly grounded or equipment damage may result.

SEL-651R-2 recloser controls can be ordered from SEL without enclosures. This option might be used where the control will be installed in a substation environment or where a custom enclosure will be used. An SEL-651R-2 ordered with no enclosure consists of four items:

➤ Relay Module

➤ Power Module

➤ Battery Temperature Sensor (with cables) (ac powered models only)

➤ Wiring Harnesses

All hardware is as described in the previous sections. See *Installation Steps and Drawings on page 2.10* and *Recloser Interface Connection Details (Control Cable Interface) on page 2.59* for details on wiring the recloser control.

Installation Steps and Drawings

Dual-Door Control Mounting

⚠**WARNING**
Have only qualified personnel service this equipment. If you are not qualified to service this equipment, you can injure yourself or others, or cause equipment damage.

The drill plan detailed in *Figure 2.10* (37 inches on center) is the same as the traditional drill plan for double-size Eaton enclosures. If a retrofit of such an enclosure is taking place, no extra drilling of the pole or mounting structure is needed.

Mounting Bolts/Washers: SEL does not provide the 5/8-inch mounting bolt/washer assemblies required for mounting the SEL-651R-2. The mounting hole on the enclosure is 2 inches in diameter, so any washer used with the mounting bolt must be less than 2 inches in diameter.

The SEL-651R-2 has one 1.5-inch diameter lifting hole on the mounting-bracket (angled out on top at 45 degrees) and one 1.5-inch diameter lifting hole on the smaller centered bracket at the top of the other side of the enclosure.

Step 1. Secure lifting attachments to the lifting holes.

Step 2. Lift slowly.

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Installation Steps and Drawings
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⚠DANGER

If the recloser is energized while the control cable is disconnected from the recloser control, the CT secondaries in the control cable may generate dangerously high voltages. Do not come in contact with the pins or pin sockets in the control cable. Contact with high voltage can cause serious injury or death.

Step 3. Slip the top mounting hole/keyway over the top mounting bolt/washer assembly.

Step 4. Rest the unit on the bolt, settled in the keyway slot.

Step 5. Secure the bottom mounting bracket with another mounting bolt/washer assembly.

Step 6. Secure both top and bottom mounting bolt/washer assemblies.

The unit weighs (fully featured) 68 kg (≤150 lb), without the battery. Battery weights are given in *Table 2.2*.

Dual-Door Drawings

POLE-MOUNT ENCLOSURE

Ø1.50 (Ø38.1)
LIFTING HOLES

41.50
(1054.2)

MOUNT

37.00
(939.8)

FRONT

30.00
(762.0)

SIDE

24.50
(622.3)

19.55
(495.3)

MOUNTING HOLES FOR Ø5/8 (Ø16.0) BOLTS (TYP)

LEGEND
in
(mm)

16.60
(421.7)

CONNECTOR PANEL

BASE
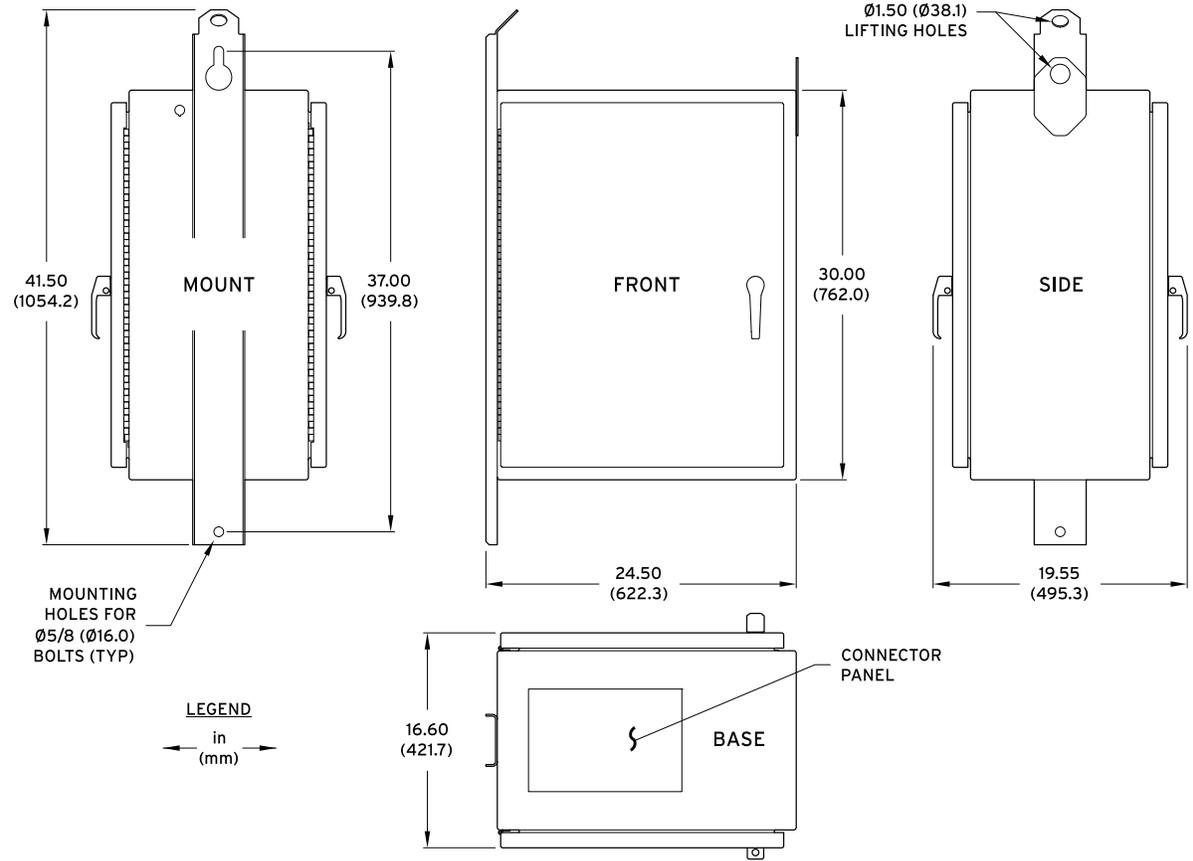
Figure 2.10   SEL-651R-2 Enclosure Dimensions and Mounting Drill Plan (Dual-Door Enclosure)

2.12 Installation
Installation Steps and Drawings

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TOP VIEW FROM INSIDE ENCLOSURE

GROUNDING LUG

NOTE 1

SEE DETAIL A

12.90 (327.7)
11.90 (302.3)
7.00 (177.8)
Ø0.88 (Ø22.4) 2 PLACES
8.00 (203.2)
9.00 (228.6)
4.50 (114.3)
2.25 (57.2)
8.50 (215.9)
2.25 (57.2)
1.50 (38.1)
2.70 (68.6)
3.53 (89.7)
3.65 (92.7)
Ø0.22 (Ø5.6) 6 PLACES
12.40 (315.0)

DETAIL A

2.75 (69.9)
Ø0.25 (Ø6.4) 10 PLACES
1.25 (31.8)
Ø1.50 (Ø38.1) 5 PLACES
Ø0.13 (Ø3.3) 20 PLACES
1.25 (31.8)

LEGEND
in
(mm)

NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.11   Connector Panel at Bottom of Enclosure for Traditional Retrofit, Control-Powered Eaton NOVA, and G&W Control Power Viper-S Reclosers (Dual-Door Enclosure)

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Installation 2.13
Installation Steps and Drawings
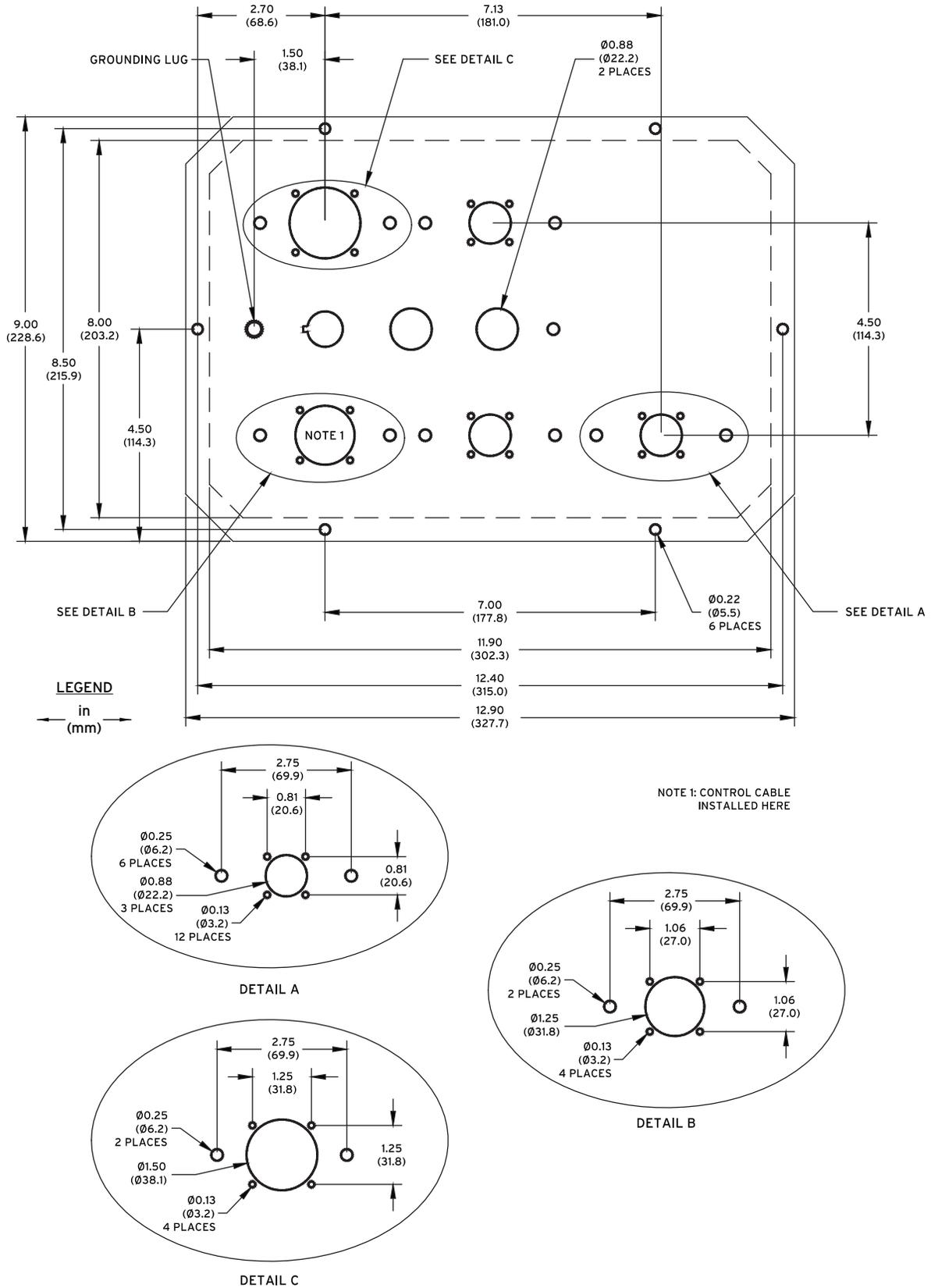
Figure 2.12   Connector Panel at Bottom of Enclosure for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, and ABB OVR/Gridshield (32-Pin) Reclosers (Dual-Door Enclosure)

2.14 | Installation
| **Installation Steps and Drawings**

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TOP VIEW FROM
INSIDE ENCLOSURE

SEE DETAIL A

12.90
(327.7)

11.90
(302.3)

7.00
(177.8)

SEE DETAIL B

8.00
(203.2)

9.00
(228.6)

1.75
(44.5)

NOTE 1

4.50
(114.3)

2.25
(57.2)

Ø0.88
(Ø22.4)
3 PLACES

GROUNDING LUG

1.75
(44.5)

Ø0.22
(Ø5.6)
6 PLACES

2.95
(74.9)

3.25
(82.6)

6.83
(173.5)

12.40
(315.0)

1.38
(35.0)

Ø0.18
(Ø4.5)
4 PLACES

Ø0.25
(Ø6.2)
2 PLACES

4.45
(113.0)

5.12
(130.0)

2.56
(65.0)

1.26
(32.0)

2.09
(53.2)

0.85
(21.5)

2.75
(69.9)

Ø0.25
(Ø6.4)
4 PLACES

Ø1.50
(Ø38.1)
2 PLACES

1.25
(31.8)

Ø0.13
(Ø3.3)
8 PLACES

1.25
(31.8)

DETAIL B

LEGEND

in
(mm)

NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.13   Connector Panel at Bottom of Enclosure for ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Recloser (Dual-Door Enclosure)

2.15
Installation
Installation Steps and Drawings

TOP VIEW FROM
INSIDE ENCLOSURE

SEE DETAIL A

SEE DETAIL B

12.90
(327.7)

11.90
(302.3)

7.00
(177.8)

8.00
(203.2)

9.00
(228.6)

4.50
(114.3)

NOTE 1

2.25
(57.2)

8.50
(215.9)

Ø0.22
(Ø5.6)
6 PLACES

GROUNDING LUG

2.50
(63.5)

2.58
(65.4)

Ø0.88
(Ø22.2)
2 PLACES

3.70
(94.0)

6.10
(154.9)

12.40
(315.0)

Ø0.17
(Ø4.4)
4 PLACES

1.94
(49.2)

1.94
(49.2)

Ø2.31
(Ø58.7)

DETAIL A

2.75
(69.9)

Ø0.25
(Ø6.4)
4 PLACES

1.25
(31.8)

Ø1.50
(Ø38.1)
2 PLACES

Ø0.13
(Ø3.3)
8 PLACES

1.25
(31.8)

DETAIL B

LEGEND

in
(mm)
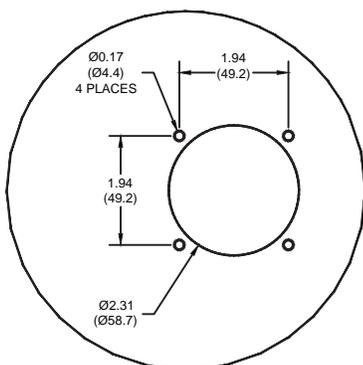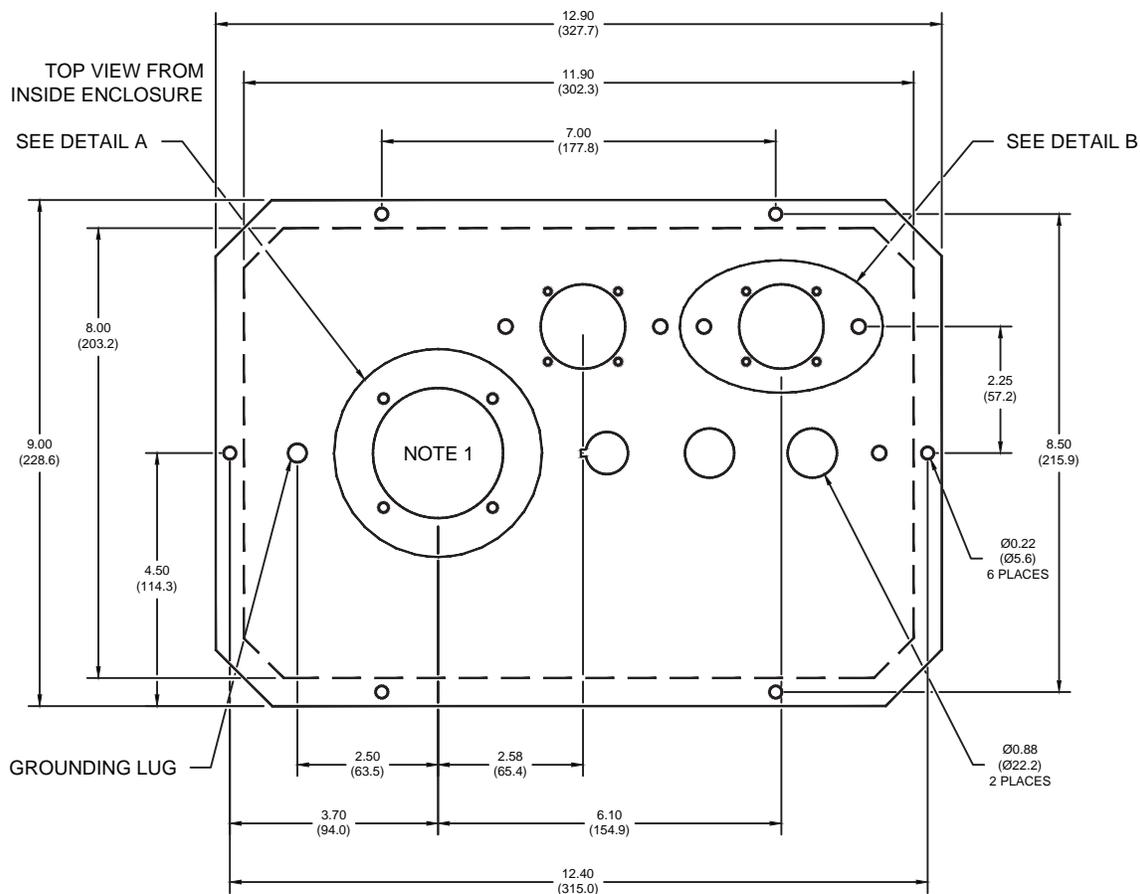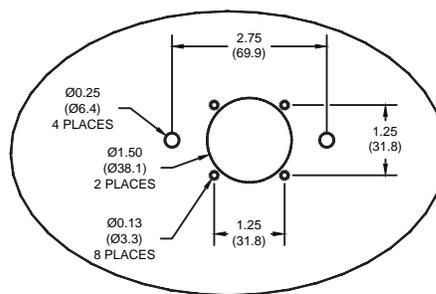
NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.14   Connector Panel at Bottom of Enclosure for ABB Joslyn TriMod 600R Recloser (Dual-Door Enclosure)

2.16 Installation
Installation Steps and Drawings

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TOP VIEW FROM
INSIDE ENCLOSURE

SEE DETAIL A

SEE DETAIL B

12.90
(327.7)

11.90
(302.3)

7.00
(177.8)

8.00
(203.2)

9.00
(228.6)

NOTE 1

4.50
(114.3)

2.25
(57.2)

8.50
(215.9)

Ø0.22
(Ø5.6)
6 PLACES

GROUNDING LUG

2.50
(63.5)

2.58
(65.4)

Ø0.88
(Ø22.2)
2 PLACES

3.70
(94.0)

6.10
(154.9)

12.40
(315.0)

Ø0.16
(Ø3.9)
4 PLACES

1.57
(39.8)

1.57
(39.8)

Ø1.87
(Ø47.5)

DETAIL A

2.75
(69.9)

Ø0.25
(Ø6.4)
4 PLACES

1.25
(31.8)

Ø1.50
(Ø38.1)
2 PLACES

Ø0.13
(Ø3.3)
8 PLACES

1.25
(31.8)

DETAIL B

LEGEND
in
(mm)

NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.15   Connector Panel at Bottom of Enclosure for Eaton NOVA-TS or NOVA-STS Triple-Single Recloser (Dual-Door Enclosure)

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TOP VIEW FROM
INSIDE ENCLOSURE

GROUNDING LUG

SEE DETAIL B

12.90
(327.7)

10.49
(266.3)

1.77
(44.9)

3.31
(84.0)

3.50
(88.9)

Ø0.88
(Ø22.2)
2 PLACES

8.00
(203.2)

9.00
(228.6)

2.25
(57.2)

NOTE 1

2.25
(57.2)

8.50
(215.9)

2.25
(57.2)

4.50
(114.3)

SEE DETAIL A

SEE DETAIL C

2.70
(68.6)

7.00
(177.8)

Ø0.22
(Ø5.6)
6 PLACES

2.97
(75.4)

12.40
(315.0)

Ø0.18
(Ø4.5)
4 PLACES

1.42
(36.0)

2.75
(69.9)

1.25
(31.8)

Ø0.25
(Ø6.2)
2 PLACES

2.56
(65.0)

Ø0.13
(Ø3.2)
4 PLACES

1.25
(31.8)

0.81
(20.6)

1.61
(41.0)

Ø1.50
(Ø38.1)

DETAIL B

Ø0.25
(Ø6.2)
3 PLACES

0.63
(16.0)

1.27
(32.2)

2.33
(59.2)

Ø0.25
(Ø6.2)
4 PLACES

2.75
(69.9)

DETAIL A

0.81
(20.6)

Ø0.94
(Ø23.8)
2 PLACES

Ø0.13
(Ø3.2)
8 PLACES

0.81
(20.6)

LEGEND

in
(mm)

NOTE 1: CONTROL CABLE INSTALLED HERE

DETAIL C

Figure 2.16   Connector Panel at Bottom of Enclosure for Tavrida OSM Al_2 and Multi-Recloser Interface (Dual-Door Enclosure)

2.18 Installation
Installation Steps and Drawings

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TOP VIEW FROM
INSIDE ENCLOSURE

SEE DETAIL A

12.90
(327.7)

11.90
(302.3)

7.00
(177.8)

SEE DETAIL B

Ø0.88
(Ø22.2)
2 PLACES

8.00
(203.2)

0.50
(12.7)

9.00
(228.6)

NOTE 1

2.25
(57.2)

8.50
(215.9)

2.00
(50.8)

4.50
(114.3)

GROUNDING LUG

1.63
(41.5)

3.07
(77.9)

4.00
(101.6)

SEE DETAIL C

Ø0.22
(Ø5.6)
6 PLACES

2.71
(68.8)

12.40
(315.0)

1.42
(36.0)

Ø0.25
(Ø6.2)
2 PLACES

3.03
(76.8)

2.03
(51.5)

3.39
(86.0)

0.81
(20.6)

Ø0.18
(Ø4.5)
4 PLACES

1.26
(32.0)

DETAIL A

2.75
(69.9)

Ø0.25
(Ø6.2)
4 PLACES

0.81
(20.6)

Ø0.94
(Ø23.8)
2 PLACES

0.81
(20.6)

Ø0.13
(Ø3.2)
8 PLACES

DETAIL B

2.75
(69.9)

Ø0.25
(Ø6.2)
4 PLACES

0.81
(20.6)

Ø0.88
(Ø22.3)
2 PLACES

0.81
(20.6)

Ø0.13
(Ø3.2)
8 PLACES

LEGEND

in

(mm)

DETAIL C

NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.17   Connector Panel at Bottom of Enclosure for Siemens SDR Triple-Single and Siemens SDR Three-Phase Reclosers (Dual-Door Enclosure)

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Wolfe

Dual-Door Accessory Shelf

An optional accessory shelf can be installed in the 19-inch rack, below the power module. It has predrilled holes and installed PEM nuts for the installation of various radios, protocol converters, and other accessories (see the dimensions in *Figure 2.18*). The accessory shelf takes up 8.9 cm (3.5 in, vertical) and can carry as much as 6.8 kg (15 lb).

LOCATION	PATTERN	THREAD TYPE	PRODUCT
A	2.5 x 2.5 (63.5 x 63.5)	Ø0.22 (Ø5.5)	Hole Pattern
B	5.75 x 0.75 (146.1 x 19.1)	6-32	Modem w/ Hat Bracket, Rover XT w/ Hat Bracket
C	4.90 (124.5)	6-32	SEL-2725
D	6.75 x 2.75 (171.5 x 69.85)	1/4-20	MDS 4710
E	3.675 (93.35)	6-32	SEL-2401, SEL-3031, Modem w/Bracket
F	8.5 x 3.75 (215.9 x 95.25)	10-32	
G	6.00 (152.4)	6-32	
H	2.60 x 3.00 (66.04 x 76.2)	Ø0.14 (Ø3.56)	
J	3.545 x 2.00 (90.04 x 50.8)	10-32	
K	7.60 (193.04)	Ø0.188 (Ø4.775)	

RACK-MOUNT SHELF

EQUIPMENT MOUNTS

i8070a

TOP

Ø0.22 (Ø5.5) TYP. GRID

2.50 (63.5) TYP.

1.25 (31.8)

2.50 (63.5) TYP.

LEGEND in (mm)

7.50 (193.1)

0.10 (2.5)

SIDE

3.47 (88.1)

1.75 (44.5)

FRONT

19.00 (482.6)

17.35 (440.4)

18.31 (465.1)

2.91 (73.8)

Figure 2.18   Accessory Shelf (Optional) (Dual-Door Enclosure)

2.20 | Installation
Installation Steps and Drawings

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Single-Door Control Mounting

⚠WARNING

Have only qualified personnel service this equipment. If you are not qualified to service this equipment, you can injure yourself or others, or cause equipment damage.

⚠WARNING

Take proper precautions to prevent personal injury or equipment damage when lifting and mounting the SEL-651R-2. Make sure doors are latched closed. Secure lifting attachments to the lifting holes. Lift slowly. Do not transport the SEL-651R-2 with the battery inside the enclosure.

⚠DANGER

If the recloser is energized while the control cable is disconnected from the recloser control, the CT secondaries in the control cable may generate dangerously high voltages. Do not come in contact with the pins or pin sockets in the control cable. Contact with high voltage can cause serious injury or death.

The drill plan detailed in *Figure 2.19* (37 inches on center) is the same as the traditional drill plan for double-size Eaton enclosures. If a retrofit of such an enclosure is taking place, no extra drilling of the pole or mounting structure is needed.

Mounting Bolts/Washers: SEL does not provide the 5/8-inch mounting bolt/washer assemblies required for mounting the SEL-651R-2. The mounting hole on the enclosure is 2 inches in diameter, so any washer used with the mounting bolt must be less than 2 inches in diameter.

The SEL-651R-2 has one 1.5-inch diameter lifting hole on each side of the enclosure.

Step 1. Secure lifting attachments to the lifting holes.

Step 2. Lift slowly.

Step 3. Slip the top mounting hole/keyway over the top mounting bolt/washer assembly.

Step 4. Rest the unit on the bolt, settled in the keyway slot.

Step 5. Secure the bottom mounting bracket with another mounting bottom bolt/washer assembly.

Step 6. Secure both top and bottom mounting bolt/washer assemblies.

The unit weighs (fully featured) 68 kg (≤150 lb), without the battery. Battery weights are given in *Table 2.2*.

Single-Door Drawings
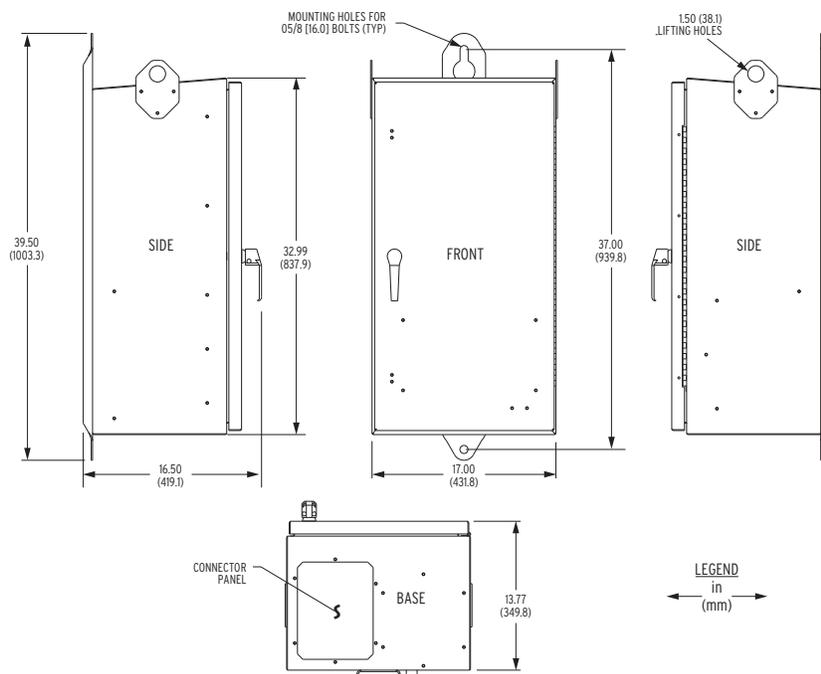
Figure 2.19 SEL-651R-2 Enclosure Dimensions and Mounting Drill Plan (Single-Door Enclosure)

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TOP VIEW FROM
INSIDE ENCLOSURE

GROUNDING LUG

10.00
(254.0)

9.00
(228.6)

0.75
(19.1)

5.50
(139.7)

NOTE 1

8.00
(203.2)

7.00
(177.8)

0.75
(19.1)

4.00
(101.6)

2.20
(55.9)

7.50
(190.5)

2.20
(55.9)

Ø0.88
(Ø22.4)
2 PLACES

Ø0.22
(Ø5.5)
6 PLACES

6.00
(152.4)

1.75
(44.5)

SEE DETAIL A

3.60
(91.4)

1.88
(47.6)

1.88
(47.6)

9.50
(241.3)

2.75
(69.9)

Ø0.25
(Ø6.4)
10 PLACES

1.25
(31.8)

Ø1.50
(Ø38.1)
5 PLACES

Ø0.13
(Ø3.3)
20 PLACES

1.25
(31.8)

LEGEND
in
(mm)

DETAIL A

NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.20   Connector Panel at Bottom of Enclosure for Traditional Retrofit, Control-Powered Eaton NOVA, and G&W Control Power Viper-S Reclosers (Single-Door Enclosure)

2.22 | Installation
Installation Steps and Drawings

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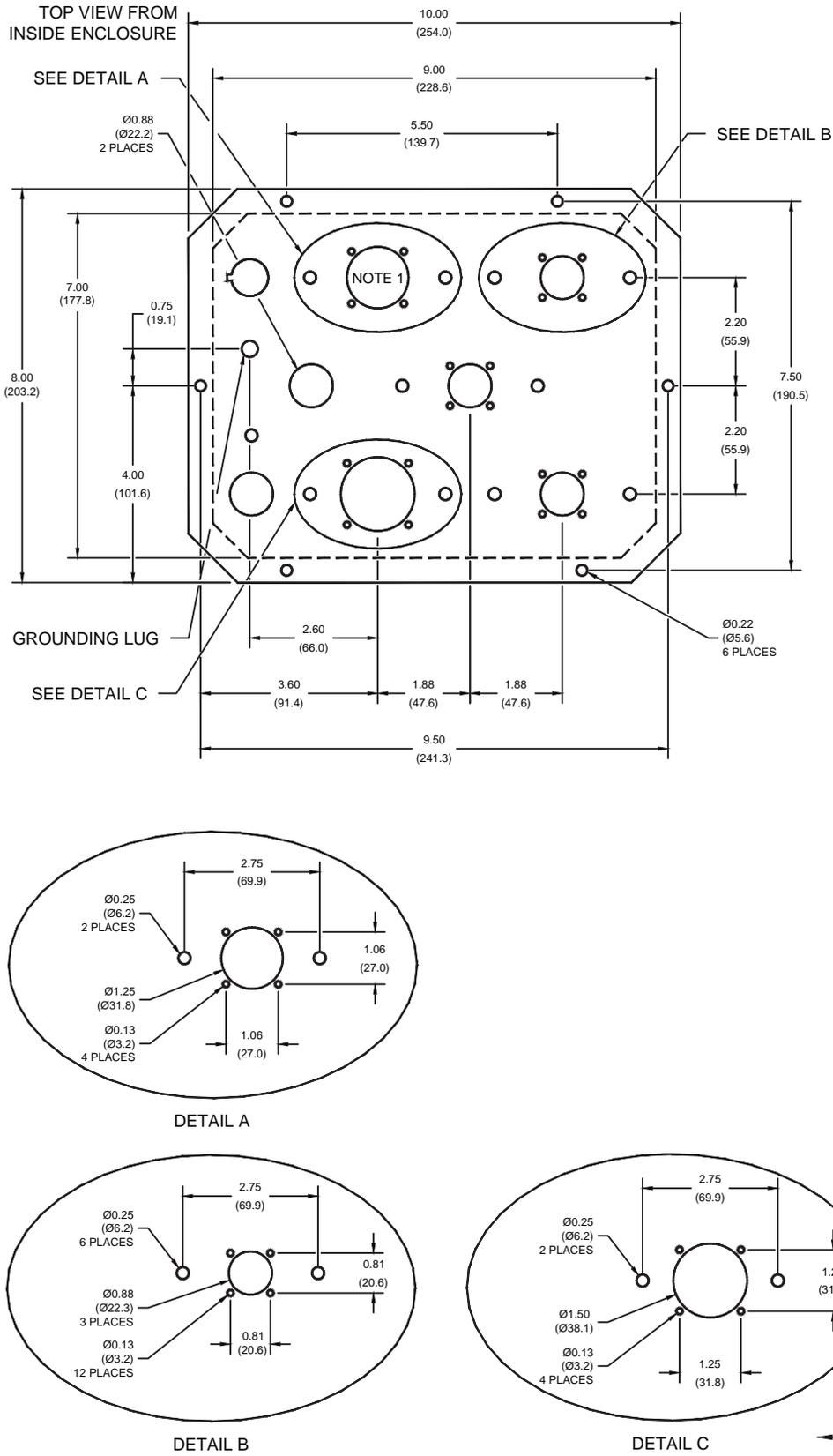
NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.21   Connector Panel at Bottom of Enclosure for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, and ABB OVR/Gridshield (32-Pin) Reclosers (Single-Door Enclosure)

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Installation | 2.23
Installation Steps and Drawings
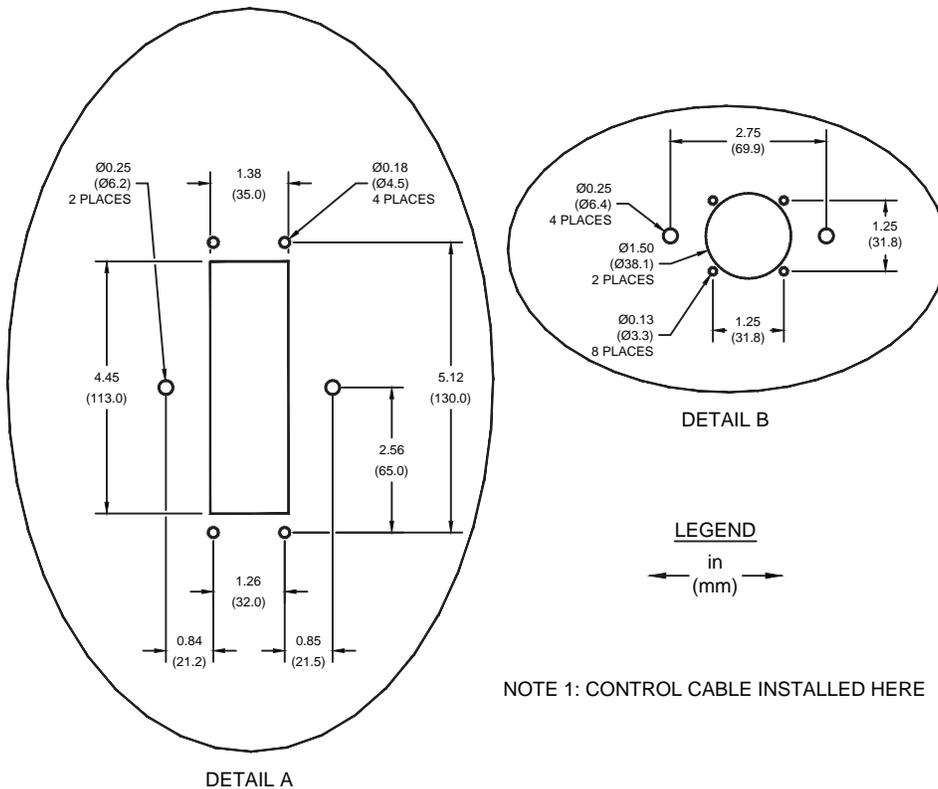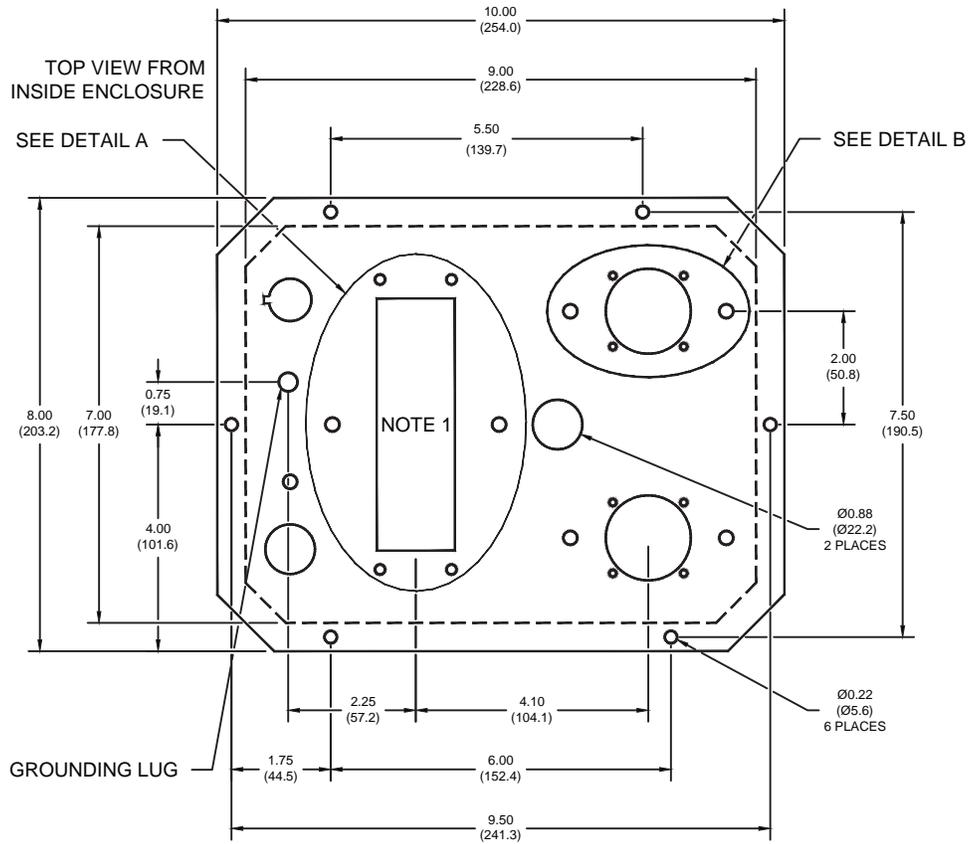
Figure 2.22   Connector Panel at Bottom of Enclosure for ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Recloser (Single-Door Enclosure)

2.24 | Installation
Installation Steps and Drawings

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TOP VIEW FROM
INSIDE ENCLOSURE

SEE DETAIL A

SEE DETAIL B

10.00
(254.0)

9.00
(228.6)

1.75
(44.5)

5.50
(139.7)

7.00
(177.8)

0.75
(19.1)

8.00
(203.2)

2.00
(50.8)

7.50
(190.5)

2.00
(50.8)

NOTE 1

4.00
(101.6)

GROUNDING LUG

2.24
(56.8)

Ø0.22
(Ø5.6)
6 PLACES

Ø0.88
(Ø22.2)
3 PLACES

3.24
(82.2)

4.11
(104.5)

1.75
(44.5)

6.00
(152.4)

9.50
(241.3)

DETAIL A

1.94
(49.2)

Ø0.17
(Ø4.4)
4 PLACES

1.94
(49.2)

Ø2.31
(Ø58.7)

DETAIL B

2.75
(69.9)

Ø0.25
(Ø6.4)
4 PLACES

1.25
(31.8)

Ø1.50
(Ø38.1)
2 PLACES

Ø0.13
(Ø3.3)
8 PLACES

1.25
(31.8)

LEGEND

in
(mm)

NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.23   Connector Panel at Bottom of Enclosure for ABB Joslyn TriMod 600R Recloser (Single-Door Enclosure)

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Installation 2.25
Installation Steps and Drawings

TOP VIEW FROM
INSIDE ENCLOSURE

SEE DETAIL A

SEE DETAIL B

NOTE 1

Ø0.22
(Ø5.6)
6 PLACES

Ø0.88
(Ø22.2)
2 PLACES

GROUNDING LUG

DETAIL A

Ø0.16
(Ø3.9)
4 PLACES

Ø1.87
(Ø47.5)

DETAIL B

Ø0.25
(Ø6.4)
4 PLACES

Ø1.50
(Ø38.1)
2 PLACES

Ø0.13
(Ø3.3)
8 PLACES

LEGEND

in
(mm)
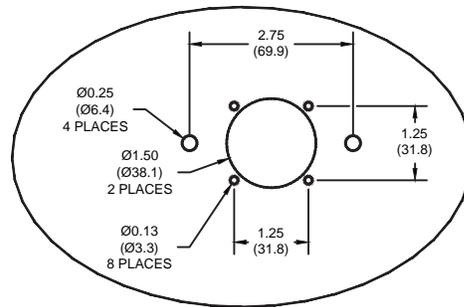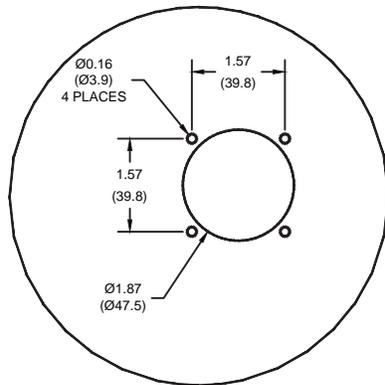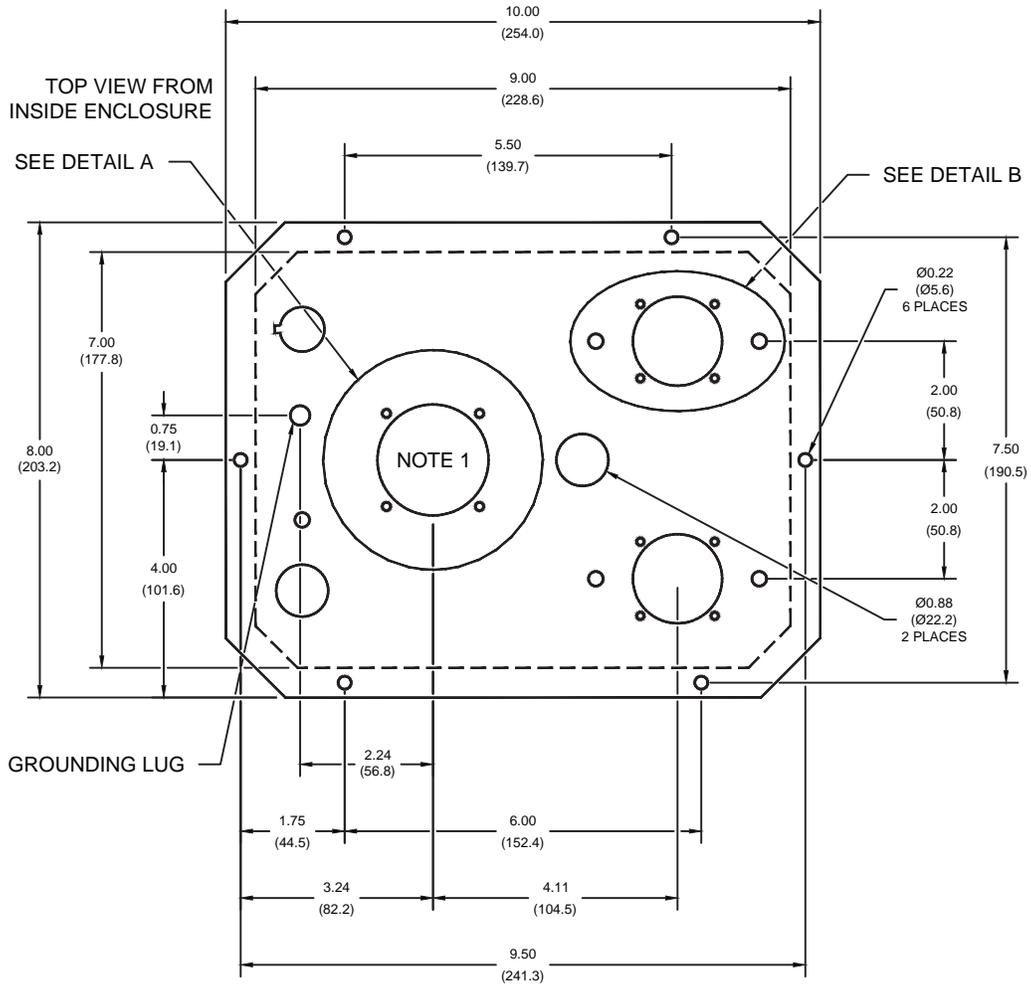
NOTE 1: CONTROL CABLE INSTALLED HERE

Figure 2.24   Connector Panel at Bottom of Enclosure for Eaton NOVA-TS or NOVA-STS Triple-Single Recloser (Single-Door Enclosure)

2.26 Installation
Installation Steps and Drawings

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TOP VIEW FROM
INSIDE ENCLOSURE

GROUNDING LUG

SEE DETAIL B

NOTE 1

SEE DETAIL A

DETAIL A

DETAIL B

LEGEND

in
(mm)

NOTE 1: CONTROL CABLE INSTALLED HERE

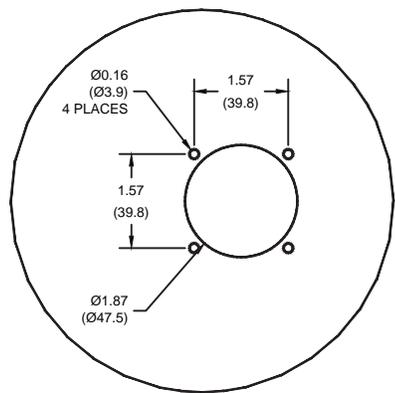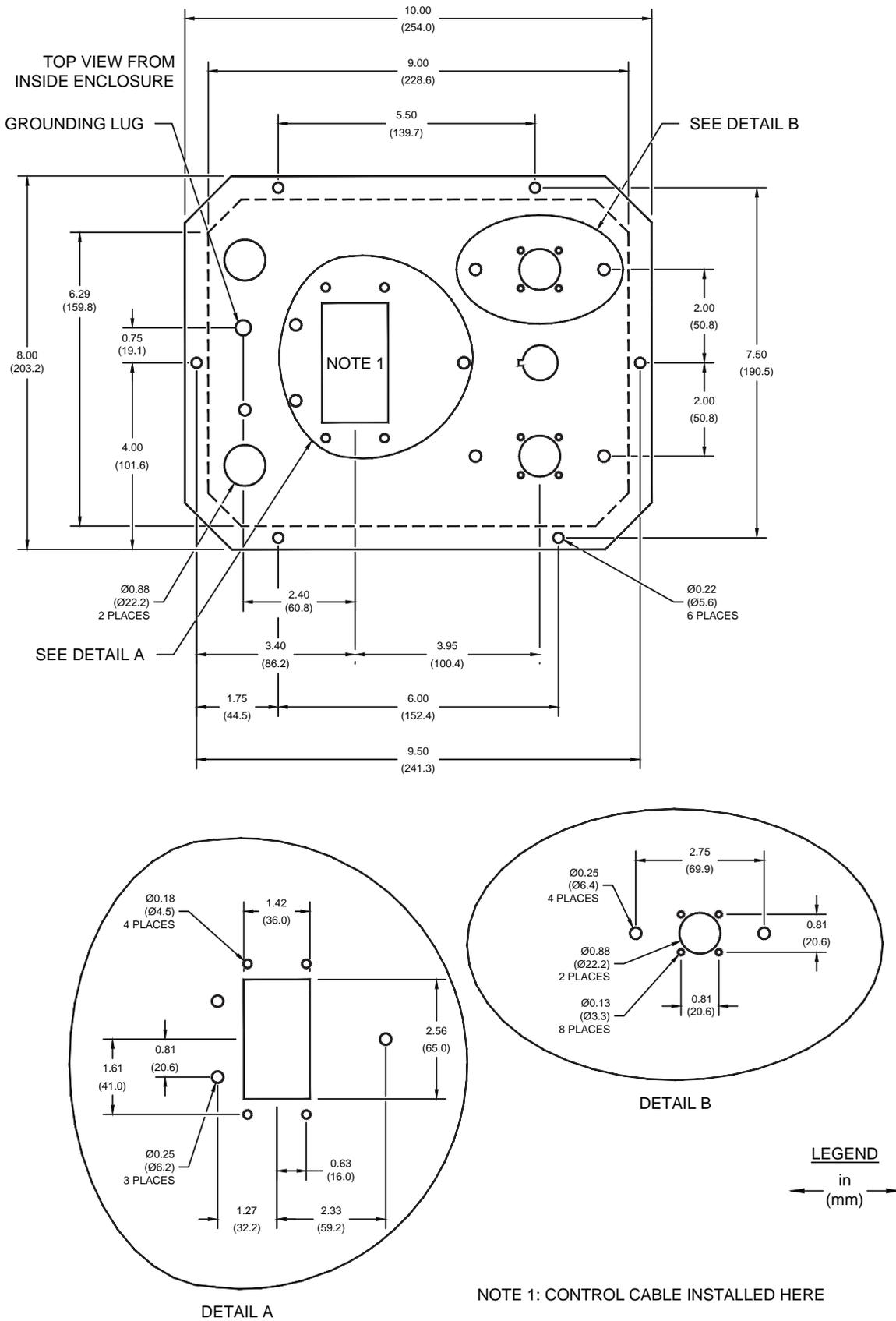**Figure 2.25   Connector Panel at Bottom of Enclosure for Tavrida OSM AI_2 and Multi-Recloser Interface (Single-Door Enclosure)**

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Installation 2.27
Installation Steps and Drawings
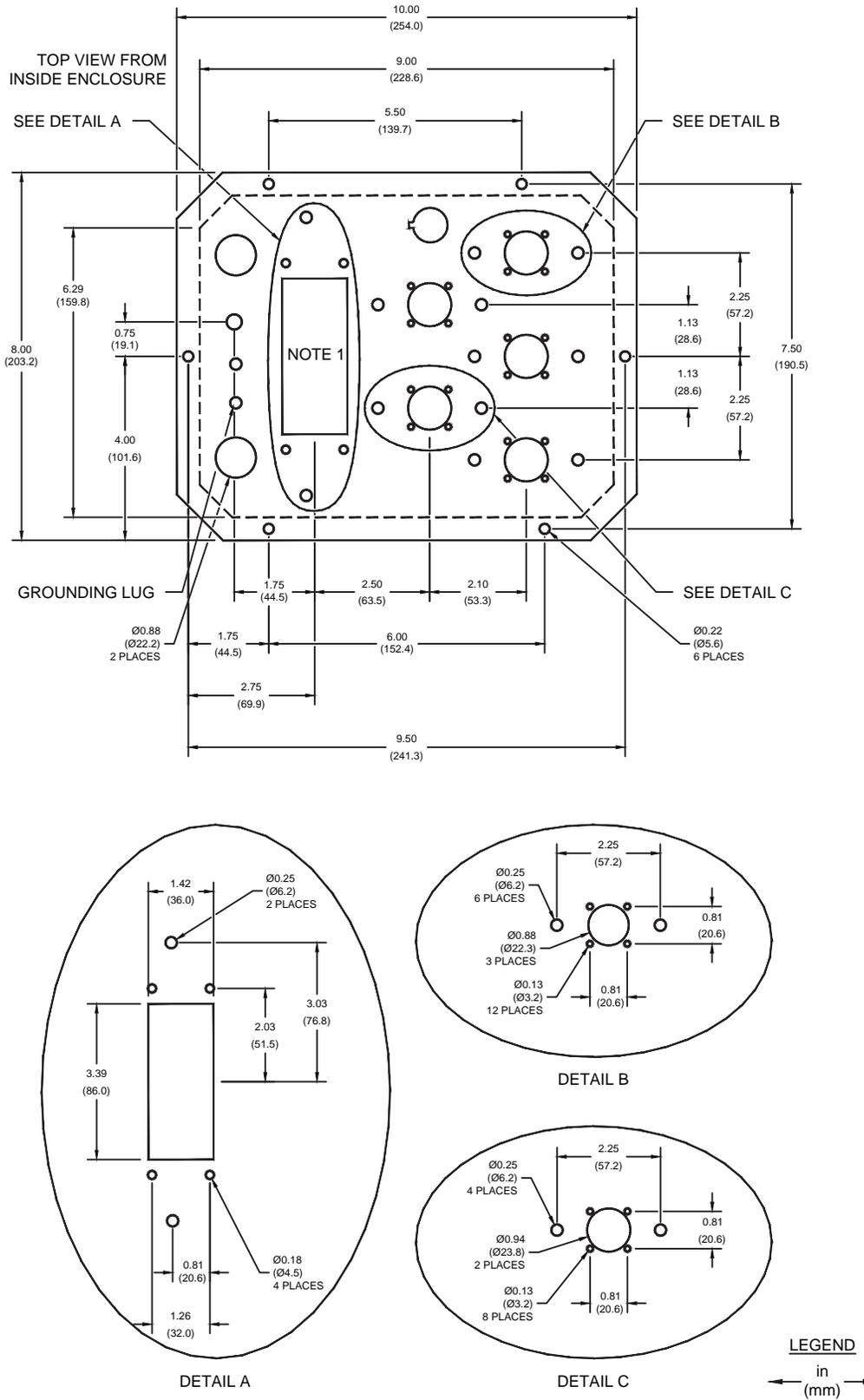
Figure 2.26 Connector Panel at Bottom of Enclosure for Siemens SDR Triple-Single and Siemens SDR Three-Phase Reclosers (Single-Door Enclosure)

2.28 | Installation
Installation Steps and Drawings

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Single-Door Accessory Shelf

An optional accessory shelf can be installed in the enclosure, below the relay and power modules. It has predrilled holes and installed PEM nuts for the installation of various radios, protocol converters, and other accessories (see the dimensions in *Figure 2.27*).

LOCATION	PATTERN	THREAD TYPE	PRODUCT
A	10.63 x 3.94 (270.0 x 100.0)	M5x0.8	Top Hat Return
B	5.75 x 0.75 (146.1 x 19.1)	6-32	Modem w/ Hat Bracket, Rover XT w/ Hat Bracket
C	3.468 x 5.25 (88.09 x133.4)	6-32	Silver Springs
D	4.50 x 3.75 (114.3 x 95.25)	6-32	Telemetric
E	3.675 (93.35)	6-32	SEL-2401, SEL-3031, Modem w/Bracket
F	4.25 X 2.50 (107.95 x 63.50)	Ø0.156 (Ø3.96)	MDS 9710
G	4.00 x 3.342 (101.6 x 84.89)	Ø0.203 (Ø5.16)	
H	7.342 x 4.00 (186.49 x 101.6)	Ø0.203 & Ø0.188 (Ø5.16 & Ø4.775)	Rugged Com
J		Ø0.188 (Ø4.775)	Surge Suppressor
K	2.60 x 3.00 (66.04 x 76.2)	Ø0.14 (Ø3.56)	
L	4.90 (124.5)	6-32	SEL-2725
M	3.938 x 5.438 (100.025 x 138.125)	Ø0.188 (Ø4.775)	Utilinet
N	4.28 x 2.50 (108.7 x 63.5)	Ø0.1563 (Ø3.97)	MDS 4710
P	3.675 (93.345)	6-32	SEL-2401, SEL-3031, Modem w/Bracket

Figure 2.27   Accessory Shelf (Optional) (Single-Door Enclosure)

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Installation 2.29
Installation Steps and Drawings

Control Grounding

Figure 2.28   SEL-651R-2 Recloser Control Customer Ground Connection to Required System Grounding
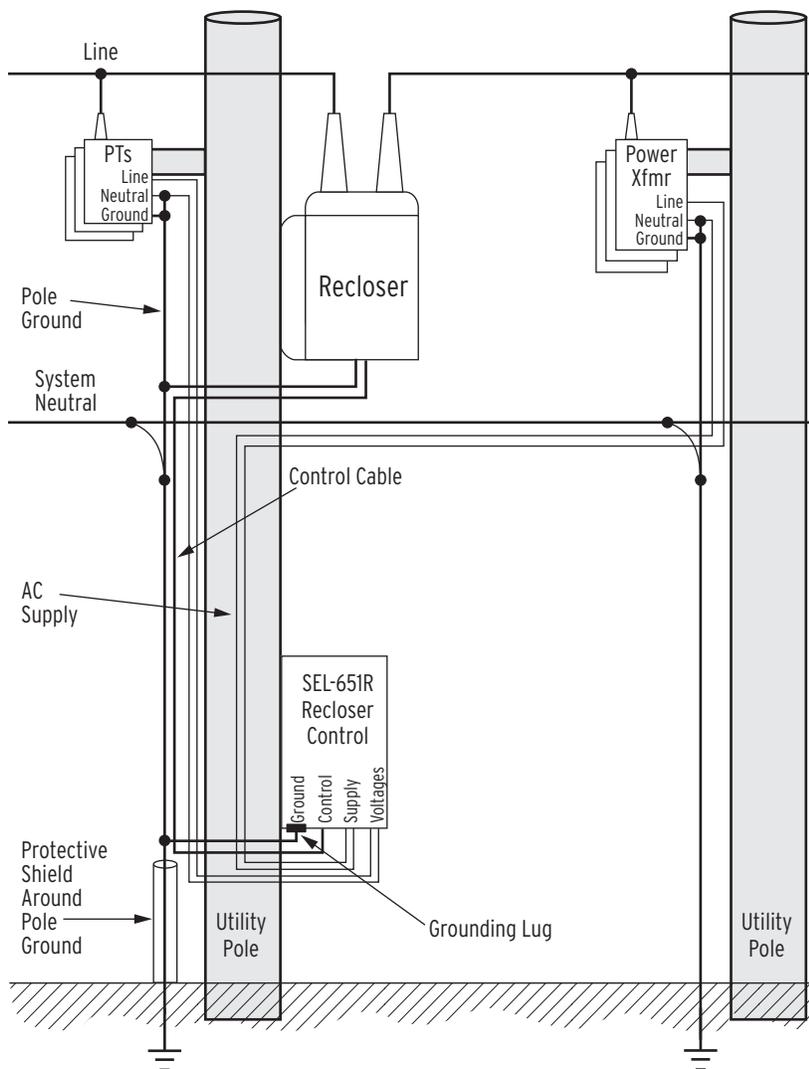
IMPORTANT: All devices interfacing to the SEL-651R-2 recloser control must be connected to the same pole ground. Figure 2.28 shows a suggested method of making these connections.

IMPORTANT: All connections to the SEL-651R-2 recloser control must be routed in close proximity to and parallel to their corresponding ground paths for adequate surge protection. The connections and their ground paths should be approximately equal in length. Use applicable IEEE and IEC grounding standards. Follow the proceeding recommendations to reduce high potentials from surges that can damage equipment.

Step 1.   Connect the pole ground to the grounding lug on the bottom of the recloser control enclosure as shown in *Figure 2.28*.

The grounding lug accommodates No. 10–No. 4 conductors (solid or stranded) (as many as two No. 4). A protective shield around the pole ground is suggested to help prevent physical damage to the ground wire, such as preventing an open circuit.

Step 2.   Ground all devices interfacing to the recloser control at the same pole ground.

Devices include: recloser, power transformer, potential transformers/voltage transducers, and SCADA. Even devices on adjacent poles with their own pole ground (e.g., power transformer) must still connect to the pole ground for the recloser control.

Step 3.   Route the control cable in close proximity to and parallel with the recloser ground.

Step 4.   Route ac supply voltage (power) and power system voltages in parallel with their transformer ground paths.

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Installation Steps and Drawings

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GROUNDING INSIDE ENCLOSURE

As referenced in the accompanying steps, all grounding inside the enclosure should be brought to the 5/16-inch diameter bolt that protrudes through the floor of the enclosure. On the outside of the enclosure, this bolt is integral to the grounding lug shown in Figure 2.28 and discussed in the first steps of this subsection (Control Grounding).

ENCLOSURE OPENINGS

No openings into the SEL-651R-2 enclosure should be left uncovered, with the exception of the vented hole plugs provided by SEL. Any conduit or other wire entry must be properly sealed.

Battery Installation and Connection

⚠ **CAUTION**

The Quick disconnect shown in Figure 2.29 should be the **first** connection pulled apart (disconnected) when removing the battery, and the **last** connection pushed together (connected) when installing the battery. Do not leave the battery wiring harness connected via the Quick Disconnect without the battery also connected to the battery wiring harness. This prevents the energized battery wiring harness positive (+; red) and negative (−; black) terminals from short-circuiting by coming in contact with the enclosure floor or each other.

Step 5. Bring all points inside the enclosure that require grounding (e.g., shielding on wires connected to inputs **IN101**–**IN107** or output contacts **OUT101**–**OUT108**; radio chassis) to the 5/16-inch diameter bolt that protrudes through the floor of the enclosure.

Make sure these grounding connections are secure.

Note that the relay module and power module are both grounded inside the enclosure at this protruding 5/16-inch diameter bolt.

Step 6. When installing the recloser control and recloser, include the following according to the manufacturers' recommendations:

➢ Protection of the recloser and the power transformer with lightning arresters.

➢ Grounding of the recloser head and tank.

➢ Grounding of the power transformer tank.

➢ Grounding of the control cabinet.
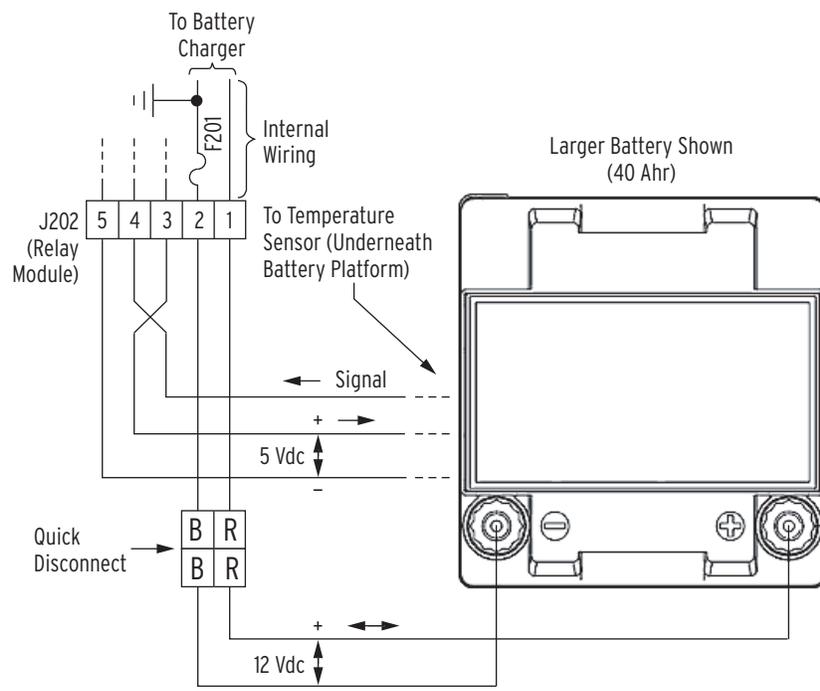
Figure 2.29   Battery Wiring Harness Connections (Shown Connected to Relay Module)

Step 1. Follow any manufacturer installation recommendations and warnings for the battery.

Step 2. Pull apart (disconnect) the Quick Disconnect shown in *Figure 2.29*, if not already separated (see ⚠).

Step 3. Connect the piece of the now separated battery harness with Connector J202 into corresponding receptacle **J202** on the relay module (if not already connected). The Quick Disconnect should still be pulled apart (disconnected).

Step 4. Outside the enclosure, connect the other piece of the battery harness piece to the 12 V battery, following the manufacturer's torque recommendations. The positive (**+**) battery terminal

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connects to the terminal of the red wire. The negative (–) battery terminal connects to the terminal of the black wire. The Quick Disconnect should still be pulled apart (disconnected).

Step 5. Inside the enclosure, unbuckle and move the two side-release buckle straps so that the raised battery platform is clear.

The straps should already be fitted underneath the slots provided on the raised platform, one strap oriented in one horizontal dimension and the other strap in the other horizontal dimension.

Step 6. Set the 12 V battery on the raised battery platform, with the terminals up and oriented toward the center of the enclosure.

Step 7. Fasten and secure the two side-release buckle straps over the battery, keeping the battery terminals clear.

Step 8. Push together (connect) the Quick Disconnect and ensure that it is fully engaged. Notice that making this last connection does not yet energize or turn on the control.

Proceed to *Wake Up* to turn on the control by using the **WAKE UP** pushbutton. The front panel will remain dark until you press the **WAKE UP** pushbutton.

See *Battery and Fuse Replacement on page 2.57* for more battery information.

See *Battery System Monitor on page 8.39* for help on testing the battery.

⚠**WARNING**

Do not transport the SEL-651R-2 with the battery inside the enclosure.

Wake Up

With the battery installed, press the front-panel **WAKE UP** pushbutton to energize the SEL-651R-2.

➤ If the unit turns on, the **ENABLED** LED illuminates and the **BATTERY PROBLEM** LED remains extinguished.

➤ If the unit does not turn on, check the following items:

➢ Battery condition.

➢ Battery fuse (panel-mount fuse F201 on the rear panel of the relay module, next to separable connector J202). See *Figure 2.29* and *Table 2.3*.

Note that application of Vac power (120 or 230 Vac, depending on unit) always energizes the SEL-651R-2.

Power Supply Connections

Order the power supply of the SEL-651R-2 at one of the following nominal voltage levels:

➤ 120 Vac (includes a Ground-Fault Circuit Interrupter [GFCI] convenience outlet on the front)

➤ 230 Vac

➤ 125 Vdc

➤ 48 Vdc

The serial number label lists the power supply rating. *Figure 2.30*, *Figure 2.31*, *Figure 2.32*, and *Figure 2.33* show the simplest 120 Vac, 230 Vac, 125 Vdc, and 48 Vdc power connections, respectively. These connections are made in the upper-right corner of the rear panel of the power module (dual-door enclosure, *Figure 2.3*) or below the front panel (single-door enclosure, *Figure 2.8*). Note that fuse protection is provided for all scenarios. The fuse blocks have integral fuse pullers, for ease of safely

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NOTE: When 120 Vac (or 230 Vac, depending on ordered unit) power is correctly connected to the SEL-651R-2, the front-panel **SUPPLY** LED illuminates. If it is still extinguished, check fuse F412 (for the 120 Vac power supply) or both fuses F407 and F408 (for the 230 Vac power supply)—see Table 2.3. The **SUPPLY** LED illuminates if the relay module is powered-up/functional and the battery is not discharging. The **SUPPLY** LED may flicker at times when tripping or closing, because of the battery momentarily discharging.

The connected 120 Vac (or 230 Vac) power source is isolated from the power module chassis ground.

120 VAC (GFCI) CONVENIENCE OUTLET WIRING FOR SINGLE-DOOR ENCLOSURE UNITS
In single-door enclosure units (see Figure 2.6, lower right of open enclosure), the 120 Vac (GFCI) convenience outlet is wired externally to power module terminals C02 and C03. It does not use fuse F411 internal wiring as shown in Figure 2.30 (for dual-door enclosure units, see Figure 2.1). The external 120 Vac (GFCI) convenience outlet for single-door enclosure units is protected with a separate external fuse (unlabeled) of the same value as fuse F411 (see Table 2.3).

removing/installing fuses. Pull these fuses to de-energize/isolate the modules, although battery power can still keep the modules on. Fuse values are given in *Table 2.3*.

For additional 120 Vac power supply accessory options see *120 Vac Power Supply Connection Options and Accessories on page 2.37*.
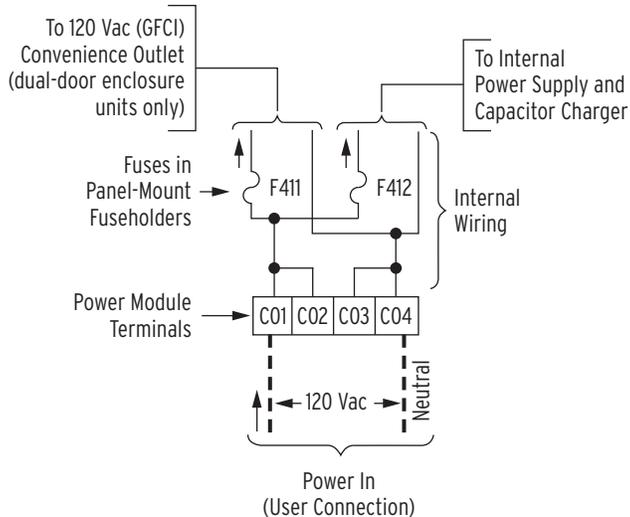
Figure 2.30   120 Vac Power Connection

For the 120 Vac connection, the screws on terminals C01 and C04 are #10-32 (use max. width 11.4 mm [0.45 in] ring terminals; tightening torque of 1.0 to 2.0 Nm [9 to 18 in-lb]).

The 120 Vac power option has other possible connection options and accessories, detailed in *Figure 2.35–Figure 2.40*.
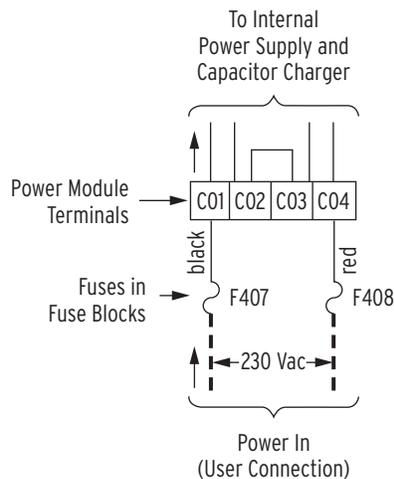
Figure 2.31   230 Vac Power Connection

For the two-wire 230 Vac connection, the screws on fuse blocks F407 and F408 are #10-32 (use max. width 11.4 mm [0.45 in] ring terminals; tightening torque of 1.0 to 2.0 Nm [9 to 18 in-lb]).

The 230 Vac power option has only the connection in *Figure 2.31*. No front-panel GFCI convenience outlet is provided with the 230 Vac power option.

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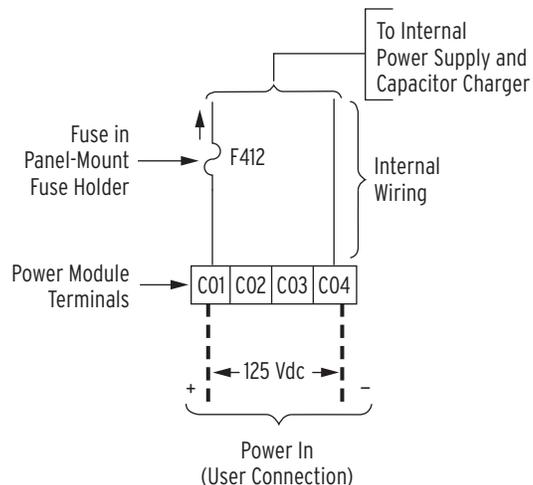
Figure 2.32   125 Vdc Power Connection

For the 125 Vdc connection, the screws on terminals C01 and C04 are #10-32 (use max. width 11.4 mm [0.45 in] ring terminals; tightening torque of 1.0 to 2.0 Nm [9 to 18 in-lb]).

The 125 Vdc power option has only the connection in *Figure 2.32*. No front-panel GFCI convenience outlet is provided with the 125 Vdc power option.
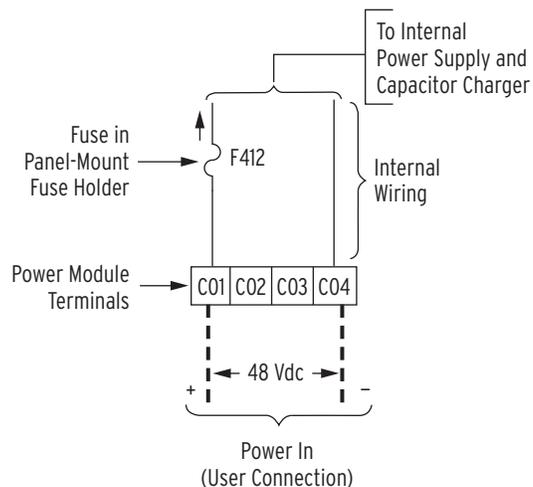
Figure 2.33   48 Vdc Power Connection

For the 48 Vdc connection, the screws on terminals C01 and C04 are #10-32 (use max. width 11.4 mm [0.45 in] ring terminals; tightening torque of 1.0 to 2.0 Nm [9 to 18 in-lb]).

The 48 Vdc power option has only the connection in *Figure 2.33*. No front-panel GFCI convenience outlet is provided with the 48 Vdc power option.

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Verify Settings/Set Date and Time

Note that this step presumes that the factory-set **ALTERNATE SETTINGS** operator control is operative.

Step 1. If the alternate settings are not going to be used, copy the main settings (Settings Group 1) to the alternate settings (Settings Group 2) with the **COPY** command (i.e., **COP 1 2**).

The settings in both settings groups will then be the same. If the **ALTERNATE SETTINGS** operator control pushbutton is accidentally pressed (switching the active settings group), the SEL-651R-2 still operates on the same settings.

Step 2. Set the date and time with the **DATE** and **TIME** commands (**DAT** and **TIM**, respectively).

⚠CAUTION

Do not connect the SEL-651R-2 to an energized recloser until all control settings have been properly programmed and verified. Failure to comply can result in control and recloser misoperation, equipment damage, and personal injury.

Disable Ground

Note that this step presumes that the factory-set **GROUND ENABLED** operator control is operative.

Disable ground overcurrent tripping with the **GROUND ENABLED** operator control on the SEL-651R-2 (corresponding LED extinguishes). Set other operator controls as desired for normal operation or whatever your standard commissioning procedure dictates.

Connect the Control Cable

Note that the control cable carries the currents among other signals, between the recloser and the SEL-651R-2. The phase current inscriptions for terminals Z01–Z06 in *Figure 2.5* and *Figure 2.9* (I1, I2, I3) have no permanent A-, B-, or C-phase designation. Phase designation is determined by Global setting IPCONN. See *Current Connection Setting (IPCONN) on page 9.28* for more information on this setting.

The SEL-651R-2 can be ordered with only one control cable receptacle (for connection to the desired recloser). This interface cannot be changed in the field.

The following help identify the control cable receptacle at the bottom of the SEL-651R-2 enclosure to which the control cable should be connected:

➤ The applicable figure of the connector panel at the bottom of the enclosure (see *Figure 2.11–Figure 2.26*)

➤ The pinout of the applicable control cable receptacle (see *Figure 2.34*)

⚠DANGER

If the recloser is energized while the control cable is disconnected from the recloser control, the CT secondaries in the control cable may generate dangerously high voltages. Do not come in contact with the pins or pin sockets in the control cable. Contact with high voltage can cause serious injury or death.

Presuming that the control cable is already connected to the recloser, connect the other end to the control cable receptacle at the bottom of the SEL-651R-2 enclosure. Pay attention to possible keying of the cable end and receptacle for proper connection.

Figure 2.34 shows the pinouts for the available control cable receptacles (view from inside enclosure). The common uses for the different pins are shown in the following figures:

➤ Traditional Retrofit control cable: *Figure 2.49* and *Figure 2.50*

➤ G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-pin) control cable: *Figure 2.43*, *Figure 2.52*, *Figure 2.53*, and *Figure 2.54*

➤ ABB OVR-3/VR-3S (24-pin,15 and 27 kV models) control cable: *Figure 2.55*, *Figure 2.56*, and *Figure 2.57*

➤ Control-Powered Eaton NOVA or G&W Control Power Viper-S control cable: *Figure 2.59* and *Figure 2.60*

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➤ ABB Joslyn TriMod 600R control cable: *Figure 2.62*, *Figure 2.63*, and *Figure 2.64*

➤ Eaton NOVA-TS or NOVA-STS Triple-Single control cable: *Figure 2.65*, *Figure 2.66*, and *Figure 2.67*

➤ Tavrida OSM Al_2 control cable: *Figure 2.68* and *Figure 2.69*

➤ Siemens SDR Triple-Single control cable: *Figure 2.70*, *Figure 2.72*, and *Figure 2.74*

➤ Siemens SDR Three-Phase control cable: *Figure 2.71*, *Figure 2.73*, and *Figure 2.75*

➤ Multi-Recloser Interface control cable: *Figure 2.76*, *Figure 2.77*, *Figure 2.79*, and *Figure 2.80*

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14-Pin Control Cable Receptacle for
Traditional Retrofit Recloser

32-Pin Control Cable Receptacle for G&W Viper-ST,
G&W Viper-LT, ABB Elastimold MVR, or ABB
OVR/Gridshield Recloser

Rear Door of Enclosure

View From Inside Enclosure

Front Door of Enclosure

24-Pin Control Cable Receptacle for ABB OVR-3/VR-3S
(15 and 27 kV models) Recloser

19-Pin Control Cable Receptacle for Control-Powered
Eaton NOVA or G&W Control Power Viper-S Recloser

Rear Door of Enclosure

View From Inside Enclosure

Front Door of Enclosure

27-Pin Control Cable Receptacle
for ABB Joslyn TriMod 600R Recloser

26-Pin Control Cable Receptacle for Eaton
NOVA-TS or NOVA-STS Triple-Single Recloser

Rear Door of Enclosure

View From Inside Enclosure

Front Door of Enclosure

32-Pin Control Cable Receptacle
for Tavrida OSM AI_2 Recloser

40-Pin Control Cable Receptacle
for Siemens SDR Reclosers

Rear Door of Enclosure

View From Inside Enclosure

Front Door of Enclosure

42-Pin Control Cable Receptacle
for Multi-Recloser Interface

Rear Door of Enclosure

View From Inside Enclosure

Front Door of Enclosure

Figure 2.34   Control Cable Receptacle Pinouts

Metering Check

Step 1.   Using the front-panel LCD and navigation buttons, go to the fundamental (instantaneous) metering screens.

Step 2.   Scroll through the fundamental metering values (primary), checking current IA, IB, and IC magnitude and angle for expected phase rotation.

The ground (IG) and neutral (IN) current displays should show relatively low current magnitudes, when compared to IA, IB, and IC, if system loading is well-balanced. The

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negative-sequence (3I2) current display should show relatively low current magnitude, when compared to IA, IB, and IC, if system loading is well-balanced and phase rotation is correct.

Step 3. If system loading is well-balanced, but current display 3I2 shows an abnormally high current level (i.e., at a level near the phase current levels or above), suspect a wiring problem or setting problem (see settings listed below).

    a. Solve this problem before enabling ground overcurrent tripping.

    b. This may require taking the SEL-651R-2 out of service.

Step 4. Do similar checks for the voltage connections with the instantaneous metering screens, comparing phase voltages VAY, VBY, VCY (VY-side) and VAY, VBY, VCY (VZ-side) with corresponding negative-sequence voltage values (V2Y and V2Z). If system voltage (VY-side or VZ-side) is well-balanced, but the corresponding negative-sequence voltage (V2Y or V2Z) shows an abnormally high voltage level, such as a level near the phase voltage levels, suspect a wiring problem or setting problem (see settings listed below).

Check current and voltage-connection Global settings IPCONN, VYCONN, and VZCONN in case of problems (see *Table 9.8* and *Table 9.9*).

Step 5. Check the phase rotation setting, too (Global setting PHROT). *Figure 2.49*, *Figure 2.52*, *Figure 2.55*, *Figure 2.59*, *Figure 2.62*, *Figure 2.65*, *Figure 2.68*, *Figure 2.70*, *Figure 2.71*, *Figure 2.76*, and *Figure 2.77* show current connections. *Figure 2.41*, *Figure 2.42*, *Figure 2.43*, *Figure 2.44*, *Figure 2.45*. *Figure 2.52*, *Figure 2.55*, *Figure 2.65*, *Figure 2.68*, *Figure 2.70*, *Figure 2.71*, *Figure 2.76*, and *Figure 2.77* show voltage connections.

Enable Ground

Again, note that this step presumes that the factory-set **GROUND ENABLED** operator control is operative.

If desired for normal operation, enable ground overcurrent tripping with the **GROUND ENABLED** operator control on the SEL-651R-2 (corresponding LED illuminates), or whatever your standard commissioning procedure dictates.

This is the last of the basic installation steps. Information on extra connections and supporting material follow.

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120 Vac Power Supply Connection Options and Accessories

Figure 2.35–Figure 2.40 show additions to the simple 120 Vac power connection in *Figure 2.30*. The Universal Fuse Block, AC Transfer Switch, 3-Pin Power Receptacle, and Low-Voltage Close accessories, discussed herein, can be installed on a 120 Vac powered unit.

Universal Fuse Block

The Universal Fuse Block in *Figure 2.35* appears to provide redundant fusing (fuse F407 in line with fuses F411 and fuse F412). But, with the addition of the low-voltage (120 Vac) close option for Traditional Retrofit reclosers (see

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Figure 2.40), the Universal Fuse Block provides protection for this effective 120 Vac exposure going out to the recloser. The Universal Fuse Block is mounted near the center of the rear panel of the power module. The fuse blocks have integral fuse pullers, for ease of safely removing or installing fuses. Fuse values are given in *Table 2.3*.
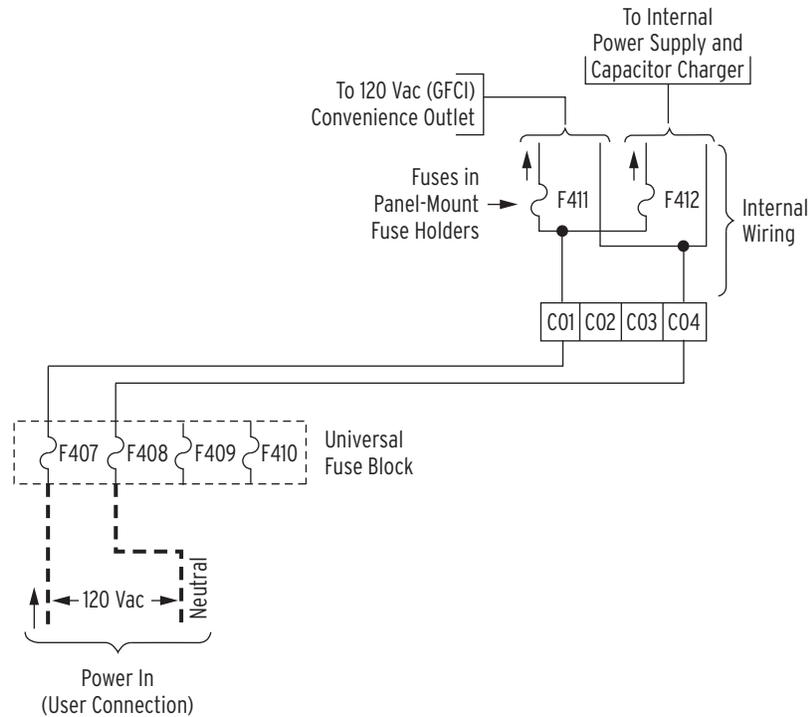
Figure 2.35   Universal Fuse Block Power Connection

For the Universal Fuse Block connection, the screws on fuse blocks F407–F410 are #10-32. Use max. width 11.4 mm (0.45 in) ring terminals; tightening torque of 1.0 to 2.0 Nm (9 to 18 in-lb).

AC Transfer Switch

The AC Transfer Switch in *Figure 2.36* is used in automatic network reconfigurations, to switch the SEL-651R-2 to an alternate source of power if the primary source is unavailable. Two separate 120 Vac power sources are brought to the Transfer Switch. The Transfer Switch is a break-before-make switch, so the two 120 Vac power sources are never paralleled. The Transfer Switch is mounted on the right side of the rear panel of the power module.

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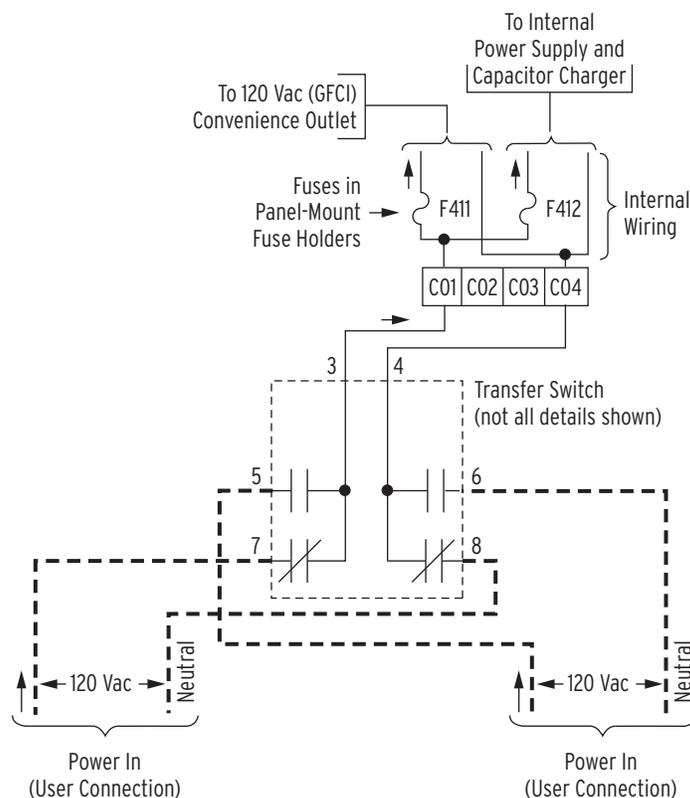
Figure 2.36 AC Transfer Switch Power Connections

For the Transfer Switch connection, the screws on the Transfer Switch terminals (numbered 1–8) are #10-32 (use max. width 11.4 mm [0.45 in] ring terminals; tightening torque of 1.0 to 2.0 Nm [9 to 18 in-lb]).

Figure 2.37 shows the combination of the Universal Fuse Block and the Transfer Switch, with the Universal Fuse Block providing fuse protection for the Transfer Switch and every 120 Vac circuit beyond it.

120 Vac power sources for recloser controls are typically provided by dedicated distribution power transformers (e.g., 5 kVA), mounted on adjacent poles/structures (see *Figure 2.28*). *Figure 2.41* and *Figure 2.43* in the following subsection show other possible wiring to provide 120 Vac power.

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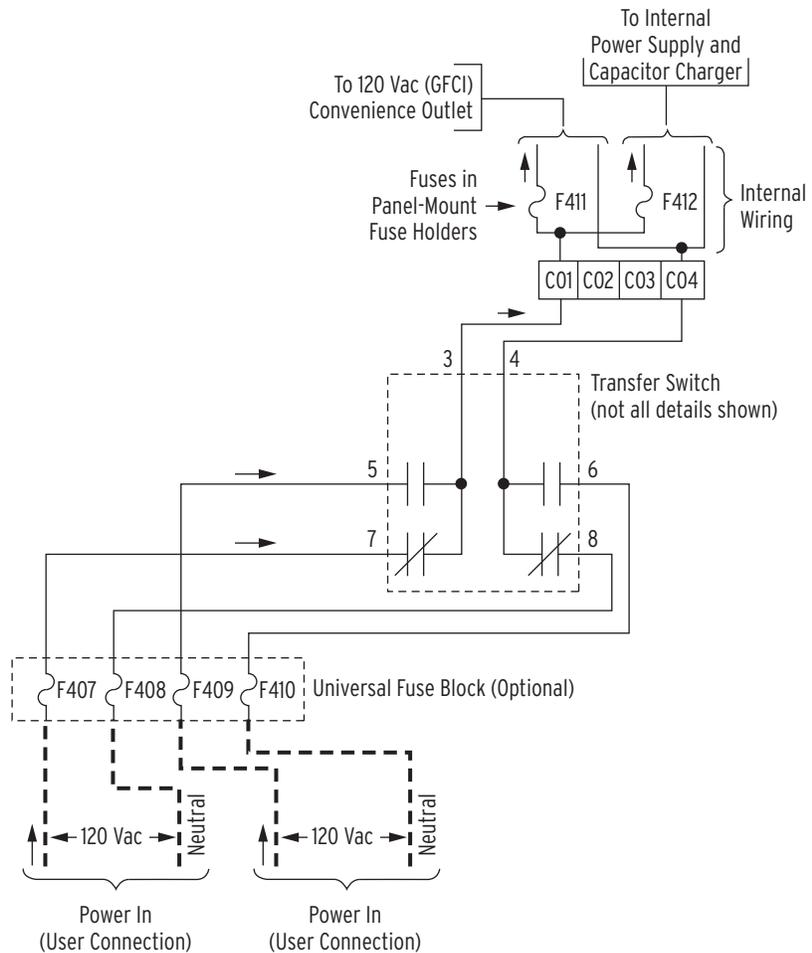
Figure 2.37   Universal Fuse Block/AC Transfer Switch Power Connections

Figure 2.38 provides the extra Transfer Switch connection and operational details, as compared to *Figure 2.36*. The Transfer Switch routes power either through Terminals 5/6 or Terminals 7/8. This routing is controlled by the dc coil shown in *Figure 2.38* (the dc coil is internal to the Transfer Switch and connected via Terminals 1 and 2).

➤ DC coil energized: Form A contacts corresponding to Terminals 5/6 **close** and Form B contacts corresponding to Terminals 7/8 **open** (power is routed through Terminals 5/6)

➤ DC coil de-energized: Form A contacts corresponding to Terminals 5/6 **open** and Form B contacts corresponding to Terminals 7/8 **close** (power is routed through Terminals 7/8)

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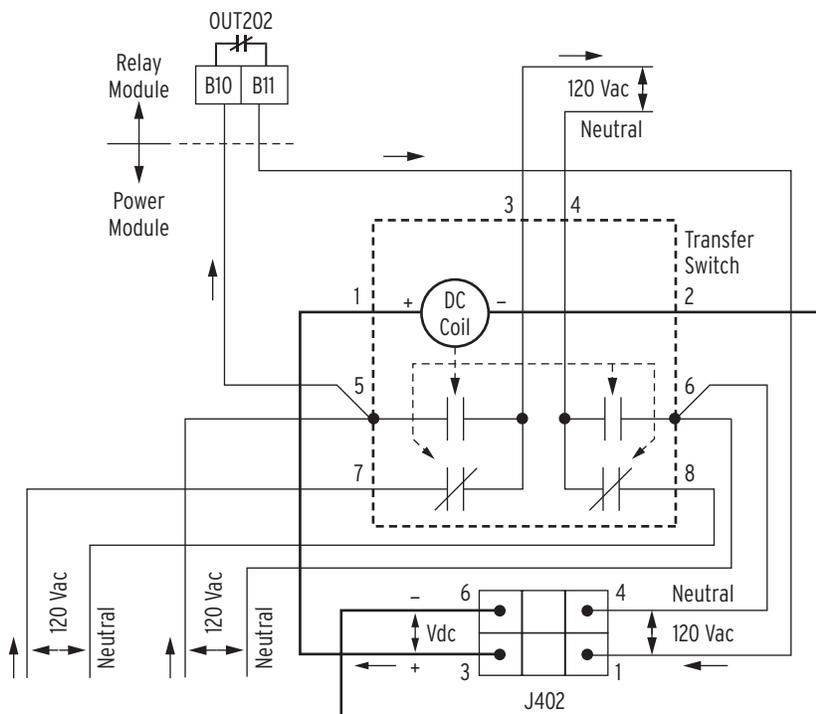
Figure 2.38 AC Transfer Switch AC/DC Voltage Connections

The energization or de-energization of the dc coil is dependent on the presence or absence, respectively, of the preferred 120 Vac power source. The preferred source is the 120 Vac power connected to Terminals 5/6 of the Transfer Switch.

An ac to dc voltage conversion is needed to convert the preferred 120 Vac power source signal to a dc voltage to energize the dc coil. The electronics behind connector J402 do this conversion. In *Figure 2.38*, note the 120 Vac input into connector J402 comes from Terminals 5/6 (preferred source) on the Transfer Switch. The Vdc output from connector J402 is then connected across the dc coil, via Transfer Switch Terminals 1/2. The effective voltage operation range (120 Vac base) of the dc coil of the transfer switch is the following:

➤ Pick Up Voltage: 104 ± 4 Vac

➤ Drop Out Voltage: 96 ± 4 Vac

➤ Minimum Hysteresis: 4 Vac (helps eliminate Transfer Switch chattering)

Note that the preferred 120 Vac power source signal is supervised by Form B output contact OUT202. If no special SELOGIC setting is made for output contact OUT202, then output contact OUT202 remains closed and has no effect on the operation of the Transfer Switch. The Transfer Switch operates based on the presence or absence of the preferred 120 Vac power source connected to Terminals 5/6 of the Transfer Switch. If a special SELOGIC setting is made for output contact OUT202, then output contact OUT202 can open under control of the SELOGIC setting and cause the Transfer Switch to switch from the preferred 120 Vac power source (Terminals 5/6) to the alternate 120 Vac power source (Terminals 7/8), for reasons other than the loss of the preferred source. See *Output Contacts on page 7.34* for more information on output contact OUT202.

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3-Pin Power Receptacle

To ease connection and removal of 120 Vac power, install the 3-pin power receptacle accessory (see *Figure 2.39*). A 3-pin power receptacle can be applied in *Figure 2.30* or *Figure 2.35*; and two 3-pin power receptacles can be applied in *Figure 2.36* or *Figure 2.37*, where 120 Vac, Power In (User Connection) is listed.
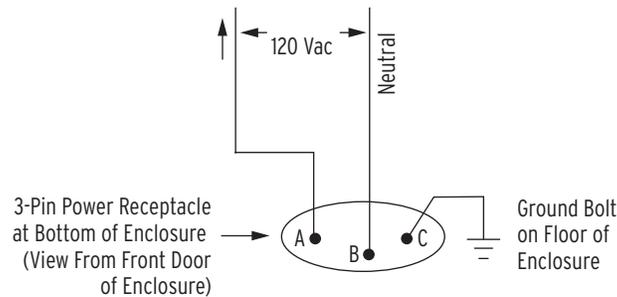
Figure 2.39   3-Pin Power Receptacle

This 3-pin power receptacle accessory is installed at the bottom of the enclosure (male pins to the outside), ready for receiving an outside cable (female sockets on cable). Such an outside cable then connects to a 120 Vac power source. Note in *Figure 2.39* that Pin C on the receptacle is connected to the hex head bolt (#10-32, stainless steel) that protrudes through the floor of the enclosure.

The key for the receptacle (to help in guiding outside cable connection) is oriented toward the rear door of the enclosure.

Low-Voltage Close Power (Traditional Retrofit Recloser Only)

Many Traditional Retrofit reclosers need 120 Vac power to close the main recloser contacts. Close operations for traditional reclosers are started with the 24 Vdc close circuit (see *Figure 2.50*), but the power required to close the main contacts and compress the tripping springs in the recloser is usually either 120 Vac, as discussed here, or primary voltage. This depends on recloser construction.

For convenience, such 120 Vac power can be brought out to the bottom of the enclosure from terminals C01 (120 Vac) and C04 (neutral) on the relay module (see *Figure 2.40*). This low-voltage close power accessory has a 2-socket receptacle at the bottom of the enclosure (female sockets to the outside), ready for receiving an outside 2-pin (male) cable connection. This outside cable (SEL-C515) then takes the 120 Vac power out to the recloser.

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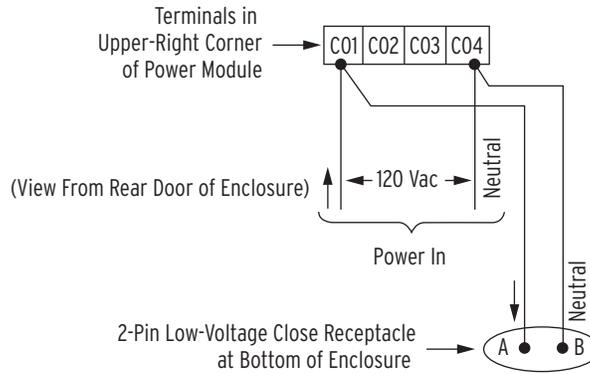
Figure 2.40 Low-Voltage Close Power Connections

The key for the receptacle (to help in guiding outside cable connection) is oriented toward the rear door of the enclosure.

Voltage Connections

In addition to traditional three-phase voltage connections, this subsection discusses:

➤ 8-pin receptacles for ease of connection and removal of power system secondary voltages

➤ Low-energy analog (LEA) voltage inputs connections

➤ Settings for designating phase connections

➤ Single-phase (line-neutral) and phase-to-phase voltage connections

Three-Phase Voltage Connections

Figure 2.41 shows two three-phase, Y-connected voltage circuits connected to the relay module voltage inputs (terminals Z09–Z16; voltage inputs rated as high as 300 Vac, line-neutral), via the Voltage Input Fuse Block. The Voltage Input Fuse Block can be installed as an accessory. The fuse blocks have integral fuse pullers, for ease of safely removing or installing fuses. Pull these fuses to simulate loss of voltage. Fuse values are given in *Table 2.3*.

If desired, the three-phase voltage circuits can be connected directly to the relay module voltage inputs (terminals Z09–Z16) in *Figure 2.41*, without going through the Voltage Input Fuse Block, although it is recommended that there be some kind of overcurrent protection on such voltage circuits. The three-phase voltage connections are used for Automatic Network Reconfiguration, under-/overvoltage elements, synchronism-check elements, power elements, metering, and so forth.

If the three-phase, Y-connected voltage circuits brought into the Voltage Input Fuse Block are capable of providing 120 Vac line-neutral power for the 120 Vac-powered unit, then additional wiring can be installed, as shown traversing to the right in *Figure 2.41*. This single-phase power is wired from the source side of the Voltage Input Fuse Block and available for connection to the power input circuitry portrayed in preceding *Figure 2.30*, *Figure 2.35*, *Figure 2.36*, and *Figure 2.37*. The power connections portrayed in *Figure 2.41* arbitrarily show line-neutral connections to the middle phases (i.e., V2Y-NY and V2Z-NZ).

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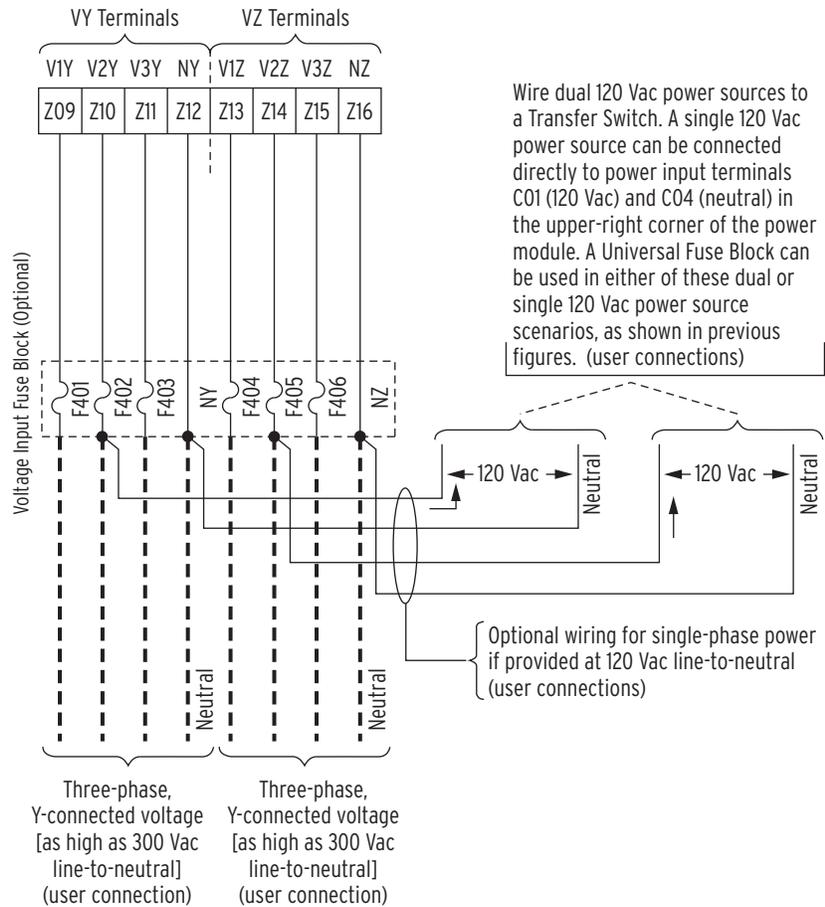
Figure 2.41   Three-Phase Voltage Connections for 300 Vac Voltage Inputs

For voltage input connections, the screws on terminals Z09–Z16 are #8-32. Use max. width 9.1 mm (0.36 in) ring terminals; tightening torque of 1.0 to 2.0 Nm (9 to 18 in-lb).

For Voltage Input Fuse Block connections (on older installations that use screws), the screws on fuse blocks F401–F406 are #10-32. Use max. width 11.4 mm (0.45 in) ring terminals; tightening torque of 1.0 to 2.0 Nm (9 to 18 in-lb).

For Voltage Input Fuse Blocks with wire insertion connections, strip the wire ends to 12 mm (0.47 in). Use 4 AWG to 16 AWG wire and a tightening torque of 2.5–3.0 Nm (23.0–27.0 in-lb). These newer fuse blocks also have wiring positions (unfused) NY and NZ for the respective voltage neutral connections (see *Figure 2.41*, *Figure 2.43*, and *Figure 2.45*).

8-Pin Receptacle for Voltage Connections

NOTE: In some cases when using low-energy analog (LEA) voltage input connections, not all connections are made.

For ease of connection and removal of power system secondary voltages, like those in *Figure 2.41*, install the 8-pin receptacle accessory for voltage inputs. *Figure 2.42* describes the 8-pin receptacle accessory. It is wired up directly to relay module voltage inputs Z09–Z16 or to the intermediate Voltage Input Fuse Block, if installed, as shown in *Figure 2.41*.

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8-Pin Voltage Receptacle
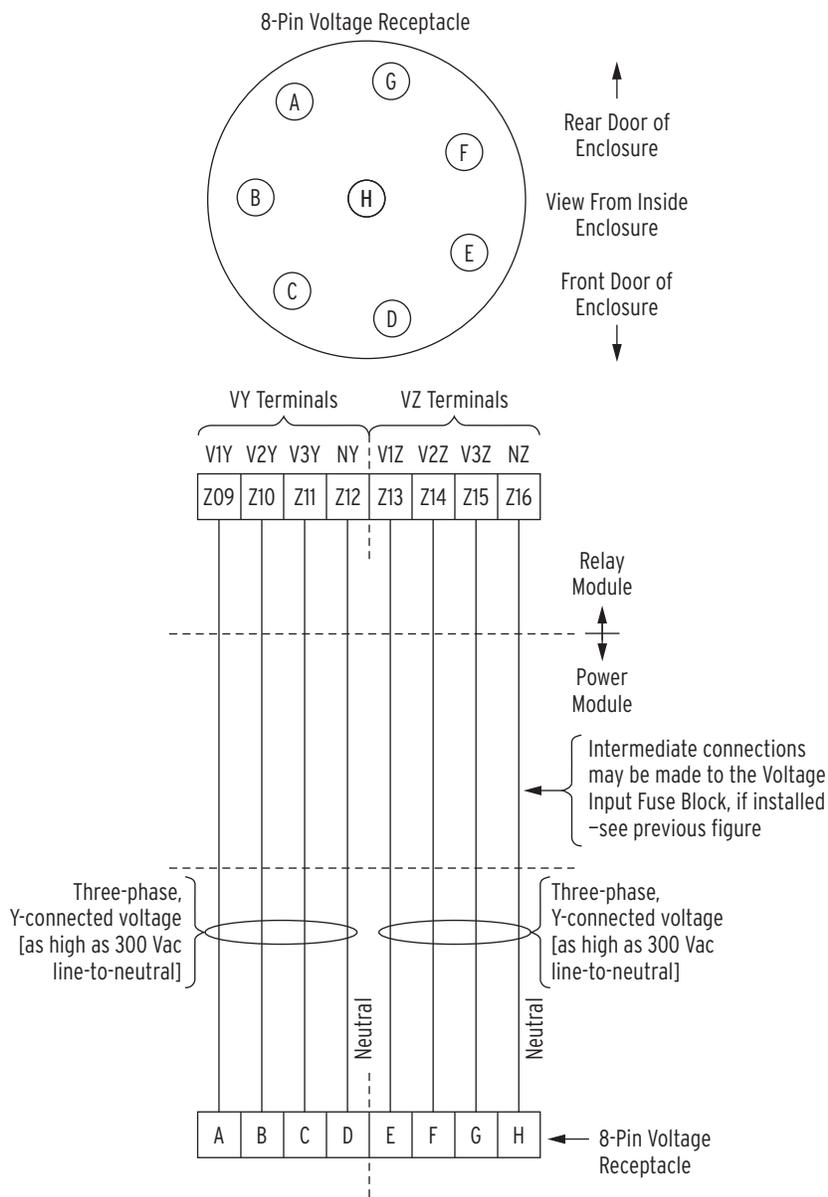
Figure 2.42   8-Pin Receptacles for Voltage Connections

This 8-pin receptacle at the bottom of the enclosure has male pins to the outside, ready for receiving an outside 8-socket (female) cable connection. Such an 8-socket cable then connects to the power system secondary voltages (e.g., three-phase, Y-connected voltages from both sides of the recloser).

The key for the receptacle (to help in guiding outside cable connection) is oriented toward the rear door of the enclosure.

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LEA (Low-Energy Analog) Voltage Inputs Connections
8 Vac LEA Inputs Voltage Connections

8 VAC LEA OPTIONS
There are more 8 VAC LEA input options than just those shown in Figure 2.43. See Figure 2.52 (GW Viper-ST, or G&W Viper-LT recloser), Figure 2.68 (Tavrida OSM AI_2 recloser), Figure 2.76, and Figure 2.77 (Multi-Recloser Interface). See the SEL-651R-2 Model Option Table.

FUSE BLOCK AND TERMINAL CONNECTION SPECIFICATIONS
See text following Figure 2.41.

SHIELDED CABLES
Shielded cables for LEA voltage inputs (not just 8 Vac LEA inputs) come preinstalled on some newer installations, with the shields effectively connected to ground at the bottom of the enclosure.

Figure 2.43   8 Vac LEA Voltage Connections for VY-Terminal Voltages
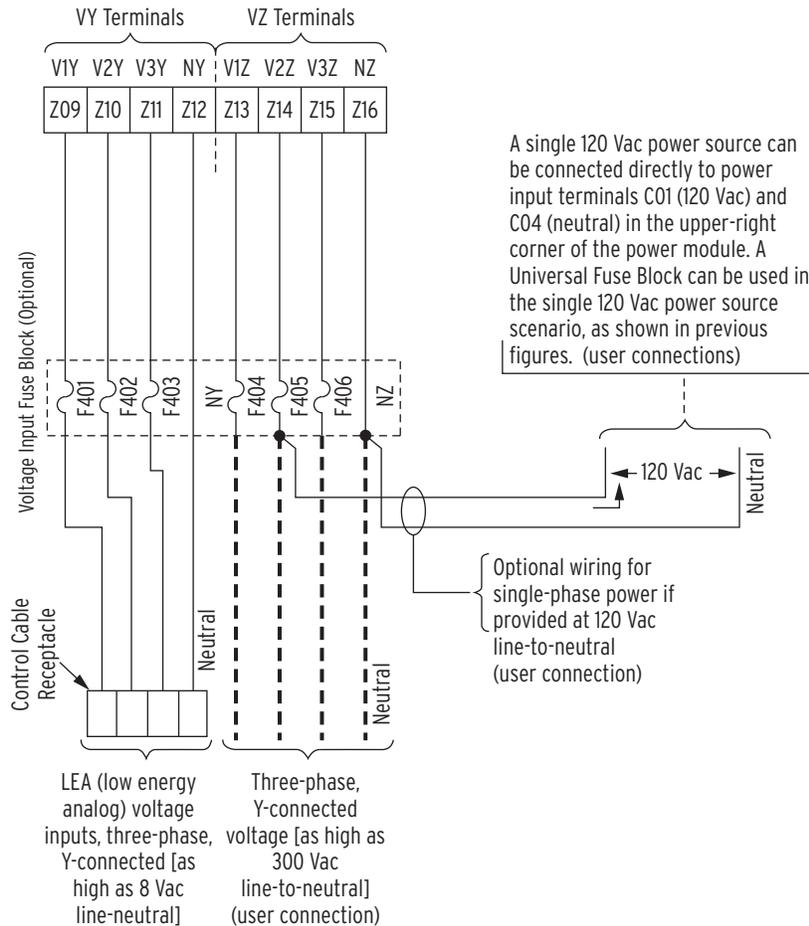
⚠️**CAUTION**
The recloser control must be mounted on the same pole as the recloser when LEA inputs are used. This practice reduces surges that may damage the recloser control. Shielded cables are recommended when using LEA inputs.

Figure 2.43 varies from *Figure 2.41* in that terminals Z09–Z12 (VY terminals) are rated as high as 8 Vac, line-to-neutral, instead of 300 Vac, line-to-neutral.

Figure 2.43 also varies from *Figure 2.45* and *Figure 2.46* in the voltage ratings of terminals Z13–Z16 (VZ terminals). The LEA ordering options for terminals Z09–Z12 accommodates the output of the three-phase capacitive screen voltage devices from one side of the G&W Viper-ST, G&W Viper-LT (see *Figure 2.52*), or Tavrida OSM AI_2 (see *Figure 2.68*), or Multi-Recloser Interface reclosers (see *Figure 2.76* and *Figure 2.77*).

Note the partial control cable shown at the bottom of *Figure 2.43*. These three-phase low-level voltage signals are brought from one side of the G&W Viper-ST or G&W Viper-LT recloser to the SEL-651R-2 in the standard control cable. The serial number label lists the phase voltage input ratings for the VY and VZ terminals.

These LEA voltage inputs can also be used with other low-level voltage signals, not exceeding 8 Vac. Such signals would be brought into the enclosure separately, such as through the 8-pin receptacle shown in *Figure 2.41*, not through any recloser control cable.

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Eaton NOVA LEA Inputs Voltage Connections

EATON NOVA-TS OR NOVA-STS VOLTAGE CONNECTIONS

The Eaton NOVA-TS or NOVA-STS Triple-Single recloser can use the control cable to bring voltage sensor outputs to the SEL-651R-2 (see Figure 2.65).
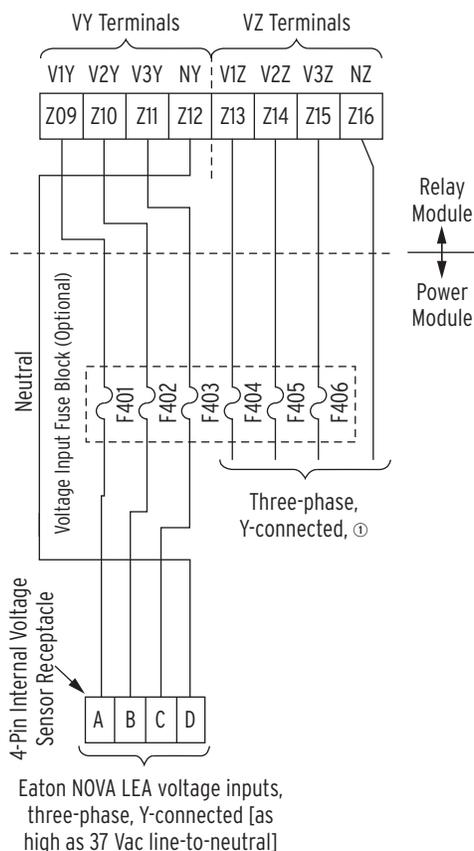
① Refer to Figure 2.43, or Figure 2.45, for VZ-terminal voltage connections.

Figure 2.44   Eaton NOVA LEA Voltage Connections for VY-Terminal Voltages (Control-Powered Eaton NOVA Recloser Example)

The Eaton NOVA LEA inputs ordering option for terminals Z09–Z12 accommodates the internal voltage sensing outputs of Eaton NOVA reclosers.

The 4-pin Internal Voltage sensor receptacle is shown at the bottom of *Figure 2.44*. These three-phase low-level voltage signals are brought from the NOVA recloser (equipped with Internal Voltage sensors) to the SEL-651R-2 through a shielded 4-conductor cable provided by Eaton. The serial number label lists the phase voltage input ratings for the VY and VZ terminals.

Refer to VZ-terminal voltage connections in *Figure 2.43*, if VZ-terminal voltage inputs are rated as high as 300 Vac. Refer to VZ-terminal voltage connections in *Figure 2.45*, if VZ-terminal voltage inputs are Lindsey SVMI LEA inputs. Refer to VZ-terminal voltage connections in *Figure 2.46* if VZ-terminal voltage inputs are Siemens SDR LEA inputs.

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Lindsey SVMI LEA Inputs Voltage Connections

LINDSEY SVMI LEA OPTIONS
There are more Lindsey SVMI input options than just those shown in Figure 2.45. See the SEL-651R-2 Model Option Table.

FUSE BLOCK AND TERMINAL CONNECTION SPECIFICATIONS
See text following Figure 2.41.
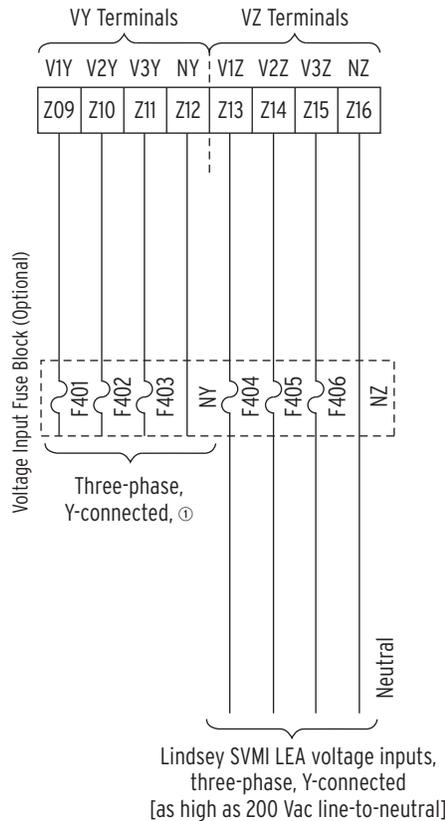
① Refer to Figure 2.41, Figure 2.43, or Figure 2.44, for VY-terminal voltage connections.

Figure 2.45   Lindsey SVMI LEA Voltage Connections for VZ-Terminal Voltages

Lindsey SVMI LEA inputs ordering option for terminals Z13–Z16 accommodates Lindsey's Standard Voltage Monitoring Insulators (SVMI) with AC output voltage of 120 Vac and the Load impedance greater than 1 MΩ.

These three-phase low-level voltage signals are brought from Lindsey SVMI to the SEL-651R-2 through a shielded 4-conductor cable. The serial number label lists the phase voltage input ratings for the VY and VZ terminals.

Refer to VY-terminal voltage connections in *Figure 2.41*, if VY-terminal voltage inputs are rated as high as 300 Vac. Refer to VY-terminal voltage connections in *Figure 2.43*, if VY-terminal voltage inputs are 8 Vac LEA inputs. Refer to VY-terminal voltage connections in *Figure 2.44*, if VY-terminal voltage inputs are Eaton NOVA LEA inputs.

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Siemens SDR LEA Inputs Voltage Connections
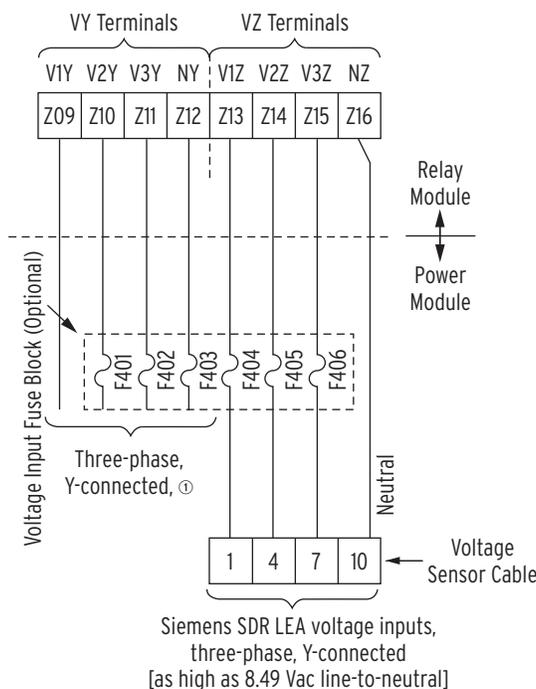
① Refer to Figure 2.41, Figure 2.43, or Figure 2.44, for VY-terminal voltage
connections.

**Figure 2.46   Siemens SDR LEA Voltage Connections for VZ-Terminal
Voltages**

Siemens SDR LEA inputs ordering option for terminals Z13–Z16
accommodates ac output voltage of 8.49 Vac.

These three-phase low-level voltage signals are brought from Siemens SDR to
the SEL-651R-2 through a shielded voltage sensor cable. The serial number
label lists the phase voltage input ratings for the VY and VZ terminals.

Refer to VY-terminal voltage connections in *Figure 2.41*, if VY-terminal
voltage inputs are rated as high as 300 Vac. Refer to VY-terminal voltage
connections in *Figure 2.43*, if VY-terminal voltage inputs are 8 Vac LEA
inputs. Refer to VY-terminal voltage connections in *Figure 2.44*, if
VY-terminal voltage inputs are Eaton NOVA LEA inputs. Refer to
VZ-terminal connections in *Figure 2.45* if VZ-terminal voltage inputs are
Lindsey SVMI LEA inputs.

Phase Designations for Voltage Connections

The voltage inscriptions for terminals Z09–Z16 in *Figure 2.5*, *Figure 2.9*,
Figure 2.41–Figure 2.46:

➤ V1Y, V2Y, V3Y, NY (VY-terminal connections)

➤ V1Z, V2Z, V3Z, NZ (VZ-terminal connections)

have no permanent A-, B- or C-phase designation. Phase designation is
determined by Global settings:

➤ VYCONN for VY-terminal connections

➤ VZCONN for VZ-terminal connections

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See *Current and Voltage Connections (Global Settings) on page 9.28* for more information on these settings.

Single-Phase and Phase-to-Phase Voltage Connections

Any single-phase or phase-to-phase voltage connections are made between terminals V1Y-NY and V1Z-NZ for the VY and VZ sides, respectively. See *Current and Voltage Connections (Global Settings) on page 9.28* for information on how previously referenced Global settings VYCONN and VZCONN also handle single-phase or phase-to-phase voltage connections.

Additional Relay Connections

Connect extra I/O, IRIG-B time code, EIA-232 serial ports, and auxiliary 12 Vdc power as needed in the application.

Extra Inputs/Outputs

Optoisolated inputs IN101–IN107 and output contacts OUT101–OUT108 are an ordering option and available for connection at the top of the relay module rear panel, row 100. Output contacts OUT201 and OUT202 are standard and available for connection in the middle of the relay module rear panel, row 200. In *Figure 2.5* and *Figure 2.9* notice that the output contact types are:

➤ Form A (normally open): OUT101–OUT105

➤ Form C (normally closed/normally open): OUT106–OUT108, OUT201, OUT202

Notice that the Form C output contacts share a common terminal and that optoisolated inputs IN106 and IN107 also share a common terminal. Ratings for the optoisolated inputs and output contacts are found in *Specifications on page 1.9*. The serial number label lists the optoisolated input voltage rating (listed under label: **CONTACT INPUTS**).

For optoisolated inputs IN101–IN107 and output contacts OUT101–OUT108 connections, the screws on terminals A01–A32 are #8-32. Use max. width 9.1 mm (0.36 in) ring terminals; tightening torque of 1.0 to 2.0 Nm (9 to 18 in-lb).

The screw terminal connectors for optoisolated inputs IN101–IN107 and output contacts OUT101–OUT108 can be removed by unscrewing the screws at each end of the connector block.

Step 1. Remove the connector by pulling the connector block straight out.

Note that the receptacle on the relay circuit board is keyed; you can insert each screw terminal connector in only one location on the rear panel.

Step 2. To replace the screw terminal connector proceed with the following steps:

a. Confirm that you have the correct connector.

b. Push the connector firmly onto the circuit board receptacle.

c. Reattach the two screws at each end of the block.

This feature allows the terminal wiring to remain undisturbed.

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Additionally, you can rotate these screw terminal connectors so that the connector wire dress position is the reverse of the factory-installed position, for example, wires entering the relay panel from below instead of from above. To rotate these connectors, you must change the screw terminal connector keying. Inserts in the circuit board receptacles key the receptacles for only one screw terminal connector in one orientation. Each screw terminal connector has a missing web into which the key fits (see *Figure 2.47*). If you want to reverse the connector orientation, you must rearrange the receptacle keys to match the screw terminal connector block. Use long-nosed pliers to move the keys.
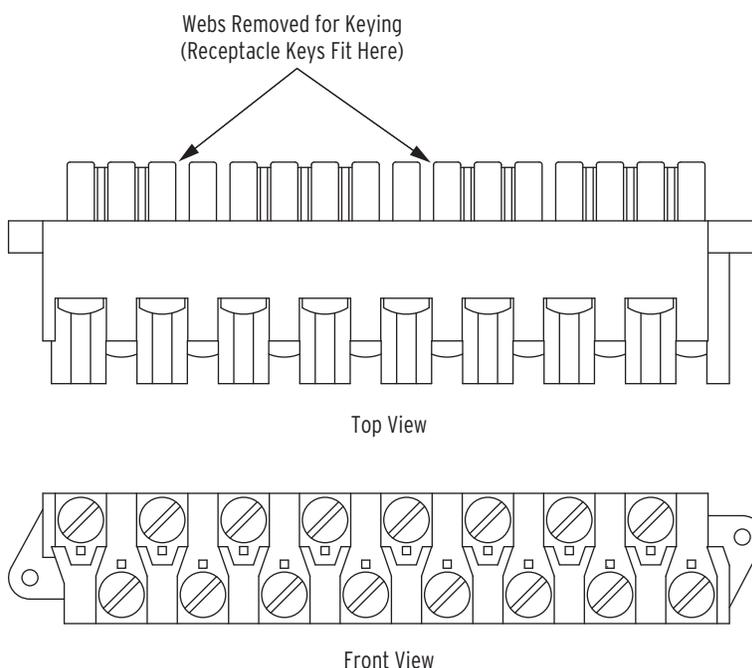
Figure 2.47   Screw Terminal Connector Keying

Standard Outputs

For output contacts OUT201–OUT202 connections, the screws on terminals B07–B12 are #6-32. Use max. width 7.9 mm (0.31 in) ring terminals; tightening torque of 0.9 to 1.3 Nm (8 to 12 in-lb).

Alarm Output

From the factory, OUT201 is configured as an alarm. OUT202 is wired into the Transfer Switch scheme, when installed at the factory (see *Figure 2.38*).

IRIG-B Time-Code Input

The SEL-651R-2 accepts a demodulated IRIG-B time signal to synchronize the recloser control internal clock with an external source. The demodulated IRIG-B time signal can come from an SEL Communications Processor, the SEL-2100 Logic Processor, or from a satellite-synchronized clock such as the SEL-2407, SEL-2404, or SEL-2401. The IRIG-B time signal can be input to the rear-panel BNC connector labeled IRIG or to Port 2.

A demodulated IRIG-B time code can be input into serial Port 2 by using an SEL-C273A cable to connect serial Port 2 of the SEL-651R-2 to an SEL Communications Processor.

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Connect the rear-panel BNC connector directly to a high-accuracy satellite synchronized clock such as the SEL-2407 or SEL-2401 to synchronize the relay internal clock within one microsecond, and enable high-accuracy synchrophasors. See *Appendix J: Synchrophasors* for more information on enabling and using synchrophasors in the SEL-651R-2.

If a time code is input to serial Port 2 and the BNC IRIG connector, the recloser control synchronizes to the time code received on the BNC connector.

Serial Ports

All EIA-232 ports accept 9-pin D-subminiature male connectors. Port 2 includes the IRIG-B time-code signal input.

The pin definitions for all the ports are given on the relay rear panel and detailed in *Table 10.3–Table 10.5*.

Refer to *Section 10: Communications* for detailed cable diagrams for selected cables (cable diagrams follow *Table 10.5*).

+12 Vdc Auxiliary Power Supply

A +12 Vdc auxiliary power supply rated for 40 W continuous and surges to 60 W is a standard feature in ac powered units. DC-powered units are rated at a lower level (see *Specifications on page 1.9* for ratings). Use this supply to power radios, small RTUs, or other accessories installed in the cabinet. Three +12 Vdc and three return terminal screws are provided for convenience. Fuse F202 protects this +12 Vdc supply (fuse F202 is in-line with the +12 Vdc rail; see *Table 2.3*).

For +12 Vdc and Return connections, the screws on terminals B01–B06 are #6-32. Use max. width 7.9 mm (0.31 in) ring terminals; tightening torque of 0.9 to 1.3 Nm (8 to 12 in-lb).

Relay Module Main Board Jumpers and Clock Battery

The main board (top circuit board) in the SEL-651R-2 relay module has features that very infrequently (if at all) need to be set or changed. These features are:

➤ Access and Breaker Control jumpers

➤ Serial port voltage jumpers

➤ Clock battery

Gain access to the Access and Breaker Control jumpers by removing the front panel. Access the serial port voltage jumpers by removing the plastic cover over the opening labeled **JMP 2 3** on the relay module (near **Serial Port 3**). Access the clock battery by removing the front panel and then sliding out the main board. The procedures for doing so follow later in this subsection.

Access and Breaker Control Jumpers

The Access and Breaker Control jumpers are jumpers JMP2-A and JMP2-B, respectively, found at the front of the main board (see *Figure 2.48*). In this figure, notice that these jumpers are lettered left to right (D C B A).

Figure 2.48 shows the location, function, and factory-default configuration for the Access and Breaker Control jumpers.

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When the Access jumper is installed, passwords are disabled, and connection to any enabled communications port is allowed full access to inspect/change/reset all reports, settings, etc., to upgrade firmware and to control the circuit breaker (if the Breaker Control jumper is installed as described below) without password authentication.

The Access jumper also affects the relay behavior for settings EPORT and MAXACC at startup as follows:

➤ For the front-panel serial port (Port F) and the USB port, the Access jumper overrides the port enable setting EPORT = N, and enables the port(s) with EIA-232 Port F default settings for PROTO, SPEED, BITS, PARITY, STOP, and RTSCTS. If the Port F setting EPORT was already set to Y, the front port(s) remain enabled, and the EIA-232 Port F uses its previous settings.

➤ For the front-panel serial port (Port F) and the USB port, the Access jumper overrides the Port F MAXACC setting and allows access to security levels 1, B, 2, or C without a password.

➤ For Serial Ports 1, 2, or 3, and Ethernet Port 5 (except FTP and HTTP), if that port has setting EPORT = Y, the Access jumper overrides the MAXACC setting of that port and allows access to security levels 1, B, 2, or C without a password.

➤ For Serial Ports 1, 2, or 3, and Ethernet Port 5, if that port has setting EPORT = N, the Access jumper has no effect and the port remains disabled.

If passwords are forgotten, put jumper JMP2-A temporarily in place (ON) to gain access to the relay and retrieve the password settings, via the **PASSWORD** command.

Use the Breaker Control jumper to enable or disable breaker control **OPEN**, **CLOSE**, and **PULSE** commands through the SEL ASCII protocol and breaker operations through the SEL Fast Operate protocol (DNP3, Modbus, IEC 61850) and the front-panel menu-driven user interface. Note that the Breaker Control jumper does *not* supervise operation of Local Bits, Remote Bits, or the **Trip**/**Close** pushbuttons shown in *Figure 2.4* and *Figure 2.8*.

In *Figure 2.48*, note there are two additional jumper positions, JMP2-C and JMP2-D. These two jumpers are not used and the positions (ON or OFF) of these jumpers are of no consequence.

Serial Port Voltage Jumpers

The jumpers listed in *Table 2.1* connect or disconnect +5 Vdc to Pin 1 on the corresponding EIA-232 serial ports. The +5 Vdc is rated at 0.5 A maximum for each port. See *Table 10.3* for all EIA-232 serial port pin functions.

⚠ **CAUTION**
Do not access/move jumpers while the unit is powered up.

The jumpers are accessible from the opening labeled **JMP 2 3** on the relay module (near Serial **Port 3**; see *Figure 2.5* and *Figure 2.9*). The jumper under label **2** (JMP1-P2) corresponds to Serial Port 2 and the jumper under label **3** (JMP1-P3) corresponds to Serial Port 3.

The +5 Vdc is **not** connected to Pin 1 on the corresponding EIA-232 serial ports when the jumpers are OFF (removed/**not** in place over both pins). Put the jumpers ON (in place over both pins) so that the +5 Vdc is connected to Pin 1 on the corresponding EIA-232 serial ports, if needed. This Pin 1 power source is useful for powering some types of external modems.

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Table 2.1   Serial Port Voltage Jumper Positions

+5 VDC to Pin 1	Serial Port 2	Serial Port 3
Disconnected	JMP1-P2 = OFF	JMP1-P3 = OFF
Connected	JMP1-P2 = ON	JMP1-P3 = ON

Condition of Acceptability for North American Product Safety Compliance

To meet product safety compliance for end-use applications in North America, use an external fused rated 3 A or less in-line with the +5 Vdc source on Pin 1. SEL fiber-optic transceivers include a fuse that meets this requirement.

Clock Battery

Refer to *Figure 2.48* for clock battery location (front of main board). A lithium battery powers the relay clock (date and time) if the external power source (ac power or 12 V battery) is lost or removed. The clock battery is a 3 V lithium coin cell. At room temperature (25ºC), the clock battery will nominally operate for 10 years at rated load.

If power is lost or disconnected, the clock battery powers the clock. When the relay is powered normally from an external source, the clock battery experiences a low self-discharge rate. Thus, clock battery life can extend well beyond the nominal 10 years because it rarely has to discharge after the relay is installed. The clock battery cannot be recharged.

If the relay does not maintain the date and time after power loss, replace the clock battery. Follow the main board removal instructions that follow.

Accessing the Relay Module Main Board in the Dual-Door Enclosure

Refer to *Figure 2.48*.

⚠**DANGER**

Disconnect or de-energize all external connections before opening this device. Contact with hazardous voltages and currents inside this device can cause electrical shock resulting in injury or death.

⚠**DANGER**

The removed cables for connections **J201, J202,** and **J205** are still energized. Contact with such terminals can cause electrical shock that can result in injury or death.

⚠**CAUTION**

Equipment components are sensitive to electrostatic discharge (ESD). Undetectable permanent damage can result if you do not use proper ESD procedures. Ground yourself, your work surface, and this equipment before removing any cover from this equipment. If your facility is not equipped to work with these components, contact SEL about returning this device and related SEL equipment for service.

Step 1.   Following your company's standard procedure, remove the SEL-651R-2 from service.

Step 2.   Make sure the unit remains grounded.

Step 3.   Remove any cables connected to serial ports on the front and rear panels.

Step 4.   Remove the IRIG-B cable, too.

Step 5.   De-energize the relay module by disconnecting the following cables from the rear panel in the following order (see *Figure 2.5* and *Figure 2.29*).

    a.   **CAPACITORS (J205)**

    b.   **BATTERY (J202)**

    c.   **DC POWER IN (J201)**

Step 6.   Loosen the four front-panel screws (they remain attached to the front panel).

Step 7.   Remove the relay module front panel (see *Figure 2.4*), disconnecting the large ribbon cable connected to it by operating the cable ejector latches on the front-panel circuit board.

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Step 8. Place the front panel in an ESD (Electrostatic Discharge)-safe place to prevent ESD damage.

At this point, you can access the Access and Breaker Control jumpers (JMP2-A and JMP2-B, respectively) and the clock battery (see *Figure 2.48*), if need be.

Step 9. If changing the Access and Breaker Control jumpers, carefully remove and insert them in the desired configuration (ON or OFF).

Step 10. If changing the clock battery, carefully remove the old battery. If necessary, use a small tool to lever the battery up so that it can be extracted from the clip that holds it down.

Step 11. With the positive side (+) of the new battery face up, insert the battery at an angle to get it under the clip and then slide it into position.

Step 12. Later, set the relay date and time via the serial communications port or front panel.

Step 13. Reconnect the ribbon cable removed in *Step 7*.

Step 14. Replace the relay front-panel cover.

Step 15. Re-energize the relay module by reconnecting the following cables in the following order:

   a. **DC POWER IN (J201)**

   b. **BATTERY (J202)**

   c. **CAPACITORS (J205)**

Step 16. Replace any external cables previously connected to serial ports and IRIG-B port.

Step 17. Following your company's standard procedure, put the SEL-651R-2 back in service.

Accessing the Relay Module Main Board in the Single-Door Enclosure

Step 1. Following your company's standard procedure, remove the SEL-651R-2 from service.

Step 2. Make sure the unit remains grounded.

Step 3. Remove the swing panel that covers the relay module wiring.

Step 4. Remove the left mounting bracket and the smaller right mounting bracket (containing the 120 Vac convenience outlet), and set them in an "out-of-the-way" position on the floor of the enclosure.

Step 5. Remove any cables connected to the serial ports on the front and rear panels.

Step 6. Remove the IRIG-B cable.

Step 7. De-energize the relay module by disconnecting the following cables from the rear panel in the following order (see *Figure 2.9* and *Figure 2.29*).

   a. **CAPACITORS (J205)**

   b. **BATTERY (J202)**

   c. **DC POWER IN (J201)**

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Step 8.   Remove other individual connections to the power module (e.g., voltage and current connections), labeling them before removal so they can be reconnected correctly.

Step 9.   Remove the bottom and top row of nuts that fasten the respective bottom and top mounting plates (holding together the combined relay module/power module unit) to the enclosure. When these nuts are removed, the unit will still rest on the corresponding permanent mounting studs. Use caution to make sure the combined relay module/power module unit does not slide off the permanent mounting studs while the corresponding nuts are being removed.

Step 10.   With two people, lift the combined relay module/power module unit up and off the permanent mounting studs and out of the enclosure.

Step 11.   Take the combined relay module/power module unit to an ESD-safe area and follow standard ESD procedures in the following disassembly/reassembly procedure.

Step 12.   Remove the screws that hold the plate covering the back side of the relay module. Remove the plate and set aside.

At this point, you can access the Access and Breaker Control jumpers (JMP2-A and JMP2-B, respectively) and the clock battery (see *Figure 2.48*), if need be.

Step 13.   If changing the Access and Breaker Control jumpers, carefully remove and insert them in the desired configuration (ON or OFF).

Step 14.   If changing the clock battery, carefully remove the old battery. If necessary, use a small tool to lever the battery up so that it can be extracted from the clip that holds it down.

Step 15.   With the positive side (+) of the battery face up, insert the battery at an angle to get it under the clip and then slide it into position.

Step 16.   Later, set the relay time and date via the serial communications port or front panel.

Step 17.   Replace the plate that covers the back side of the relay module.

Step 18.   With two people, lift the combined relay module/power module down into the cabinet and onto the permanent mounting studs.

Step 19.   Replace the nuts that fasten the top and bottom mounting plates of the combined relay module/power module unit to the permanent mounting studs in the enclosure.

Step 20.   Reconnect all of the connections removed in *Step 5–Step 8*.

Step 21.   Replace the left and right mounting brackets removed in *Step 4*.

Step 22.   Replace the swing panel.

Step 23.   Following your company's standard procedure, put the SEL-651R-2 back in service.

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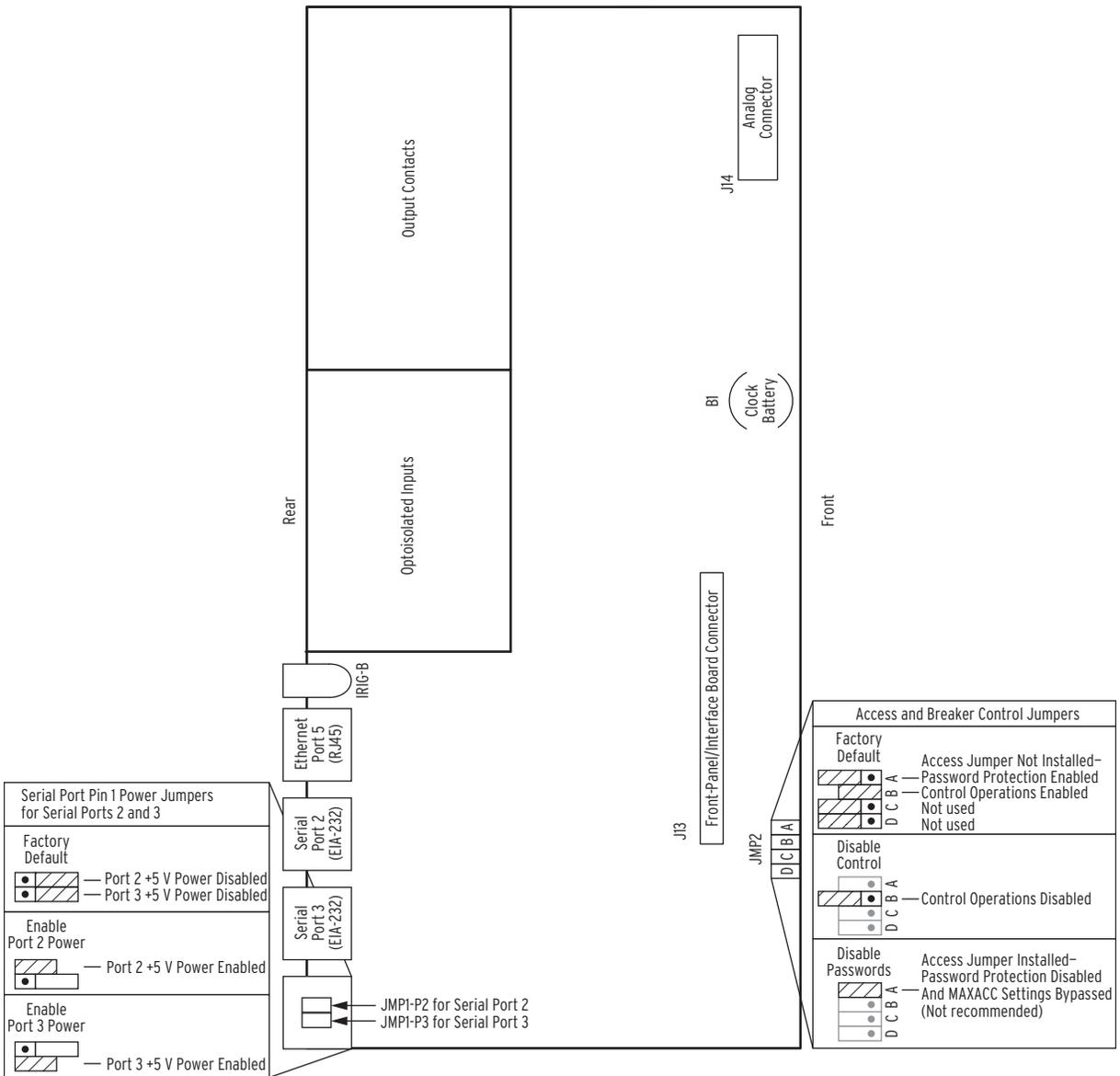
Figure 2.48   Jumper, Connector, and Major Component Locations on the Main Board

Battery and Fuse Replacement

The SEL-651R-2 is shipped with either a 16 or 40 Ah extended temperature battery. Either of these battery types may be used as a replacement for the installed battery. The part numbers and characteristics are listed in *Table 2.2*. Full specifications are shown in *Battery Specifications on page 1.11*. Connections are shown in *Figure 2.29*. After replacing a failed battery, the **STA C** command should be issued to clear the failed battery condition (see *Section 10: Communications*). Perform a **BTT NOW** command to verify the condition of the replacement battery (see *Battery System Monitor on page 8.39* for help on testing the battery).

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Table 2.2   Replacement Batteries for the SEL-651R-2

Function	Option 1	Option 2
Part Number	Enersys Genesis XE16X	Enersys Genesis XE40X
Capacity	16 Ah	40 Ah
Battery Life	≥4 years @ +25°C ≥1 year @ +80°C	≥4 years @ +25°C ≥1 year @ +80°C
Weight	6.4 kg (≤14.1 lb)	16.1 kg (≤35.4 lb)

See *Figure 2.5* and *Figure 2.9* for fuse positions **F201**–**F203** on the rear panel of the relay module. See *Figure 2.3* for fuse positions **F401**–**F412** on the rear panel of the power module. Fuses **F407** and **F408** (for a 230 Vac unit) are not shown in *Figure 2.3*, but the fuse blocks for these fuses are mounted in the same general area as the F411 and F412 panel-mounted fuse holders in *Figure 2.3*.

Table 2.3   Replacement Fuses for the SEL-651R-2

Fuse Name/Figure Reference	Ampere Rating	Dimensions	Manufacturer	Catalog Numbers	Purpose
F201/relay module (*Figure 2.29*)	30 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Littelfuse	314 030	Protect battery or battery charger circuitry from inadvertent short.
F202/relay module (AC power supply models only)	5 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Littelfuse	314 005	Protect 12 Vdc aux power supply.
F202/relay module (DC power supply models only)	0.5 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Bussman	MDL-1/2-R	Protect 12 Vdc aux power supply on models with DC power supplies.
F203/relay module (Traditional Retrofit, Control-Powered Eaton NOVA, G&W Control Power Viper-S, and Eaton NOVA-TS or NOVA-STS Triple-Single reclosers only; *Figure 2.50*, *Figure 2.60*, and *Figure 2.66*)	7 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Littelfuse	313 007	Protect from inadvertent +24 Vdc (or +53 Vdc) short when connecting control cable.
F401–F406/power module (*Figure 2.41* and *Figure 2.46*)	1 A	10.3 x 38.1 mm (0.41 x 1.5 in)	Eaton	KTK-1	Installed in Voltage Input Fuse Block accessory. Protect both three-phase voltage inputs on the relay module.
F407–F410/power module (*Figure 2.35* and *Figure 2.37*)	30 A	10.3 x 38.1 mm (0.41 x 1.5 in)	Littelfuse	FLQ 30	Installed in Universal Fuse Block accessory. Protect transfer switch and other 120 Vac power accessories on the power module.
F411/power module (120 Vac power supply only; *Figure 2.30*)	15 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Littelfuse	314 015	Protect 120 Vac (GFCI) convenience outlet from overload or line-to-line short circuits (15 Amp load limit).
F412/power module (120 Vac or 125 Vdc power supply only; *Figure 2.30* and *Figure 2.32*)	10 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Littelfuse	314 010	Protect 120 Vac or 125 Vdc power modules from overvoltage or internal short.
F412/power module (48 Vdc power supply only; *Figure 2.33*)	20 A	6.35 x 31.75 mm (0.25 x 1.25 in)	Littelfuse	314 020	Protect 48 Vdc power module from overvoltage or internal short.
F407 and F408/power module (230 Vac power supply only; *Figure 2.31*)	8 A	10.3 x 38.1 mm (0.41 x 1.5 in)	Littelfuse	FLQ 8	Protect 230 Vac power module from overvoltage or internal short.

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Traditional Retrofit Reclosers

Figure 2.49 shows the SEL-651R-2 factory wiring for current connections for Traditional Retrofit reclosers. Notice that the current transformers in the recloser are wired such that the residual path (through Pin K) is on the polarity side of the current transformer secondaries. This is nonstandard as far as traditional circuit breakers are concerned, but is easily accommodated by the wiring on the Z01–Z08 terminals of the relay module of the SEL-651R-2.
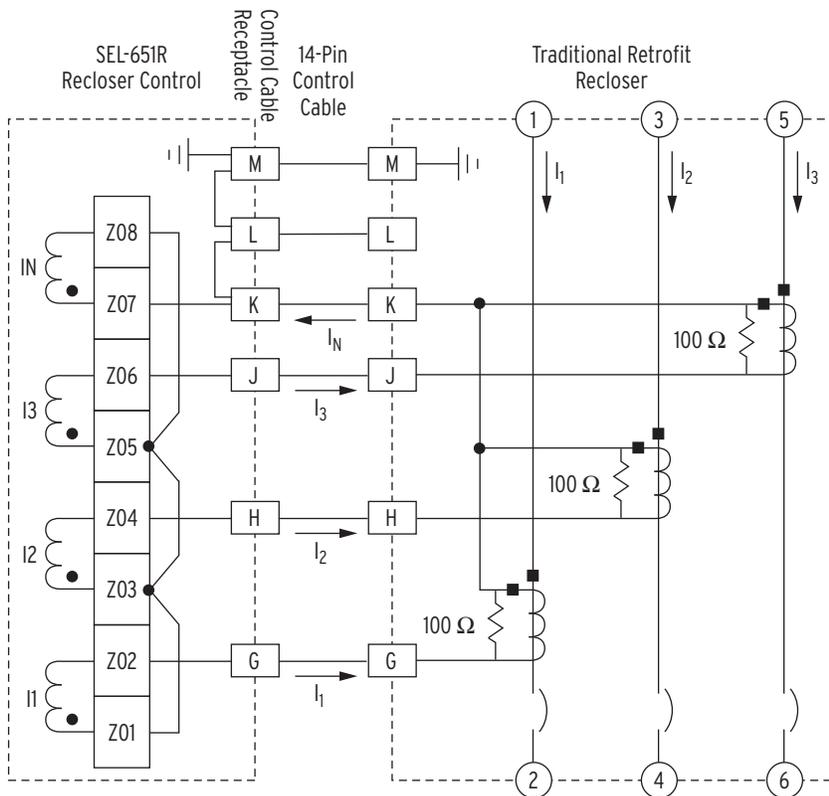
Figure 2.49 Current Connections and Polarity From Traditional Retrofit Recloser Primary to SEL-651R-2 Recloser Control Current Inputs

Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow, and so forth.

Figure 2.50 shows the SEL-651R-2 factory wiring for trip/close/recloser status for traditional reclosers; 24 Vdc power goes out Pin A to the recloser and then returns through the trip circuit and close circuit paths.

The trip circuit path (top to bottom) is described below:

Trip coil—SW1 (52a)—trip FET (controlled by Relay Word bit RCTR1X; see *Figure 7.25*)

Pins B, D are monitored by input IN203 and Pin C is monitored by input IN204. The 52a recloser status is derived from these inputs.

INTERNAL BATTERY-CHARGING TRANSFORMER
Some Eaton reclosers have an internal battery-charging transformer (current transformer). This charging transformer is not used by the SEL-651R-2: its 12 Vdc battery is charged from a user-supplied Vac power source. If one of these reclosers is connected to the SEL-651R-2, this charging transformer is electrically shorted at the control cable receptacle (Pins K and L are shorted together and grounded—see Figure 2.49).

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RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 24 Vdc voltage in Figure 2.50 is present for recloser operations (TCCAP = logical 1). The 24 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8). Relay Word bit TCCAP does not detect an operation of fuse F203 in Figure 2.50.

The close circuit path (top to bottom) is described below:

SW3 (52b)—SW2 (69)—close coil—close FET (controlled by Relay Word bit RCCL1X; see *Figure 7.25*)

Pin E is monitored by input IN202 and Pin F is monitored by input IN201. Contact SW2 (69) opens and stays open when the external yellow operating handle on the recloser is pulled to the lock-open position. With contact SW2 open, there is no way to close the recloser until the yellow operating lever is reset again. Contact SW2 is then closed.

① See Figure 7.25
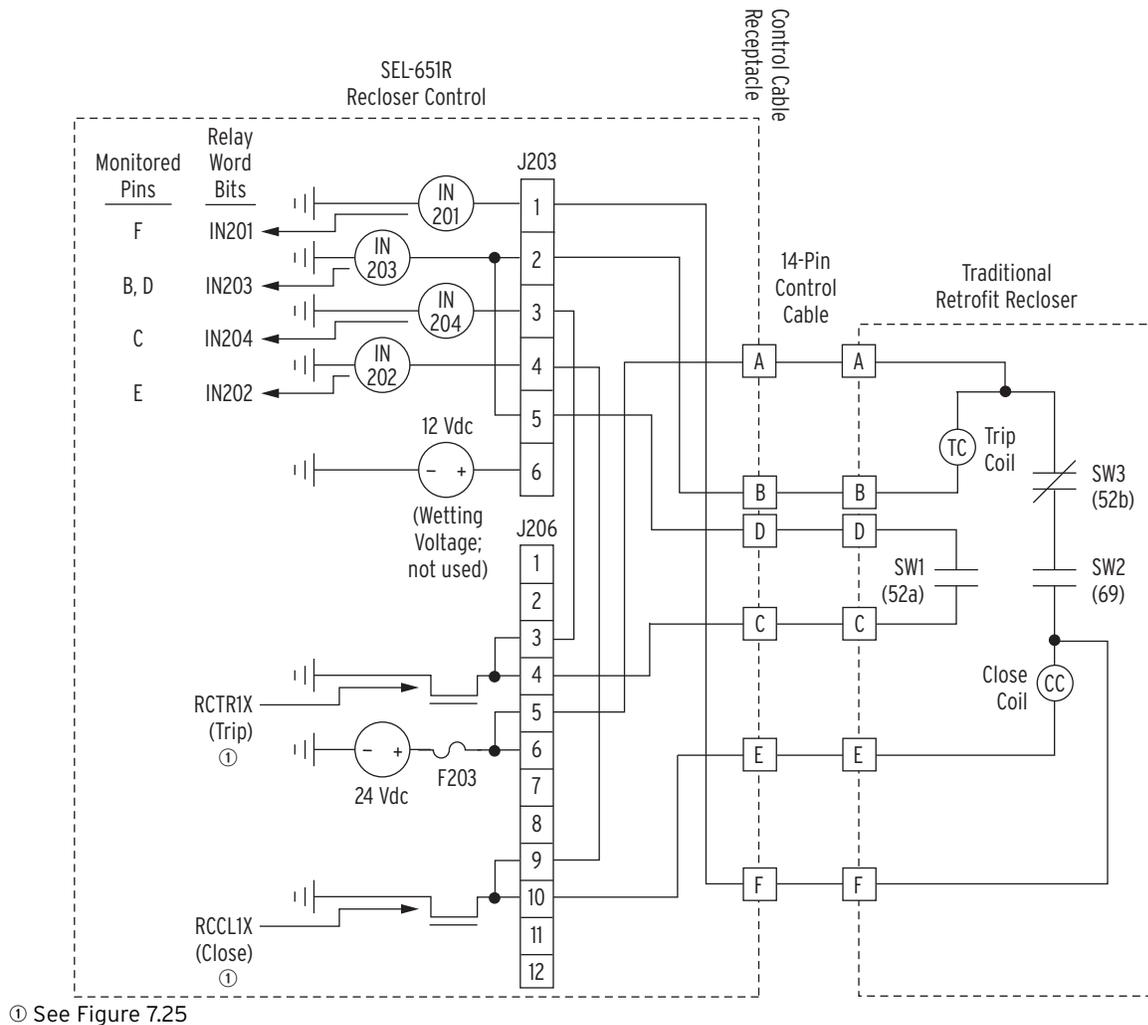
Figure 2.50   Trip/Close and Recloser Status Circuit Connections Between Traditional Retrofit Recloser and SEL-651R-2 Recloser Control

Motor-Operated Traditional Retrofit Reclosers

With factory settings, the SEL-651R-2 Recloser Control (ordered for a Traditional Retrofit recloser) also works with motor-operated reclosers, such as Eaton MVE, CVE, CXE, CZE, VSA, and VSO reclosers. Figure 2 in SEL Application Guide AG99-10, *Change Logic in SEL-351R Recloser Control for*

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Motor-Operated Reclosers, shows the internal differences for such reclosers, especially 52a at the top of trip circuit and diode bypassing SW1(52a). The SEL-651R-2 factory settings important for working with these motor-operated reclosers are Group settings:

TDURD := **40 cycles** (longer trip duration)

ULTR3P := **1** (set directly to logical 1; not dependent on NOT 52A3P to unlatch trip)

The **RECLOSER OPEN** LED is set as follows:

PB12_LED := **NOT(52A3P)**

For a regular Traditional Retrofit recloser, as shown in *Figure 2.50*, as opposed to a motor-operated recloser (see *Figure 2* in the aforementioned SEL Application Guide AG99-10) this setting can be changed to:

PB12_LED := **NOT(52A3P) AND IN203**

Input IN203 monitors Pins B/D, as shown in *Figure 2.50*. With this setting change, the **RECLOSER OPEN** LED will extinguish when the control cable is removed from the SEL-651R-2 Recloser Control.

If the recloser is *not* a motor-operated recloser, setting TDURD can be changed, if desired. See *Minimum Trip Duration Timer on page 5.7* for more detail.

Inputs Connector J204/G&W 14-Pin Viper Recloser

INPUTS connector **J204** on the rear panel of the SEL-651R-2 relay module is for extra signaling back from the G&W Viper recloser, a Traditional Retrofit type recloser. *Figure 2.51* shows wetting voltage (24 Vdc) coming from connector **J204** Pin 1, routing through signaling contacts on the G&W Viper, and back to inputs IN205 and IN206 on connector **J204**.

The Form A contact connected to input IN205 indicates low SF6 gas pressure inside the G&W Viper recloser. The Form B contact connected to input IN206 indicates loss of 120 Vac low voltage close power at the G&W Viper recloser. Pin 3 on connector **J204** can be used as a ground return for a separate optoisolated input (e.g., IN101) wetted by the 24 Vdc on Pin 1.

NOTE: For the application in Figure 2.51, the wiring/cabling between the INPUTS connector **J204** on the SEL-651R-2 and the G&W Viper Recloser is not provided by SEL.
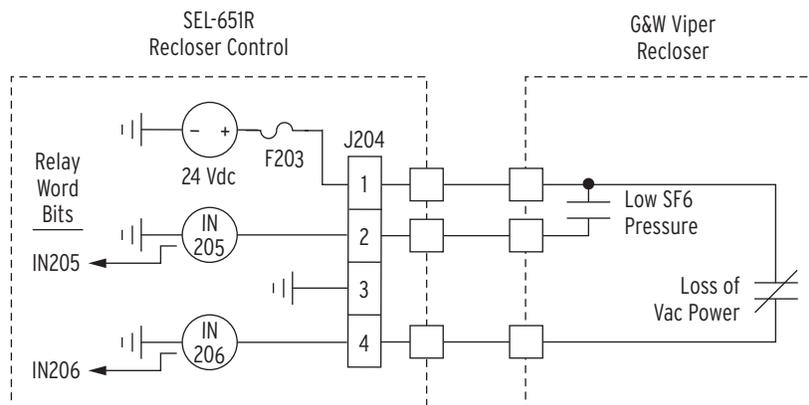
Figure 2.51   G&W Viper Recloser Extra Alarm Connections to SEL-651R-2

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G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-Pin) Reclosers

SHIELDED CABLES
Shielded cables for LEA voltage inputs (see Figure 2.52) come preinstalled on newer G&W/ABB Elastimold recloser installations, with the shields effectively connected to ground at the bottom of the enclosure.

Figure 2.52 shows the SEL-651R-2 factory wiring for current connections for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-pin) reclosers. The current transformers in the recloser are wired like a circuit breaker in that the residual path through control cable Pin D is on the nonpolarity side of the current transformer secondaries. This contrasts with the Traditional Retrofit recloser in *Figure 2.49*. Either wiring is easily accommodated by the wiring on the Z01–Z08 terminals of the SEL-651R-2 relay module.

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CAPACITIVE VOLTAGE SENSORS

To make use of the standard capacitive voltage sensors at the bottom of Figure 2.52, the SEL-651R-2 needs to be ordered with 8 Vac LEA voltage inputs for the three-phase VY voltage inputs. If both the standard and optional capacitive voltage sensors are to be used, then the SEL-651R-2 needs to be ordered with 8 Vac LEA voltage inputs for both the three-phase VY and VZ voltage inputs.

Other voltage input options are available, though not using the control cable shown in Figure 2.52 (see SEL-651R-2 Model Option Table).
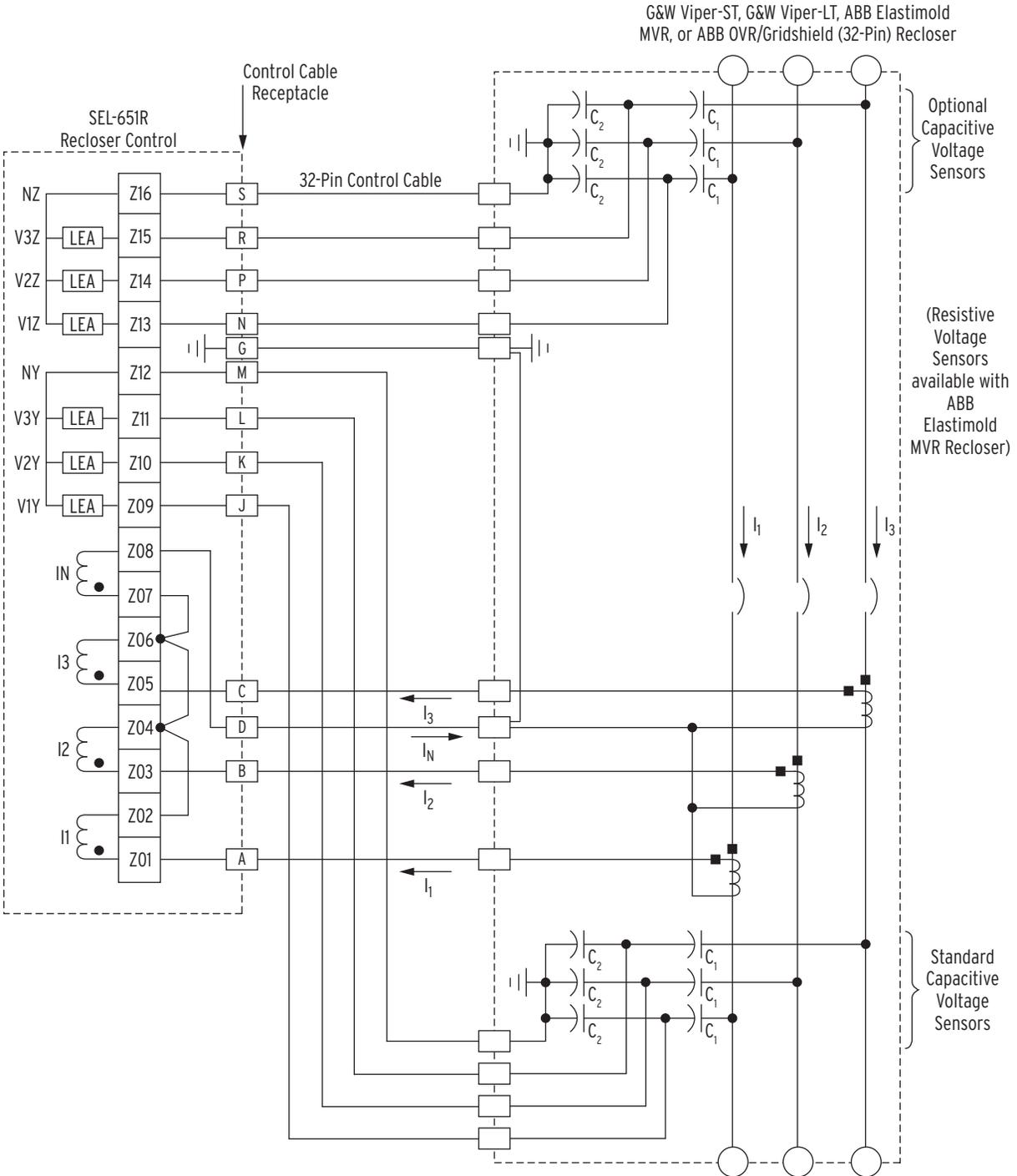
Figure 2.52   Current Connections and Polarity From G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-Pin) Recloser Primary to SEL-651R-2 Recloser Control Current Inputs (Voltage Connections Also Shown)

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Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow and similar things.

Figure 2.53 shows the SEL-651R-2 factory wiring for trip/close for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-pin) reclosers. Each pole of the recloser has its own trip/close coil, trip for current flow in one direction, close for current flow in the other direction. This facilitates single-phase tripping/reclosing, although the SEL-651R-2 factory settings have the recloser operating in a three-phase trip/close mode.

Note that the trip and close FETs in the SEL-651R-2 are stacked one atop another, between 155 Vdc power and ground, with a tap in the middle. For a given FET stack, both FETs can never be on at the same time or else there would be a direct short between the 155 Vdc power and ground. Interlocking logic prevents both FETs from being on at the same time.

Trace the trip path for Coil 1 in *Figure 2.53*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.26*) turns on the bottom FET (ground) connected to terminal J206-3 and the top FET (155 Vdc) connected to terminal J206-9. This wiring goes through control cable Pins Y/10 and Z/22 to Coil 1. The 155 Vdc across Coil 1 (bottom to top) causes the current to flow in the indicated direction (Trip 1).

Trace the close path for Coil 1 in *Figure 2.53*:

Relay Word Bit RCCL1X (Close 1; see *Figure 7.26*) turns on the top FET (155 Vdc) connected to terminal J206-3 and the bottom FET (ground) connected to terminal J206-9. This wiring goes through control cable Pins Y/10 and Z/22 to Coil 1. The 155 Vdc across Coil 1 (top to bottom) causes the current to flow in the indicated direction (Close 1).

Tripping and closing for Coil 2 and Coil 3 operate similarly. The 69 contacts in the trip/close circuits open and stay open when the respective external yellow operating handles on individual poles of the recloser are pulled to the lock-open position (the ABB Elastimold MVR and ABB OVR/Gridshield [32-pin] reclosers have only one yellow operating handle that simultaneously operates the 69 contacts in each pole). With Contact 69 open for a particular pole, there is no way to close that particular recloser pole until the yellow operating handle is reset again. Contact 69 is then closed.

RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 155 Vdc voltage in Figure 2.53 is present for recloser operations (TCCAP = logical 1). The 155 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8).

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Figure 2.53   Trip/Close Circuit Connections Between G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-pin) Recloser and SEL-651R-2 Recloser Control

Figure 2.54 shows inputs IN201–IN203 monitoring individual 52a recloser pole status. Input IN204 monitors the combined status of yellow operating handles for the individual recloser poles. The 69 contact closes for the corresponding yellow operating handle going to the lock-open position. Input IN204 is used in *Figure 5.2* logic.

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Figure 2.54   Recloser Pole Status and Yellow Operating Handle Circuit Connections Between G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, or ABB OVR/Gridshield (32-Pin) Recloser and SEL-651R-2 Recloser Control

ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Reclosers

SHIELDED CABLES
Shielded cables for LEA voltage inputs (see Figure 2.52) come preinstalled on newer ABB recloser installations, with the shields effectively connected to ground at the bottom of the enclosure.

LEA CIRCUIT GROUNDING

Figure 2.55 shows the connection from terminal Z12 to ground at the bottom of the enclosure that comes for newer ABB recloser installations. This connection grounds the recloser LEA circuit.

Figure 2.55 shows the SEL-651R-2 factory wiring for current connections for ABB OVR-3/VR-3S (24-pin, 15 and 27 kV models) reclosers. The current transformers in the recloser are wired like a circuit breaker in that the residual path through control cable Pin 12 is on the nonpolarity side of the current transformer secondaries. This contrasts with the Traditional Retrofit recloser in *Figure 2.49*. Either wiring is easily accommodated by the wiring on the Z01–Z08 terminals of the SEL-651R-2 relay module.

The VY voltage connections shown in *Figure 2.55* connect to low-energy analog (LEA) sensors internal to the ABB recloser (consult with ABB as to the location of their internal LEA sensors if their recloser is equipped with such). This requires that the VY voltage inputs on the SEL-651R-2 be ordered with 8 Vac LEA voltage inputs.

If the VY voltage inputs in *Figure 2.55* are instead connected to traditional potential transformers (e.g., those with 120 Vac nominal output), then this requires that the VY voltage inputs on the SEL-651R-2 be ordered with 300 Vac voltage inputs and that such circuits are brought in via means other than the 24-pin control cable. VZ voltage inputs are also available, and any connections to them are via means other than the 24-pin control cable. See the SEL-651R-2 Model Option Table (MOT) at selinc.com/products/651r/ for secondary input voltage options.

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Figure 2.55   Current Connections and Polarity From ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Recloser Primary to SEL-651R-2 Recloser Control Current Inputs

Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow and similar things.

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Figure 2.56 shows the SEL-651R-2 factory wiring for trip/close for ABB OVR-3/VR-3S (24-pin, 15 and 27 kV models) reclosers. Each pole of the recloser has its own trip/close coil, trip for current flow in one direction, close for current flow in the other direction. This facilitates single-phase tripping/reclosing, although the SEL-651R-2 factory settings have the recloser operating in a three-phase trip/close mode.

Note that the trip and close FETs in the SEL-651R-2 are stacked one atop another, between 53 Vdc power and ground, with a tap in the middle. For a given FET stack, both FETs can never be on at the same time or else there would be a direct short between the 53 Vdc power and ground. Interlocking logic prevents both FETs from being on at the same time.

Trace the trip path for Coil 1 in *Figure 2.56*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.26*) turns on the bottom FET (ground) connected to terminal J206-3 and the top FET (53 Vdc) connected to terminal J206-9. This wiring goes through control cable Pins 22 and 10 to Coil 1. The 53 Vdc across Coil 1 (bottom to top) causes the current to flow in the indicated direction (Trip 1).

Trace the close path for Coil 1 in *Figure 2.56*:

Relay Word Bit RCCL1X (Close 1; see *Figure 7.26*) turns on the top FET (53 Vdc) connected to terminal J206-3 and the bottom FET (ground) connected to terminal J206-9. This wiring goes through control cable Pins 22 and 10 to Coil 1. The 53 Vdc across Coil 1 (top to bottom) causes the current to flow in the indicated direction (Close 1).

Tripping and closing for Coil 2 and Coil 3 operate similarly.

RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 53 Vdc voltage in Figure 2.56 is present for recloser operations (TCCAP = logical 1). The 53 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8).

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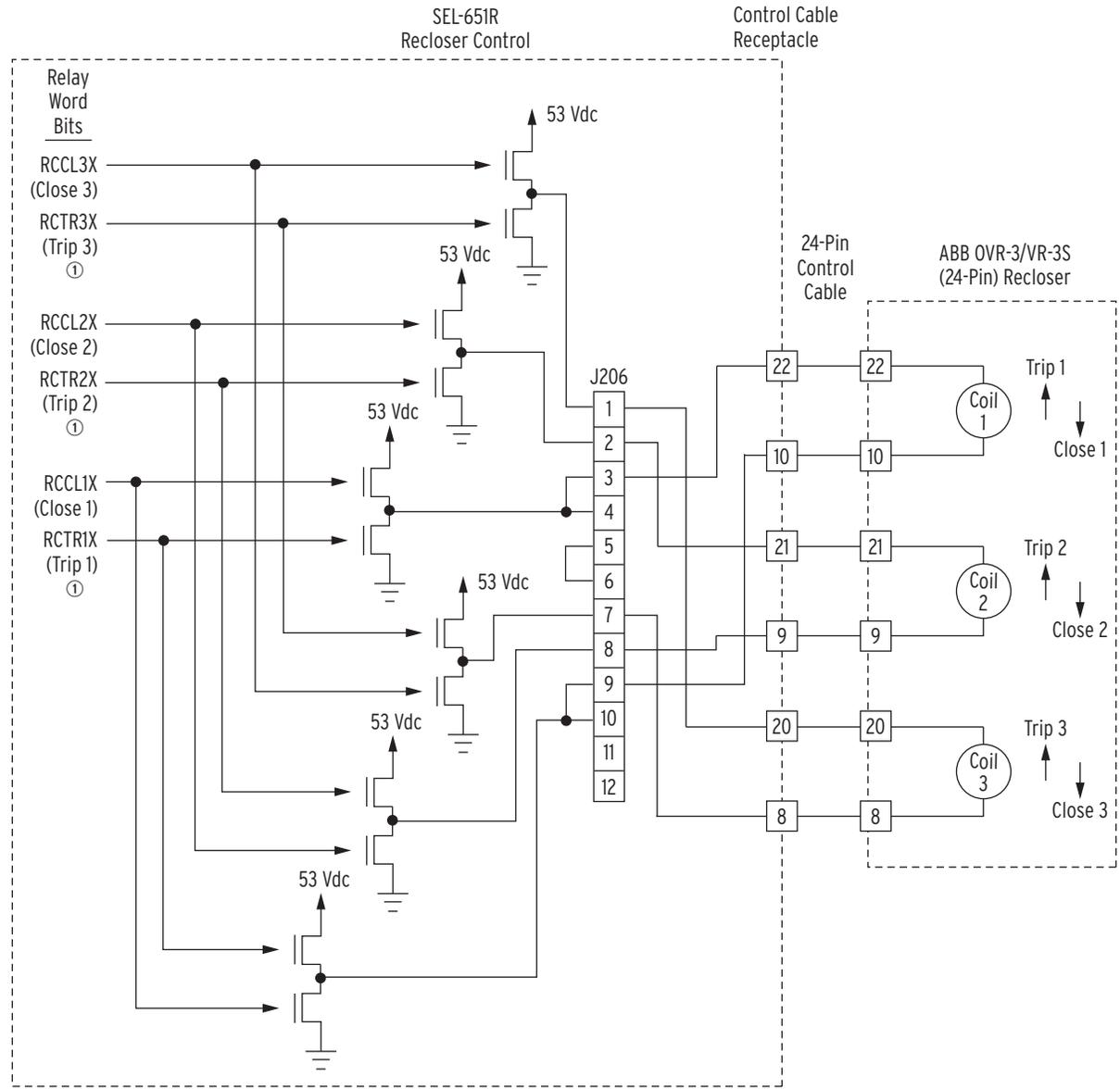
① See Figure 7.26

Figure 2.56   Trip/Close Circuit Connections Between ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Recloser and SEL-651R-2 Recloser Control

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Figure 2.57 shows inputs IN201–IN203 monitoring individual 52b recloser pole status and inputs IN105–IN107 monitoring individual 52a recloser pole status. Input IN204 monitors the status of the yellow operating handle. The 69 contact closes for the yellow operating handle going to the lock-open position.
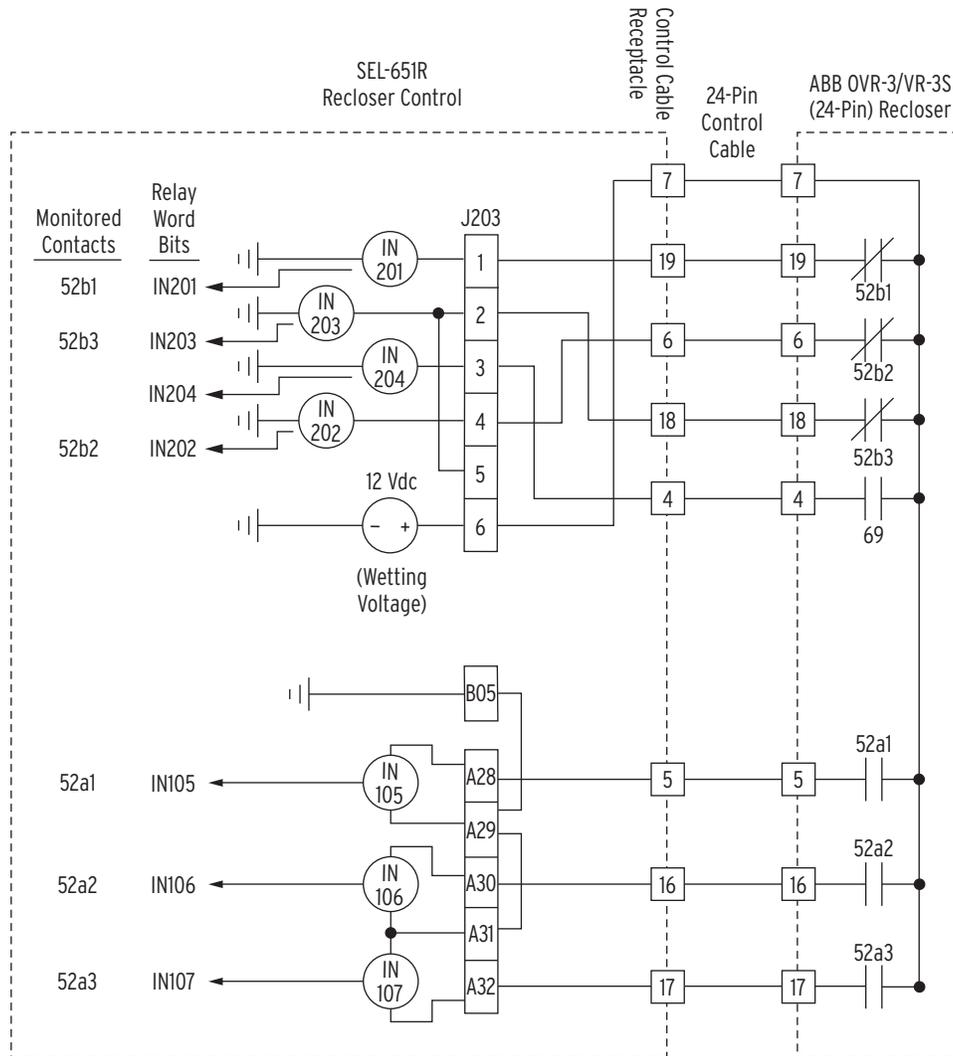
Figure 2.57   Recloser Pole Status and Yellow Operating Handle Circuit Connections Between ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Recloser and SEL-651R-2 Recloser Control

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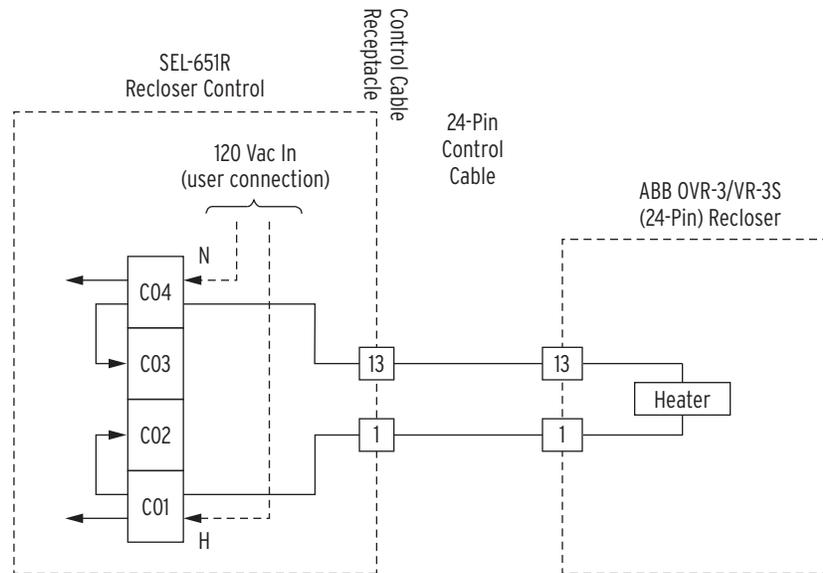
Figure 2.58   120 Vac Power Circuit Connections Between SEL-651R-2 Recloser Control and ABB OVR-3/VR-3S (24-Pin, 15 and 27 kV Models) Recloser

Figure 2.58 shows the routing of 120 Vac power through the 24-pin control cable to heaters in the ABB OVR-3/VR-3S (24-pin, 15 and 27 kV models) reclosers.

Control-Powered Eaton NOVA or G&W Control Power Viper-S Reclosers

Figure 2.59 shows the SEL-651R-2 factory wiring for current connections for Control-Powered Eaton NOVA or G&W Control Power Viper-S reclosers. Notice that the current transformers in the recloser are wired such that the residual path (through Pin K) is on the polarity side of the current transformer secondaries. This is nonstandard as far as traditional circuit breakers are concerned, but is easily accommodated by the wiring on the Z01–Z08 terminals of the relay module of the SEL-651R-2.

Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow, and so forth.

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Figure 2.59   Current Connections and Polarity From Control-Powered Eaton NOVA or G&W Control Power Viper-S Recloser Primary to SEL-651R-2 Recloser Control Current Inputs

Figure 2.60 shows the SEL-651R-2 factory wiring for trip/close/recloser status for Control-Powered Eaton NOVA or G&W Control Power Viper-S reclosers; 53 Vdc power goes out Pins R, S, T to the recloser and then returns through the trip circuit and close circuit paths.

Pin C is monitored by input IN201. The 52a recloser status is derived from this input.

If the Control-Powered Eaton NOVA or G&W Control Power Viper-S reclosers are not VTC-equipped, then the signals to Pin F and IN206 can be ignored—they will not affect normal recloser operation. VTC-equipped reclosers cannot trip/close without the 24 Vdc signal to Pin F.

IN205 monitors the 53 Vdc trip/close voltage output from J204-1. When this voltage is present, IN205 is asserted. IN206 monitors the 12/24 Vdc converter. If the 12/24 Vdc converter is operating correctly, then IN206 is asserted. Use IN205 or IN206 as an alarm, routing it to an LED, front-panel display point, SCADA output, or an output contact (e.g., make the following settings: ESV := 2, SV02PU := 600 cycles, SV02DO := 600, SV02 := NOT [IN206], and OUT202 := SV02T. OUT202 asserts, providing an alarm, if the 12/24 Vdc converter fails).

RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 53 Vdc voltage in Figure 2.60 is present for recloser operations (TCCAP = logical 1). The 53 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8). Relay Word bit TCCAP does not detect an operation of fuse F203 in Figure 2.60.
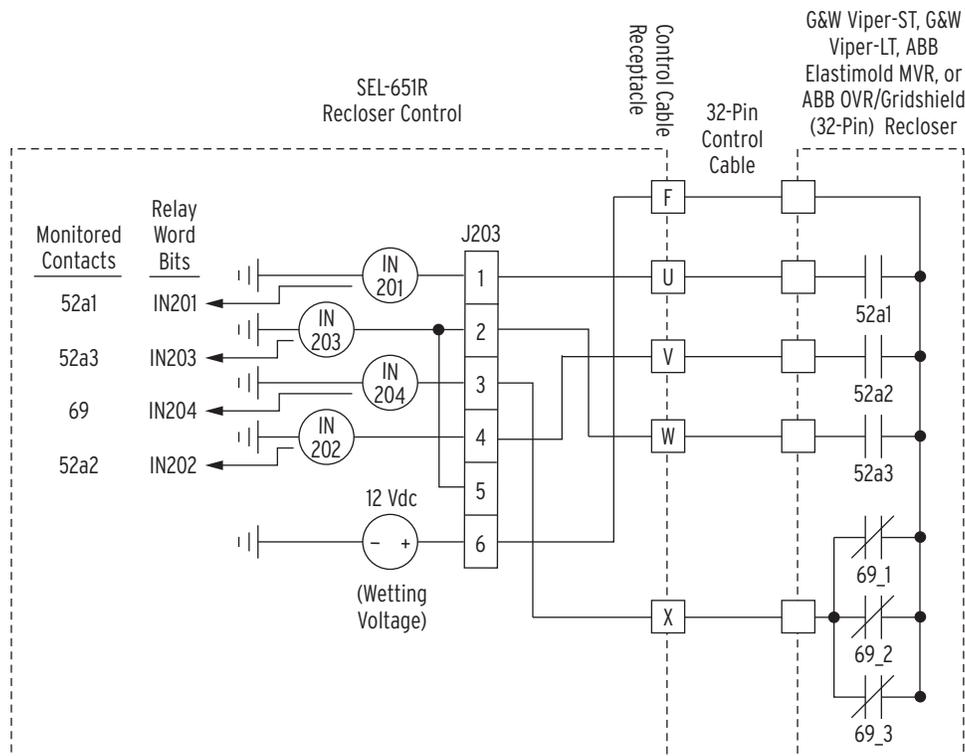
① See Figure 7.25.

Figure 2.60   Trip/Close and Recloser Status Circuit Connections Between Control-Powered Eaton NOVA or G&W Control Power Viper-S Recloser and SEL-651R-2 Recloser Control

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Figure 2.61 shows the routing of 120 Vac power through the 19-pin control cable to heaters in the Control-Powered Eaton NOVA or G&W Control Power Viper-S reclosers.
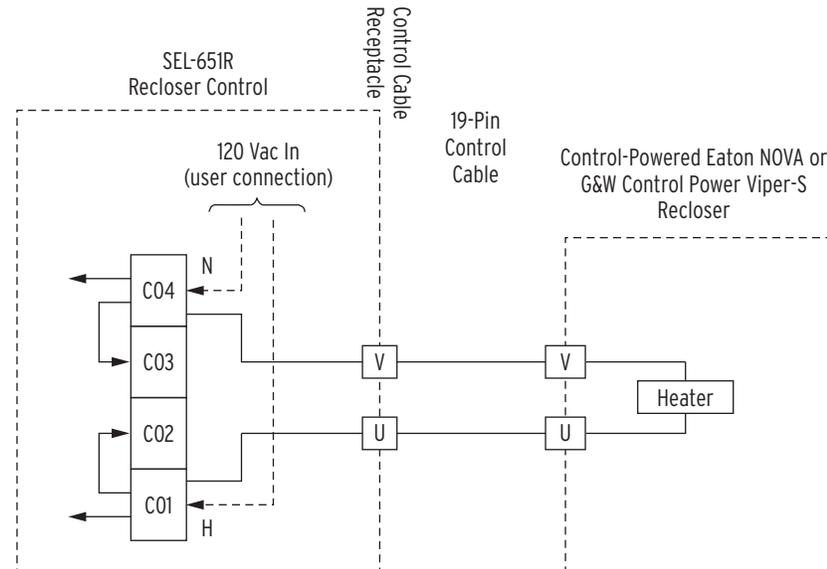
Figure 2.61   120 Vac Power Circuit Connections Between SEL-651R-2 Recloser Control and Control-Powered Eaton NOVA or G&W Control Power Viper-S Recloser

ABB Joslyn TriMod 600R Reclosers

Figure 2.62 shows the SEL-651R-2 factory wiring for current connections for ABB Joslyn TriMod 600R reclosers. The current transformers in the recloser are wired like a circuit breaker in that the residual path through control cable pins is on the nonpolarity side of the current transformer secondaries. This contrasts with the Traditional Retrofit recloser in *Figure 2.49*. Either wiring is easily accommodated by the wiring on the Z01–Z08 terminals of the SEL-651R-2 relay module.
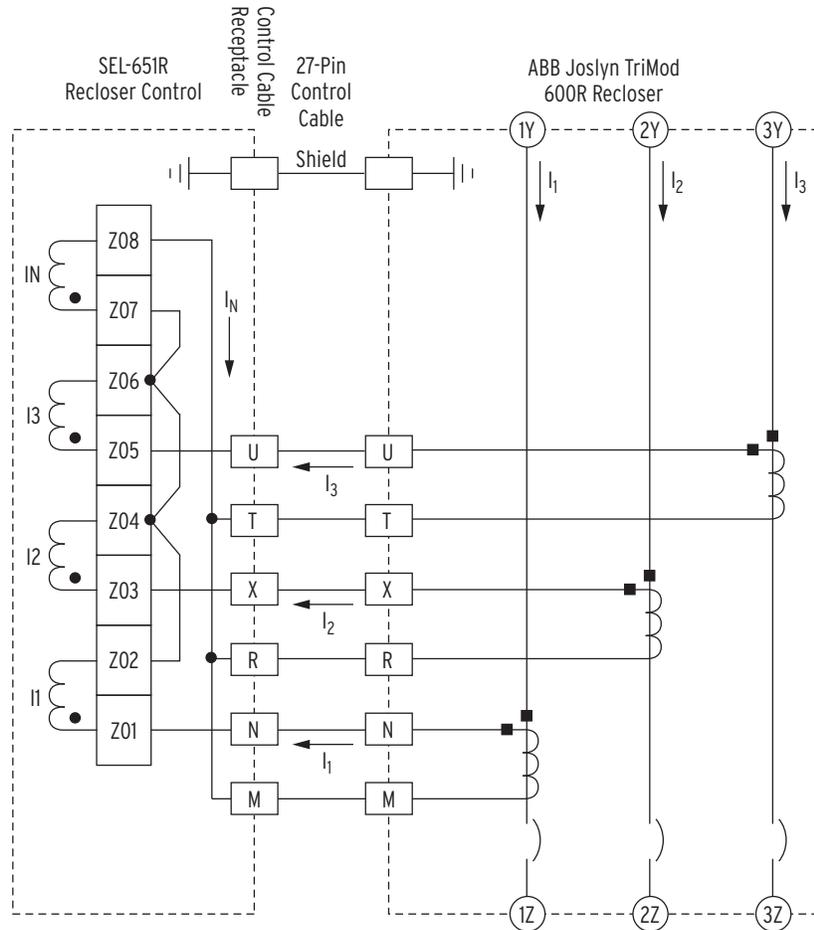
Figure 2.62   Current Connections and Polarity From ABB Joslyn TriMod 600R Recloser Primary to SEL-651R-2 Recloser Control Current Inputs

Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow and similar things.

Figure 2.63 shows the SEL-651R-2 factory wiring for trip/close for ABB Joslyn TriMod 600R reclosers. Each pole of the recloser has its own trip and close coils. This facilitates single-phase tripping/reclosing, although the SEL-651R-2 factory settings have the recloser operating in a three-phase trip/close mode.

RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 155 Vdc voltage in Figure 2.63 is present for recloser operations (TCCAP = logical 1). The 155 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8).

Trace the trip path for Coil 1 in *Figure 2.63*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.26*) turns on the FET (155 Vdc) connected to terminal J206-9. This wiring goes through control cable Pins H and I to Trip Coil 1. The 155 Vdc across Trip Coil 1 causes the current to flow through the coil.

Trace the close path for Coil 1 in *Figure 2.63*:

Relay Word Bit RCCL1X (Close 1; see *Figure 7.26*) turns on the FET (155 Vdc) connected to terminal J206-3. This wiring goes through control cable Pins A and C to Coil 1. The 155 Vdc across Close Coil 1 causes the current to flow through the coil.

Tripping and closing for phases 2 and 3 operate similarly.

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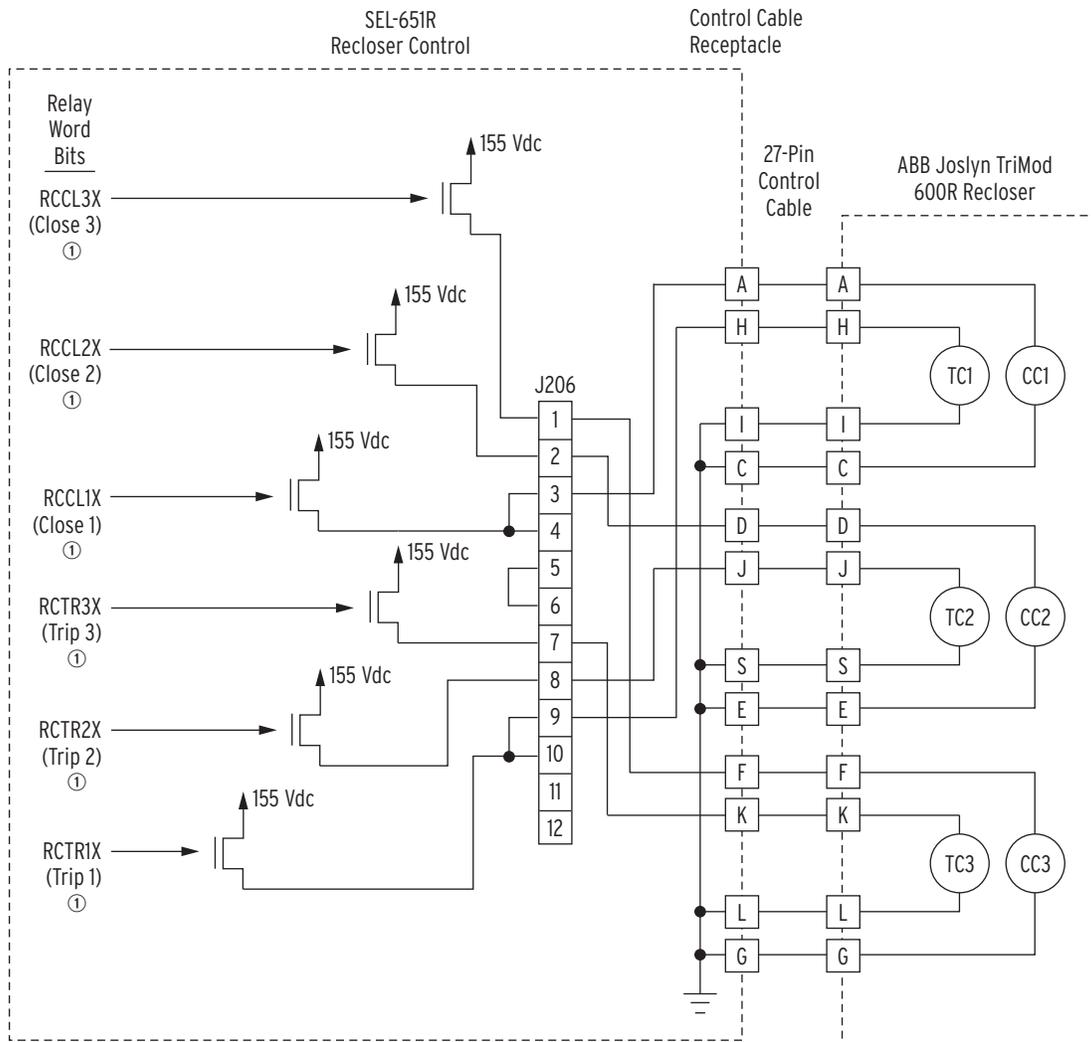
① See Figure 7.26

Figure 2.63 Trip/Close Circuit Connections Between ABB Joslyn TriMod 600R Recloser and SEL-651R-2 Recloser Control

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Recloser Interface Connection Details (Control Cable Interface)

Figure 2.64 shows inputs IN201–IN203 monitoring individual 52a recloser pole status. Input IN204 monitors the status of the yellow operating handle. The yellow operating handle mechanically trips all three phases, and the 69 contact opens for the yellow operating handle going to the lock-open position.
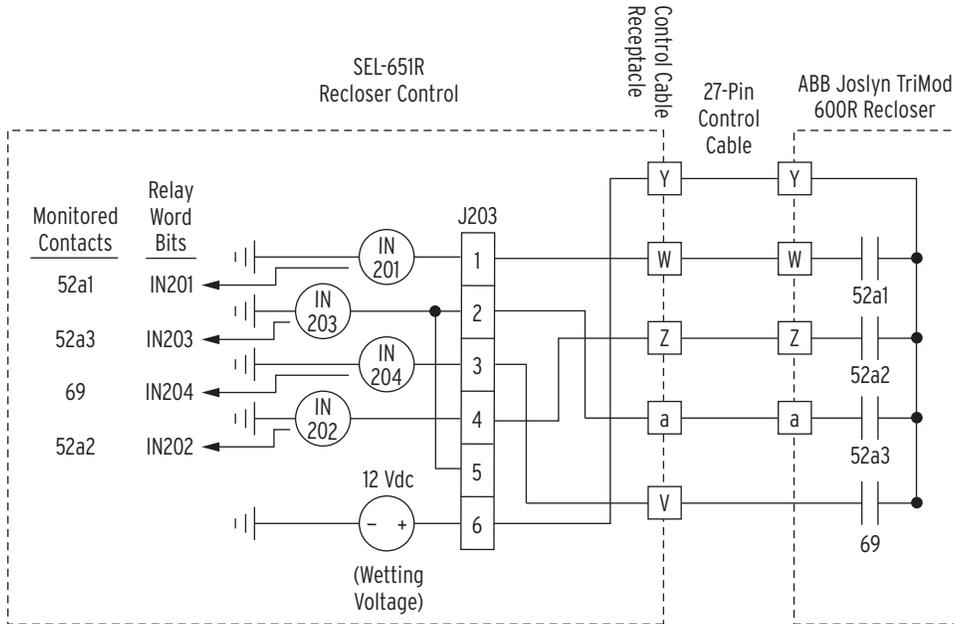
Figure 2.64 Recloser Pole Status Circuit Connections Between ABB Joslyn TriMod 600R Recloser and SEL-651R-2 Recloser Control

Eaton NOVA-TS or NOVA-STS Triple-Single Reclosers

RESISTIVE VOLTAGE SENSORS

To make use of the optional resistive voltage sensors in Figure 2.65, the SEL-651R-2 needs to be ordered with Eaton NOVA LEA voltage inputs for the three-phase VY voltage inputs. See Table 9.11 for voltage phase angle correction settings for such voltage inputs.

Other voltage input options are available, though not using the control cable shown in Figure 2.65 (see SEL-651R-2 Model Option Table).

Figure 2.65 shows the SEL-651R-2 factory wiring for current connections for Eaton NOVA-TS or NOVA-STS Triple-Single reclosers. Notice that the current transformers in the recloser are wired such that the residual path (through Pin Y) is on the polarity side of the current transformer secondaries. This is nonstandard as far as traditional circuit breakers are concerned, but is easily accommodated by the wiring on the Z01–Z08 terminals of the relay module of the SEL-651R-2.

Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow and similar things.

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Figure 2.65   Current Connections and Polarity From Eaton NOVA-TS or NOVA-STS Triple-Single Recloser Primary to SEL-651R-2 Recloser Control Current Inputs (Voltage Connections Also Shown)

Figure 2.66 shows the SEL-651R-2 factory wiring for trip/close for Eaton NOVA-TS or NOVA-STS Triple-Single reclosers. Each pole of the recloser has its own trip/close coils. This facilitates single-phase tripping/reclosing, although the SEL-651R-2 factory settings have the recloser operating in a three-phase trip/close mode.

Trace the trip path for Trip Coil 1 in *Figure 2.66*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.25*) turns on the FET (ground) connected to terminal J206-3. This wiring goes through control cable Pin E and on to contact 52a_1 and Trip Circuitry 1.

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RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 53 Vdc voltage in Figure 2.66 is present for recloser operations (TCCAP = logical 1). The 53 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8). Relay Word bit TCCAP does not detect an operation of fuse F203 in Figure 2.66.

Trace the close path for Close Coil 1 in *Figure 2.66*:

Relay Word bit RCCL1X (Close 1; see *Figure 7.25*) turns on the FET (ground) connected to terminal J206-9. This wiring goes through control cable Pin H and on to contact 52b_1 and Close Circuitry 1.

Tripping and closing for phases 2 and 3 operate similarly.

See *Figure 2.67*. The operation of any individual yellow lockout handle on the Eaton NOVA-TS or NOVA-STS Triple-Single recloser results in the opening/lockout of that phase (if not already open) and the opening of the corresponding "69" contact (69_1, 69_2, or 69_3) and the subsequent assertion of the corresponding input (IN204, IN205, or IN206) in the SEL-651R-2. Inputs IN204, IN205, and IN206 are effectively used in default SELOGIC control equation trip setting TR3X to trip the other two phases when the yellow lockout handle of one phase is operated (see *Figure 5.2*).

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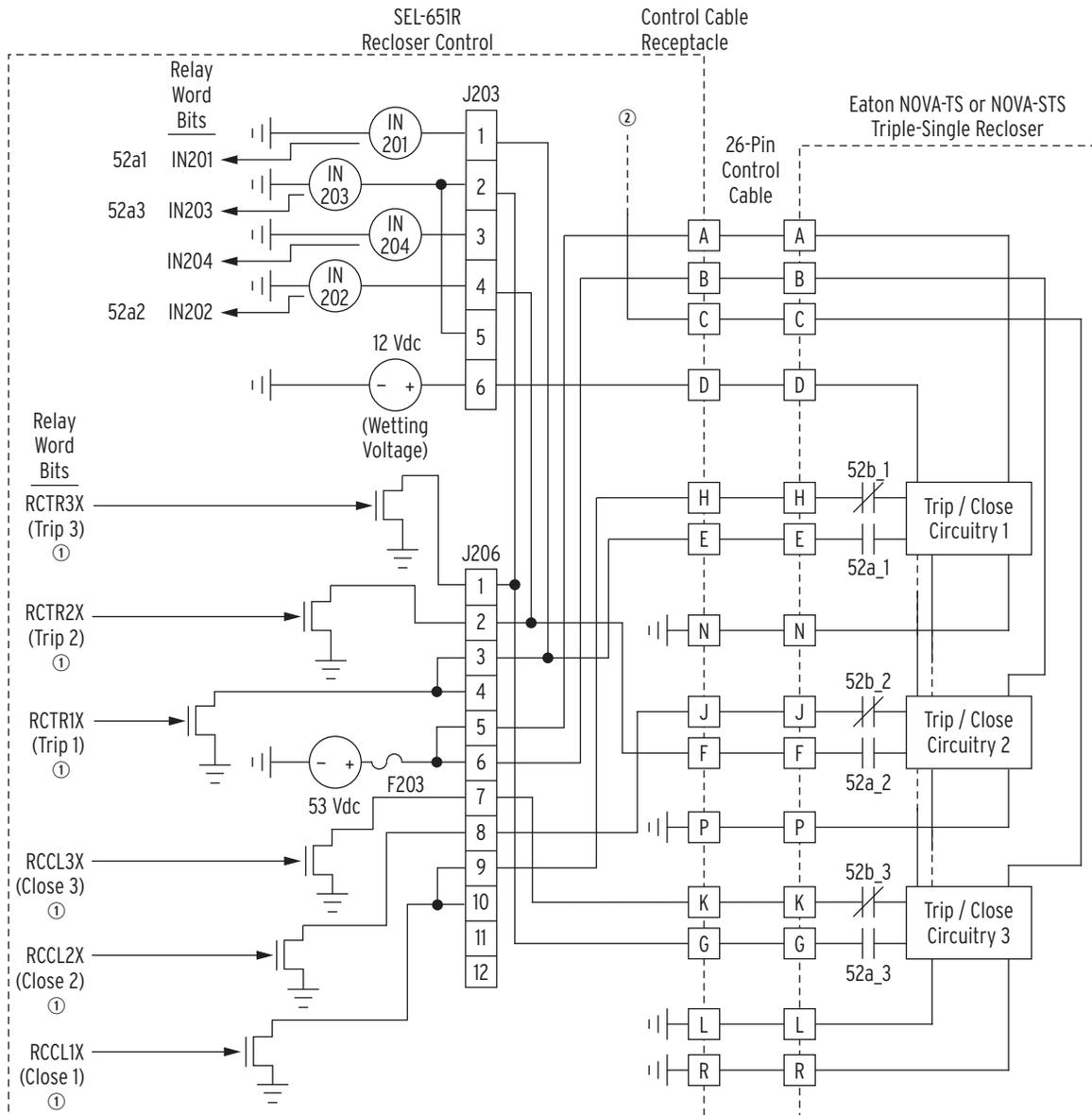
① See Figure 7.25; ② See Figure 2.67 and connection to Pin C from Terminal J204-1

Figure 2.66   Trip/Close and Recloser Pole Status Circuit Connections Between Eaton NOVA-TS or NOVA-STS Triple-Single Recloser and SEL-651R-2 Recloser Control

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① See Figure 2.66 for the continuation of the Pin C circuit in the recloser
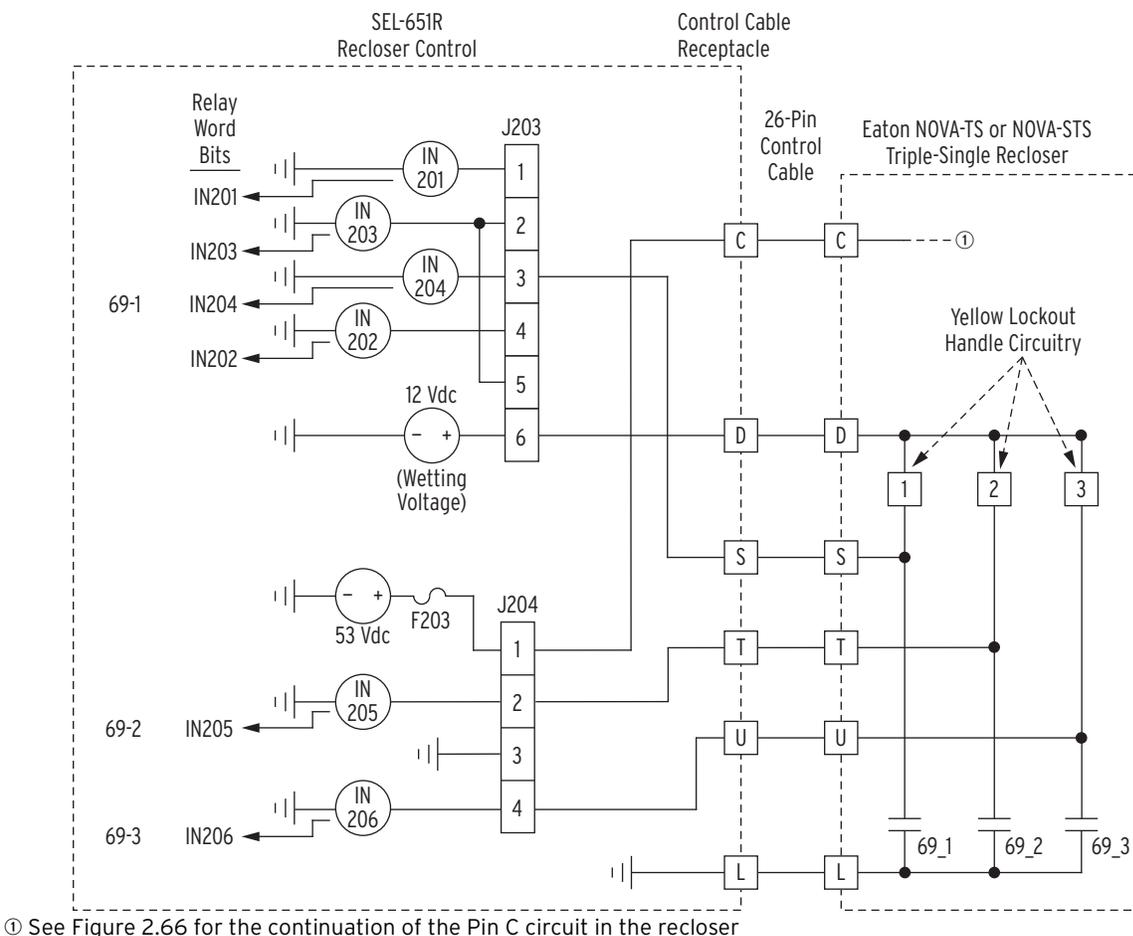
Figure 2.67   Yellow Lockout Handle Circuit Connections Between Eaton NOVA-TS or NOVA-STS Triple-Single Recloser and SEL-651R-2 Recloser Control

Tavrida OSM Al_2 Recloser

Figure 2.68 shows the SEL-651R-2 factory wiring for current and voltage connections for the Tavrida OSM Al_2 recloser. The current transformers in the recloser are wired like a circuit breaker in that the residual path through control cable Pin 14 is on the nonpolarity side of the current transformer secondaries. This contrasts with the Traditional Retrofit recloser in *Figure 2.49*. Either wiring is easily accommodated by the wiring on the Z01–Z08 terminals of the SEL-651R-2 relay module.

Notice also that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC) in *Figure 2.68*. A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow and similar things.
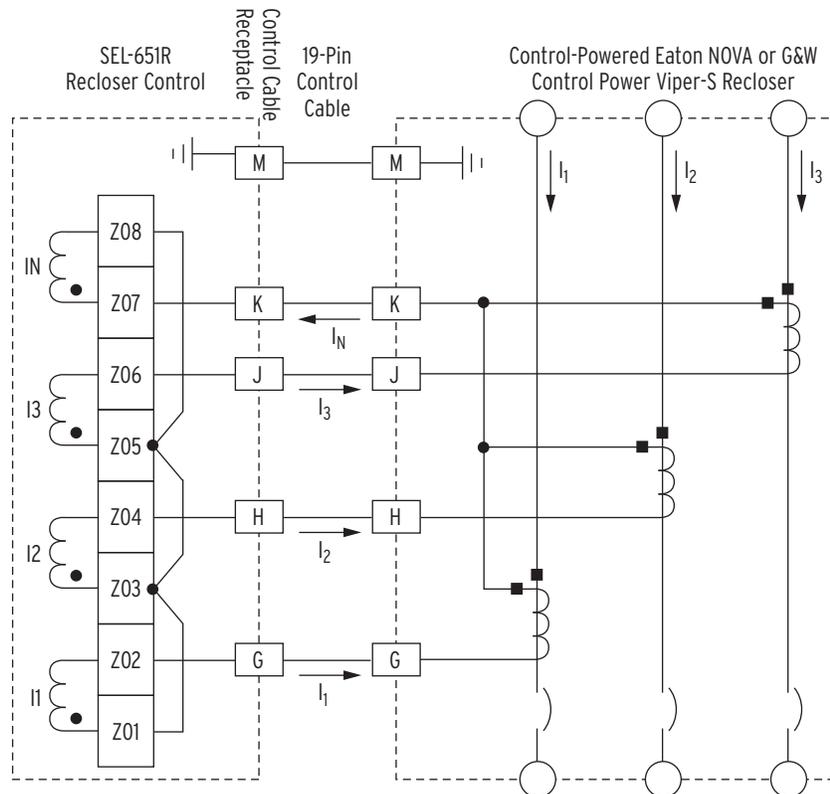
The Tavrida OSM Al_2 recloser has built-in capacitive voltage sensors (signified with capacitance C_1 in *Figure 2.68*) that are connected to the 8 Vac LEA voltage inputs of the SEL-651R-2 via capacitance C_2 (capacitances C_1 and C_2 making an effective voltage divider). See *Factory-Default Settings on page 9.61* for the required potential transformer ratio settings PTRY (for VY-terminal voltage inputs) and PTRZ (for VZ-terminal voltage inputs) that allow the SEL-651R-2 to meter correctly with the capacitive voltage sensors of the Tavrida OSM Al_2 recloser.

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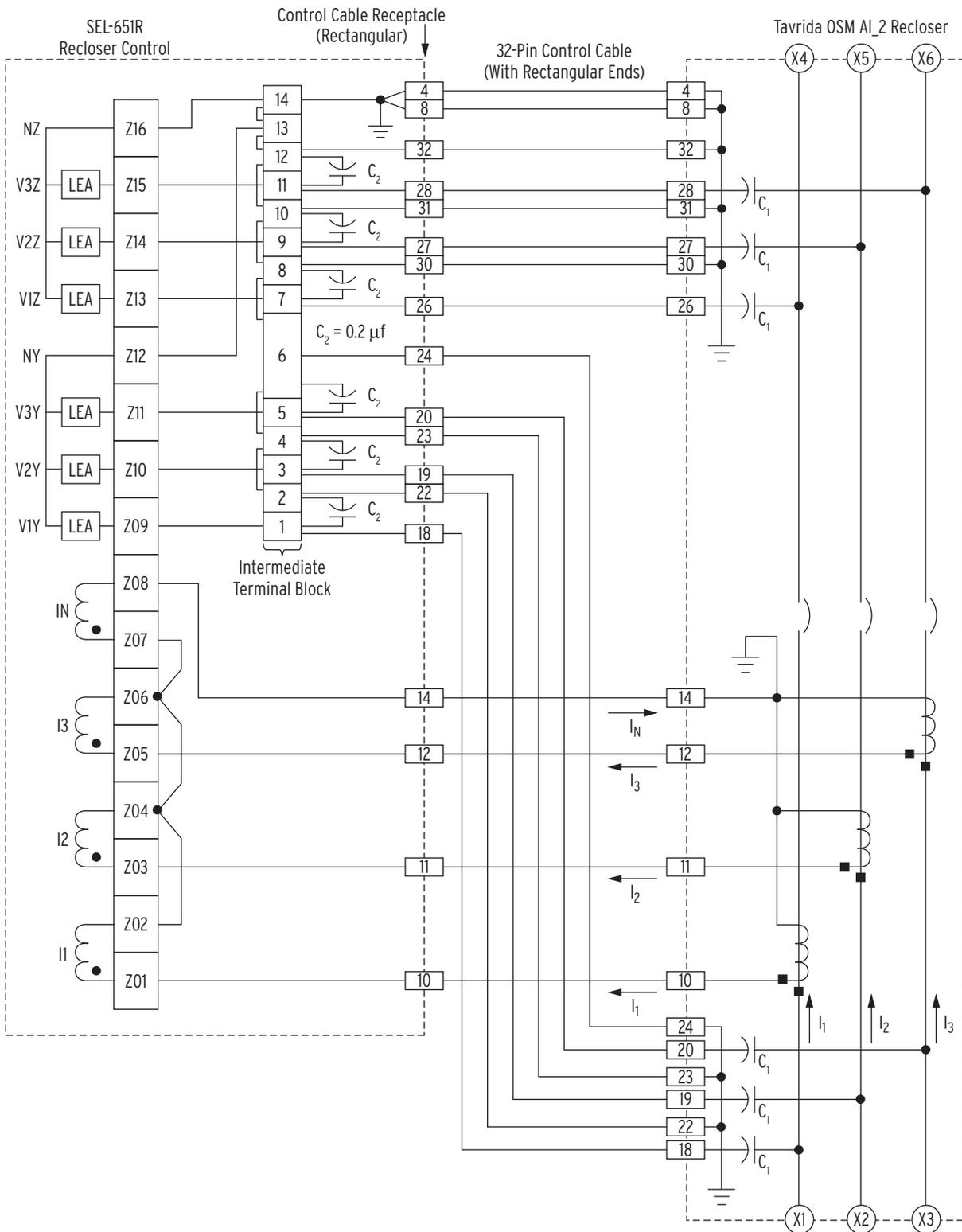
Figure 2.68   Current Connections and Polarity From Tavrida OSM AI_2 Recloser Primary to SEL-651R-2 Recloser Control Current Inputs (Voltage Connections Also Shown)

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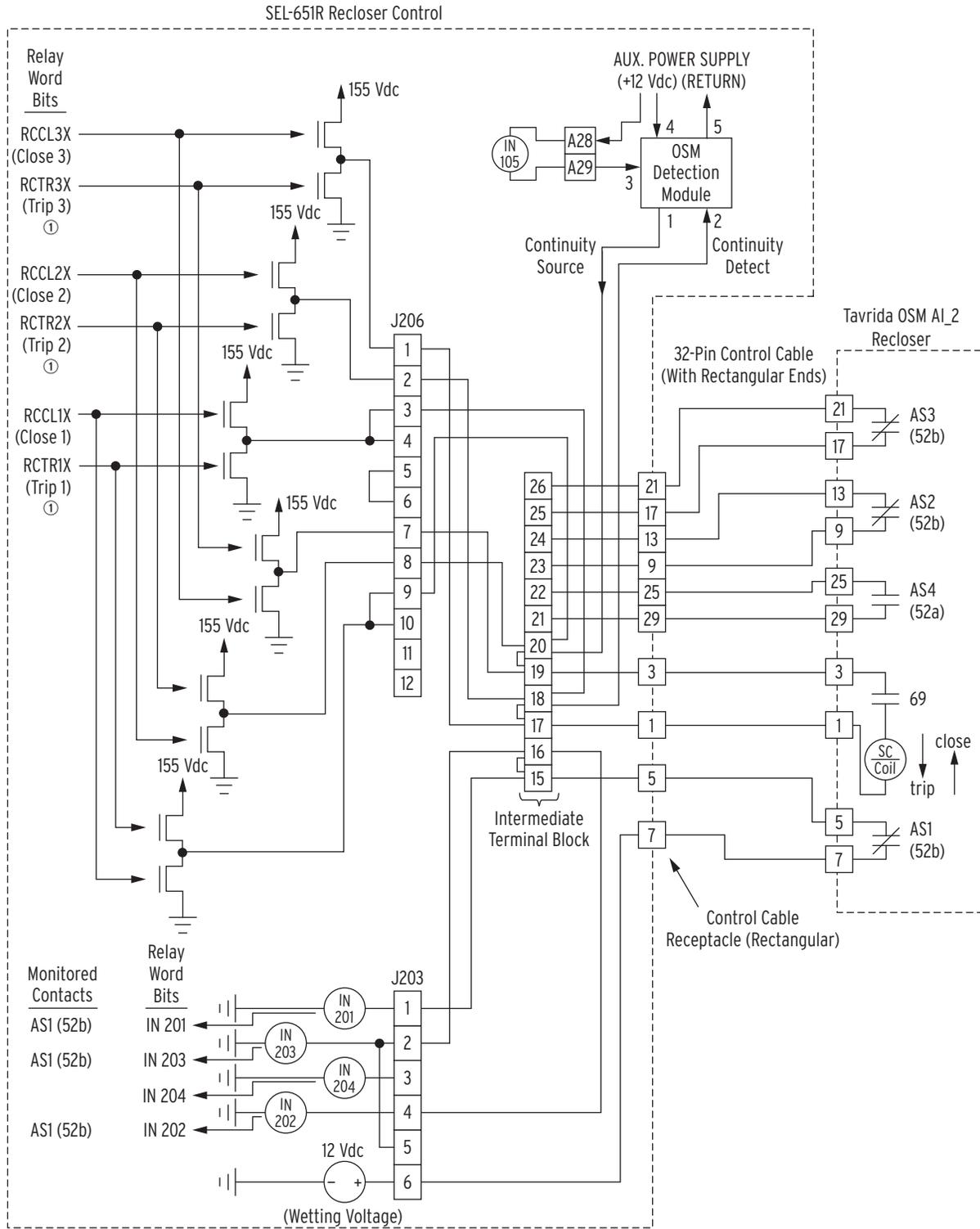
Figure 2.69   Trip/Close and Recloser Status Circuit Connections Between Tavrida OSM AI_2 Recloser and SEL-651R-2 Recloser Control

① See Figure 7.26

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RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 155 Vdc voltage in Figure 2.69 is present for recloser operations (TCCAP = logical 1). The 155 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8).

The parallel connections shown between terminals 2, 4, 6, 8, 10, 12, 13, and 14 on the left-hand side of the intermediate terminal block in *Figure 2.68* are realized with hidden busing inside the intermediate terminal block itself. Terminal 14 of the intermediate terminal block is then taken to cabinet ground.

The Tavrida OSM Al_2 recloser operates as a three-phase trip/three-phase close device—it does not have single-phase tripping/closing capability. There is only one trip/close coil (referenced as SC/coil in *Figure 2.69*) for the Tavrida OSM Al_2 recloser: trip for current flow in one direction, close for current flow in the other direction.

In *Figure 2.69*, note that the trip and close FETs in the SEL-651R-2 are stacked on top of one another, between 155 Vdc power and ground, with a tap in the middle. For a given FET stack, both FETs can never be on at the same time or else there would be a direct short between the 155 Vdc power and ground. Interlocking logic prevents both FETs from being on at the same time.

Also, note that there are redundant trip/close circuits connected to SC/coil:

➤ Three FET stacks (top trip FET/bottom close FET) paralleled to terminals 19 and 20 of the intermediate terminal block in *Figure 2.69*

➤ Three FET stacks (top close FET/bottom trip FET) paralleled to terminals 17 and 18 of the intermediate terminal block in *Figure 2.69*

Trace one of the trip paths in *Figure 2.69*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.26*) turns on the bottom trip FET (ground) connected to terminal J206-3 (then terminal 18 of the intermediate terminal block) and the top trip FET (155 Vdc) connected to terminal J206-9 (then terminal 20 of the intermediate terminal block). This wiring continues through control cable Pin 3 and Pin 1 to SC/coil in the Tavrida OSM Al_2 recloser. The 155 Vdc across SC/coil (top to bottom) causes the current to flow in the indicated trip direction.

Trace one of the close paths in *Figure 2.69*:

Relay Word Bit RCCL1X (Close 1; see *Figure 7.26*) turns on the top close FET (155 Vdc connected to terminal J206-3 (then terminal 18 of the intermediate terminal block) and the bottom close FET (ground) connected to terminal J206-9 (then terminal 20 of the intermediate terminal block). This wiring continues through control cable Pin 3 and Pin 1 to SC/coil in the Tavrida OSM Al_2 recloser. The 155 Vdc across SC/coil (bottom to top) causes the current to flow in the indicated close direction.

The other paralleled trip/close circuits in *Figure 2.69* operate similarly. Relay Word bits RCTR1X, RCTR2X, and RCTR3X all operate the same—their controlling SELOGIC settings (see *Figure 7.26*) are set the same in default settings. Likewise, Relay Word bits RCCL1X, RCCL2X, and RCCL3X all operate the same—their controlling SELOGIC settings (see *Figure 7.26*) are set the same in default settings.

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A single 52b contact (AS1) is connected in parallel to inputs IN201, IN202, and IN203 as shown in *Figure 2.69* for recloser status. With the following *Factory-Default Settings on page 9.61* for the Tavrida OSM Al_2 recloser:

Global setting BKTYP := **1**

Group setting ESPB := **N**

Group settings 52A_A := **NOT IN201**, 52A_B := **NOT IN202**, 52A_C := **NOT IN203**

these three paralleled inputs only provide a three-phase open/three-phase closed status, not a per-pole recloser status (see resultant 52A3P Relay Word bit in *Figure 6.2*). It is irrelevant that IN201 is apparently assigned to an A-phase designation (52A_A := NOT IN201) and likewise IN202 with B-phase (52A_B := NOT IN202) and IN203 with C-phase (52A_C := NOT IN203). Resultant Relay Word bit 52A3P only conveys three-phase open/three-phase closed status, not any single-phase status.

Contacts AS2, AS3, and AS4 are brought to the intermediate terminal block in *Figure 2.69*, but are not connected to the SEL-651R-2.

When the external yellow operating handle on the Tavrida OSM Al_2 recloser is pulled to the lock-open position, the following occurs:

➤ The Tavrida OSM Al_2 recloser trips open (if not already open).

➤ The 69 contact in the trip/close circuit (*Figure 2.69*) opens and stays open.

With contact 69 open, there is no way to close the Tavrida recloser until the yellow operating handle is reset again. With the yellow operating handle reset, contact 69 in the trip/close circuit is closed again and the Tavrida recloser can then be closed by the SEL-651R-2.

Yellow Operating Handle Status

Input IN105 in *Figure 2.69* indicates yellow operating handle status:

➤ IN105 asserted (yellow operating handle in reset position and contact 69 closed in trip/close circuit)

➤ IN105 deasserted (yellow operating handle in lock-open position and contact 69 open in trip/close circuit)

The OSM Detection Module senses contact 69 position (open or closed) in the trip/close circuit, via the continuity source and detect connections. The OSM Detection Module then controls the assertion/deassertion of input IN105.

The following factory-default settings for the Tavrida OSM Al_2 recloser provide a front-panel display indication of the yellow operating handle status (reset or lock-open), qualified for 150 cycles.

SHO L Command

ESV := **3**

SV02PU := **150.00**

SV02DO := **150.00**

SV02 := **IN105 # QUALIFY YELLOW HANDLE OPERATION**

SHO F Command

EDP := **4**

DP03 := **SV02T,"YELLOW HANDLE",RESET,LOCK-OPEN**

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Disconnected Control Cable Alarm

Input IN105, from *Figure 2.69*, combined with recloser status (Relay Word bit 52A3P) provides a disconnected control cable alarm. If the control cable is disconnected in *Figure 2.69*, then inputs IN105, IN201, IN202, and IN203 are all deasserted, thus indicating the following contradictory condition.

➤ yellow operating handle in lock-open position (input IN105 deasserted)

➤ recloser closed (52b inputs IN201, IN202, and IN203 are all deasserted)

If "recloser closed," then the yellow operating handle must be reset. Pulling the yellow operating handle to lock-open causes the recloser to open and remain open. Thus, the condition "recloser closed" and yellow operating handle "lock-open" is an abnormal/alarm condition and is indicative of a disconnected control cable.

The following factory-default settings for the Tavrida OSM Al_2 recloser provide a front-panel display indication of a disconnected control cable, qualified for 150 cycles.

SHO L Command

ESV := **3**

SV03PU := **150.00**

SV03DO := **150.00**

SV03 := **NOT(IN105) AND 52A3P # QUALIFY DISCONNECTED CABLE**

SHO F Command

EDP := **4**

DP04 := **SV03T,,"CABLE DISCONNECTED"**

Siemens SDR Reclosers

Figure 2.70 and *Figure 2.71* show the SEL-651R-2 factory wiring for current connections for Siemens SDR Triple-Single and Siemens SDR Three-Phase reclosers, respectively. Note that the phase current terminals are labeled I1, I2, I3 (not IA, IB, IC) in *Figure 2.70* and *Figure 2.71*. A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the global CTPOL setting, which is helpful for designating forward or reverse power flow and similar things.
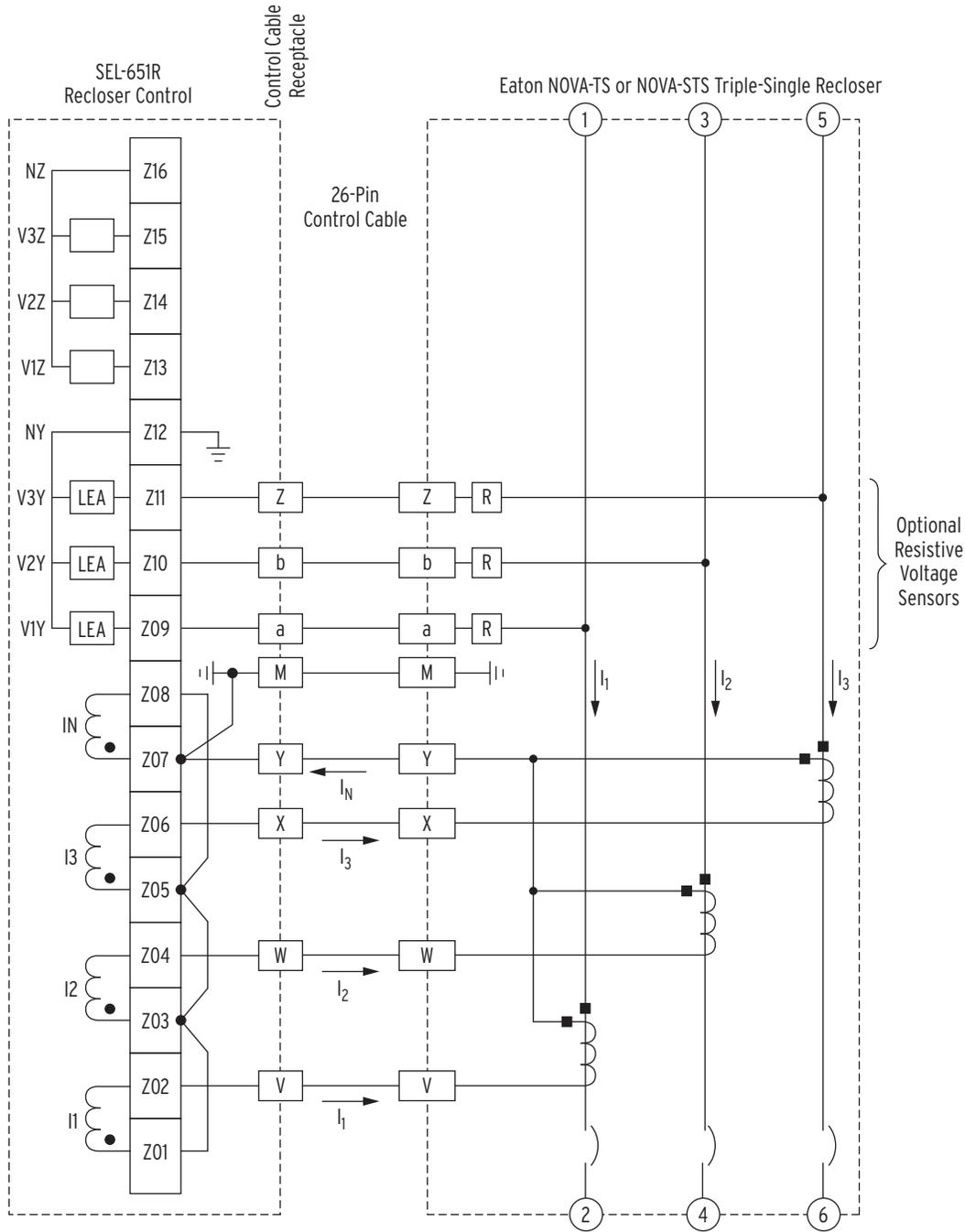
The Siemens SDR reclosers have optional built-in resistive voltage sensors (signified with resistance R in the recloser tanks in *Figure 2.70* and *Figure 2.71*) that are connected to the VZ-terminal Siemens LEA voltage inputs of the SEL-651R-2 (resistance R in the recloser tank and resistance in the Siemens LEA voltage inputs making an effective voltage divider). See *Table 9.14* and *Figure 9.24* for the required phase angle correction settings and potential transformer ratio settings, respectively, that allow the SEL-651R-2 to meter primary voltage correctly with the resistive voltage sensors of the Siemens SDR reclosers.
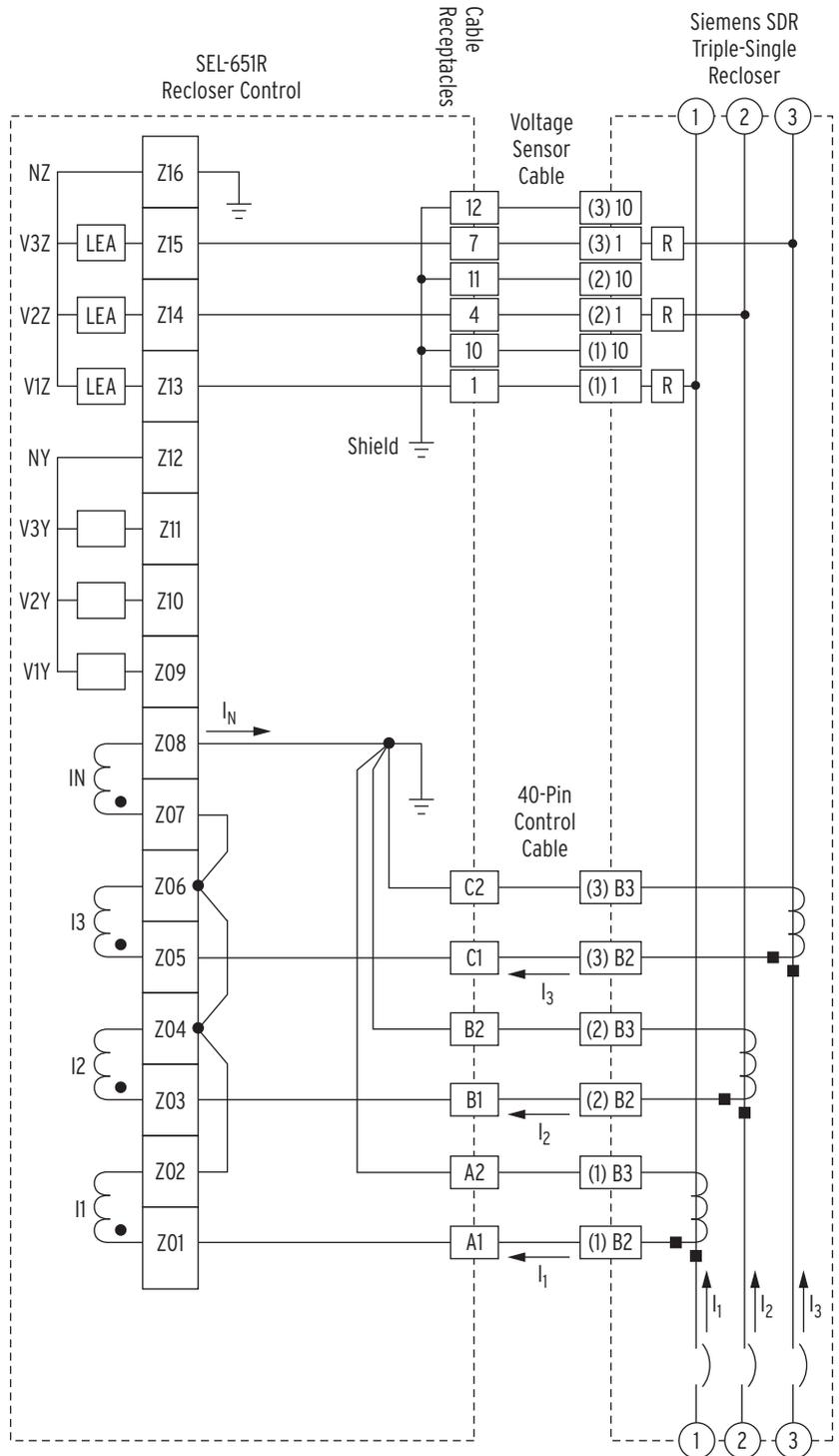
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Figure 2.7O Current Connections and Polarity From Siemens SDR Triple-Single Recloser Primary to SEL-651R-2 Recloser Control Current Inputs

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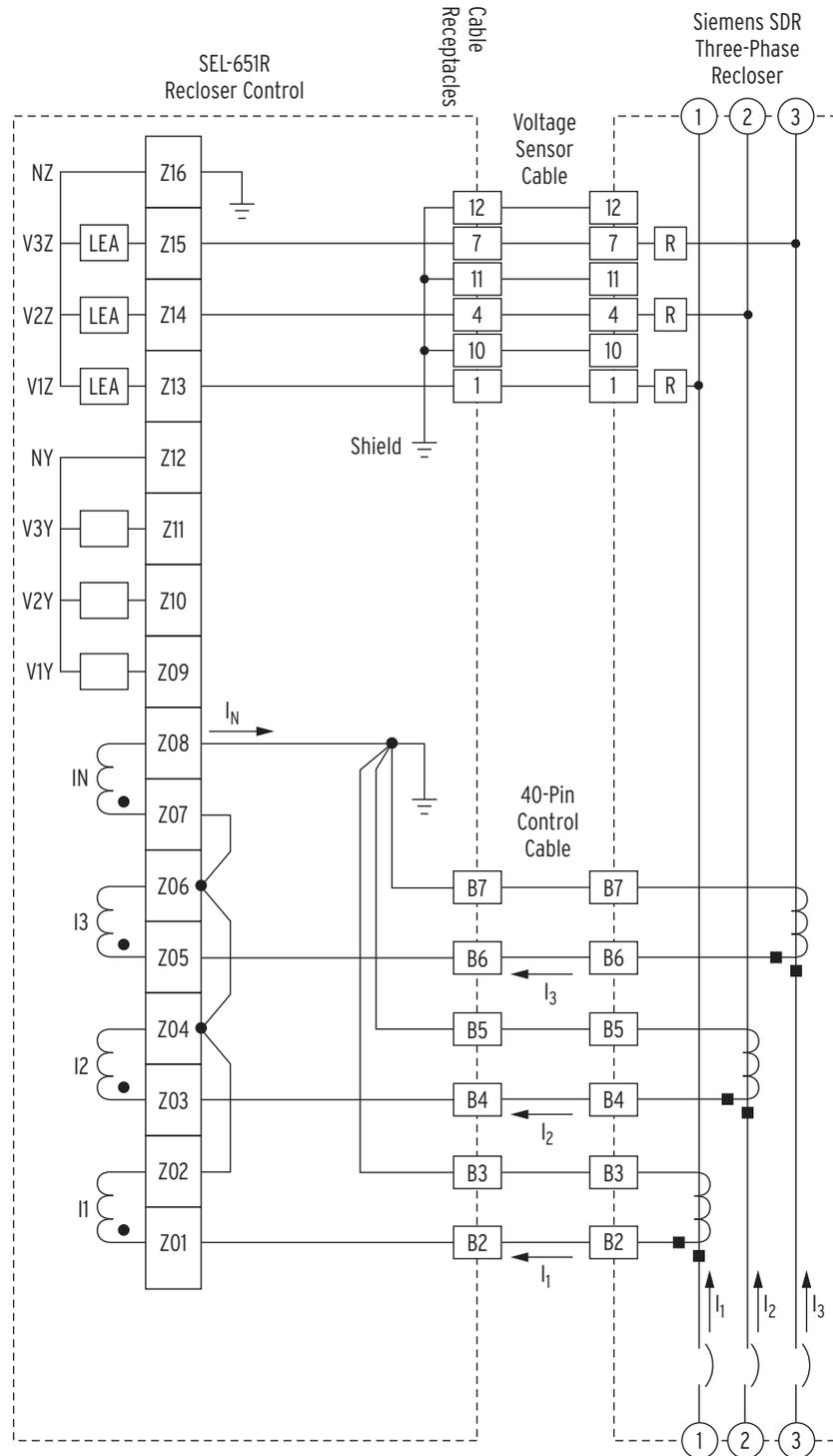
Figure 2.71   Current Connections and Polarity From Siemens SDR Three-Phase Recloser Primary to SEL-651R-2 Recloser Control Current Inputs

The Siemens SDR Triple-Single recloser in *Figure 2.72* has single-phase tripping/closing capability, while the Siemens SDR Three-Phase recloser in *Figure 2.73* does not. Thus, the Siemens SDR Triple-Single recloser in *Figure 2.72* has the additional complexity of per-phase tripping/closing and per-phase recloser status via the "CLOSE, S2 (52a)" contacts. The "OPEN, S1 (52b)" contacts in *Figure 2.72* are not used by the SEL-651R-2.

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RELAY WORD BIT TCCAP
Relay Word bit TCCAP indicates that the 155 Vdc voltage in Figure 2.72 and Figure 2.73 is present for recloser operations (TCCAP = logical 1). The 155 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8).

The operation of any individual lockout handle on the Siemens SDR Triple-Single recloser results in the opening/lockout of that phase (if not already open) and the assertion of the corresponding "LOCKOUT, S3 (69)" contact in *Figure 2.72* and the subsequent assertion of input IN204 in the SEL-651R-2.

The operation of the yellow lockout handle on the Siemens SDR Three-Phase recloser results in the opening/lockout of all three phases (if not already open) and the assertion of the "LOCKOUT, S3 (69)" contact in *Figure 2.73* and the subsequent assertion of input IN204 in the SEL-651R-2.

Input IN204 can be used in SELOGIC control equation settings to functionally keep the SEL-651R-2 in lockout (settings 79DTL__), block the issuing of a close (settings ULCL__), or (in the case of the Siemens SDR Triple-Single recloser) trip the other phases (settings TR__; see *Figure 5.2*).

In *Figure 2.72* and *Figure 2.73*, note that the trip and close FETs in the SEL-651R-2 are stacked on top of one another, between 155 Vdc power and ground, with a tap in the middle. For a given FET stack, both FETs can never be on at the same time or else there would be a direct short between the 155 Vdc power and ground. Interlocking logic prevents both FETs from being on at the same time.

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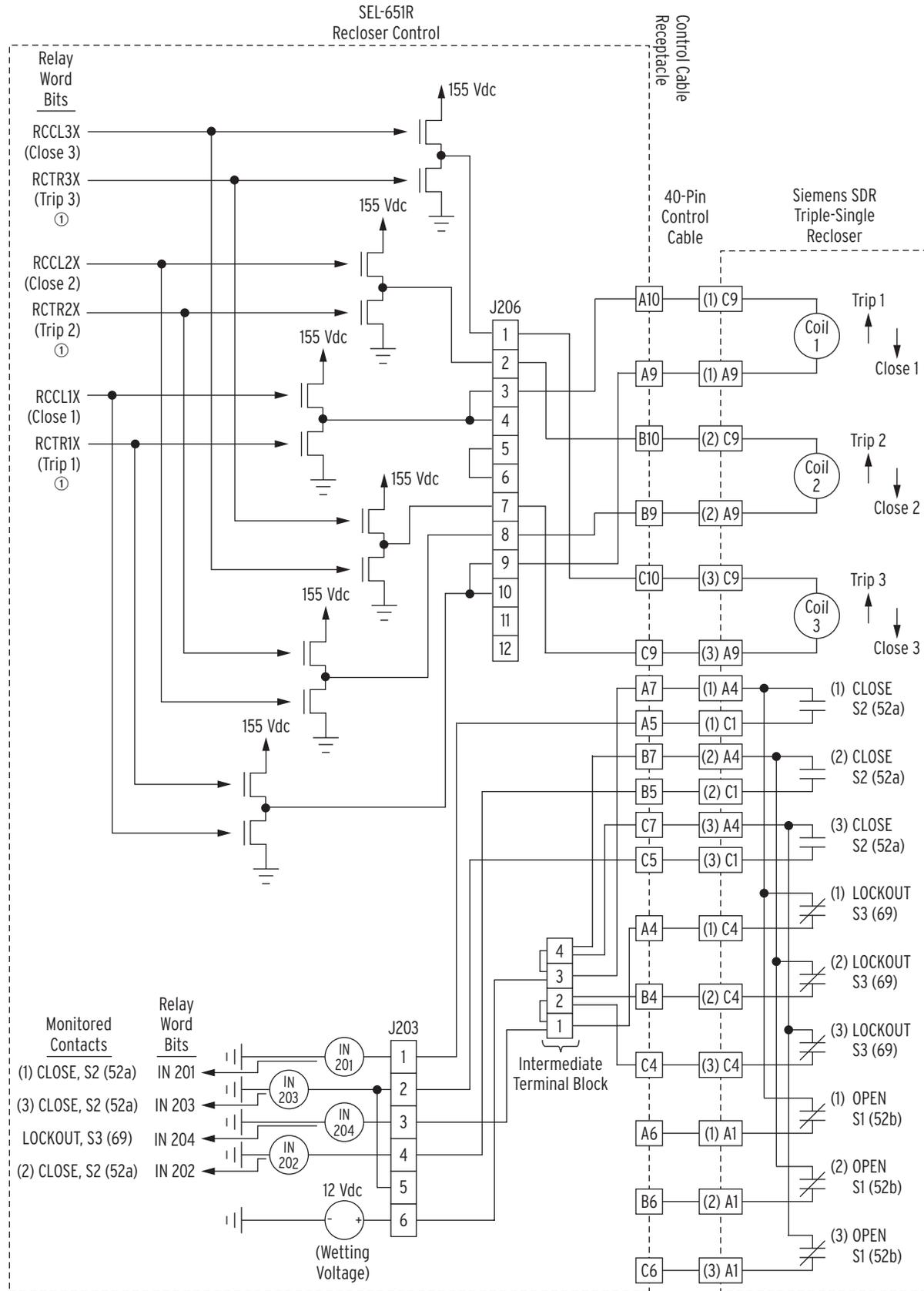
① See Figure 7.26

Figure 2.72   Trip/Close, Recloser Pole Status, and Lockout Handle Status Circuit Connections Between Siemens SDR Triple-Single Recloser and SEL-651R-2 Recloser Control

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SEL-651R
Recloser Control

Control Cable
Receptacle

Siemens SDR
Three-Phase
Recloser

Relay
Word
Bits

RCCL1X
(Close)

RCTR1X
(Trip)
①

155 Vdc

155 Vdc

J206

40-Pin
Control
Cable

C9   C9

A9   A9

Coil

Trip

Close

Relay
Word
Bits

IN205

IN206

Monitored
Contacts

CLOSE, S2 (52a)   IN 201

IN 203

LOCKOUT, S3 (69)   IN 204

OPEN, S1 (52b)   IN 202

J204

J203

12 Vdc

(Wetting
Voltage)

Intermediate
Terminal Block

A6   A6   CLOSE
             S2 (52a)
C1   C1

A4   A4   OPEN
             S1 (52b)
A1   A1

C6   C6   LOCKOUT
             S3 (69)
C4   C4

① See Figure 7.26

Figure 2.73   Trip/Close, Recloser Status, and Lockout Handle Status Circuit Connections Between Siemens SDR Three-Phase Recloser and SEL-651R-2 Recloser Control

Trace one of the trip paths in *Figure 2.72*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.26*) turns on the bottom trip FET (ground) connected to terminal J206-3 and the top trip FET (155 Vdc) connected to terminal J206-9. This wiring continues through control cable pins A10/(1)C9 and A9/(1)A9 to Coil 1 in the Siemens SDR Triple-Single recloser. The 155 Vdc across Coil 1 (bottom to top) causes the current to flow in the indicated trip direction.

Trace one of the close paths in *Figure 2.72*:

Relay Word Bit RCCL1X (Close 1; see *Figure 7.26*) turns on the top close FET (155 Vdc) connected to terminal J206-3 and the bottom close FET (ground) connected to terminal J206-9. This wiring continues

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through control cable pins A10/(1)C9 and A9/(1)A9 to Coil 1 in the Siemens SDR Triple-Single recloser. The 155 Vdc across Coil 1 (top to bottom) causes the current to flow in the indicated close direction.

The other trip/close circuits in *Figure 2.72* and *Figure 2.73* operate similarly.

Figure 2.74 and *Figure 2.75* show the routing of 120 Vac power through the 40-pin control cable to heaters in the Siemens SDR reclosers.
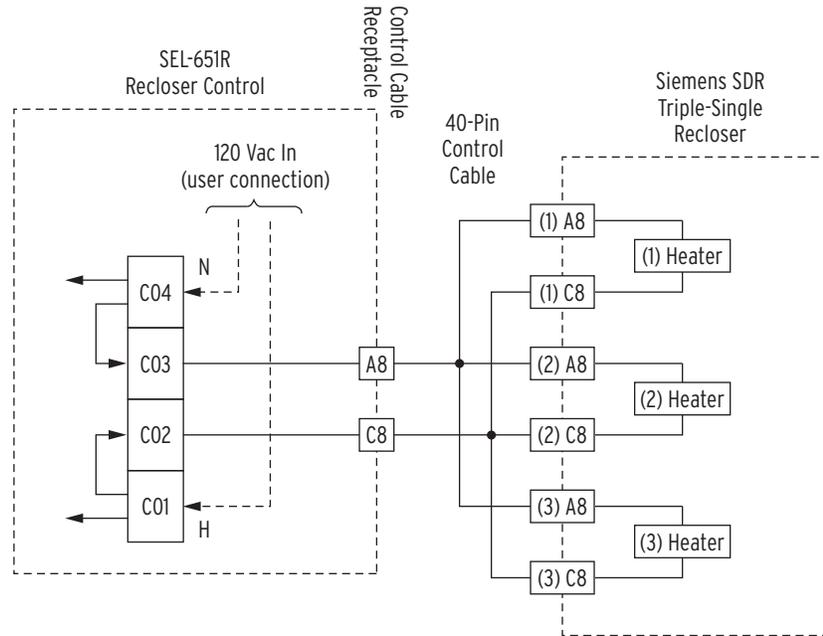
Figure 2.74   120 Vac Power Circuit Connections Between SEL-651R-2 Recloser Control and Siemens SDR Triple-Single Recloser
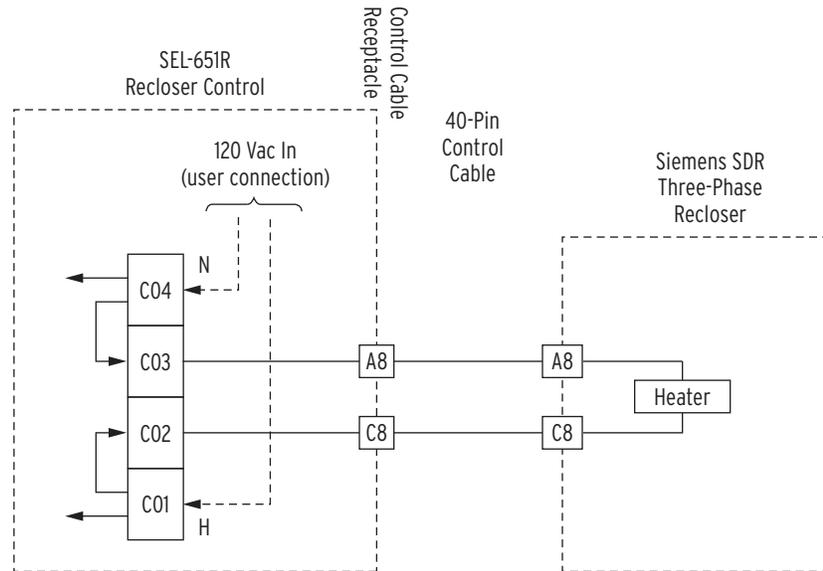
Figure 2.75   120 Vac Power Circuit Connections Between SEL-651R-2 Recloser Control and Siemens SDR Three-Phase Recloser

Multi-Recloser Interface

An SEL-651R-2 Recloser Control ordered with the Multi-Recloser Interface is compatible with the following single-phase trip/close capable reclosers:

➤ G&W Viper-ST, 32-pin and 42-pin

➤ G&W Viper-LT, 32-pin and 42-pin

➤ ABB Elastimold MVR

➤ Tavrida OSM Al_4

➤ ABB OVR/Gridshield, 32-pin and 42-pin

➤ Eaton NOVA NX-T

The interface uses a 42-pin control cable receptacle (see *Figure 2.16*, *Figure 2.25*, and *Figure 2.34*).

GLOBAL SETTING RECL_CFG
Global setting RECL_CFG is only available if the SEL-651R-2 Recloser Control is configured with a Multi-Recloser Interface. Otherwise, it is hidden.

The Multi-Recloser Interface makes the following settings and Relay Word bit additions:

➤ Introduces new, required Global setting RECL_CFG and associated Relay Word bits A1_CFG, A2_CFG, and A3_CFG (see *Table 2.4*)

➤ Automatically sets Global setting BKTYP:=1 [and hides the setting; see *Breaker/Recloser Type Setting (BKTYP) and Enable Single-Phase Breaker Setting (ESPB) on page 9.30*]

➤ Introduces new Relay Word bit 69_YH for 69 contacts operated by the yellow operating handles (see *Table 2.6*, *Figure 2.80*, and *69_YH Relay Word Bit for Multi-Recloser Interface on page 5.5*)

The Multi-Recloser Interface automatically sets the following SELOGIC settings (and hides them) according to Global setting IPCONN, as detailed in the corresponding tables:

➤ Breaker monitor initiate Global settings: BKMONA, BKMONB, and BKMONC (*Table 9.15*)

➤ Breaker/pole status (52a) settings: 52A_A, 52A_B, and 52A_C (*Table 2.7*)

➤ Trip output settings: RCTR1, RCTR2, and RCTR3 (*Table 9.19*; see also *Figure 7.26*)

➤ Close output settings: RCCL1, RCCL2, and RCCL3 (*Table 9.20*; see also *Figure 7.26*)

Table 2.4   Required Global Setting RECL_CFG and Corresponding Relay Word Bits and Recloser Configurations for the Multi-Recloser Interface (Sheet 1 of 2)

Recloser	Set Global Setting RECL_CFG :=	Resultant Relay Word Bit Logic State[a]	Source-Side Voltage Inputs[b]	Load-Side Voltage Inputs[b]	Adapter Cable Required?
G&W Viper-ST, 32-pin and Viper-LT, 32-pin	A1	A1_CFG= 1	V1Z, V2Z, V3Z	V1Y, V2Y, V3Y	yes [32-pin to 42-pin]
G&W Viper-ST, 42-pin and Viper-LT, 42-pin	A1	A1_CFG= 1	V1Z, V2Z, V3Z	V1Y, V2Y, V3Y	no
ABB Elastimold MVR	A1	A1_CFG= 1	V1Z, V2Z, V3Z	V1Y, V2Y, V3Y	yes [32-pin to 42-pin]
ABB OVR/Gridshield, 32-pin	A1	A1_CFG= 1	V1Z, V2Z, V3Z	V1Y, V2Y, V3Y	yes [32-pin to 42-pin]
ABB OVR/Gridshield, 42-pin	A1	A1_CFG= 1	V1Z, V2Z, V3Z	V1Y, V2Y, V3Y	no

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Table 2.4   Required Global Setting RECL_CFG and Corresponding Relay Word Bits and Recloser Configurations for the Multi-Recloser Interface (Sheet 2 of 2)

Recloser	Set Global Setting RECL_CFG :=	Resultant Relay Word Bit Logic State[a]	Source-Side Voltage Inputs[b]	Load-Side Voltage Inputs[b]	Adapter Cable Required?
Tavrida OSM Al_4	A2	A2_CFG= 1	V1Y, V2Y, V3Y	V1Z, V2Z, V3Z	no
Eaton NOVA NX-T	A3	A3_CFG= 1	V1Y, V2Y, V3Y	V1Z, V2Z, V3Z	yes [37-pin to 42-pin]

[a] Relay Word bits An_CFG (where n = 1–3) not shown are equal to 0.
[b] These are the nominal source and load sides, per recloser current transformer polarity convention (see Figure 2.76, Figure 2.77, and Figure 2.78).

Table 2.5   Default Global Setting CTPOL

Global Setting RECL_CFG :=	Default Global Setting CTPOL :=[a]
A1	POS
A2	POS
A3	NEG

[a] See Changing Global Setting RECL_CFG Changes the CTPOL Setting and the PTRY and PTRZ Settings for 8 Vac LEA Voltage Inputs on page 2.95.

Table 2.6   Breaker Auxiliary Contacts, Yellow Operating Handles, and Corresponding 69 Contacts for the Multi-Recloser Interface

Recloser	Set Global Setting RECL_CFG :=	Monitored per-phase breaker auxiliary contacts (Figure 2.80)[a]	Number of yellow operating handles on recloser	Monitored 69 contacts corresponding to yellow operating handles (Figure 2.80)	Yellow operating handle in lock-open position	
					Monitored 69 contacts status (Figure 2.80)	69 contacts status in trip/close circuit (Figure 2.79)[b]
G&W Viper-ST, 32-pin and Viper-LT, 32-pin	A1	52a1, 52a2, 52a3	Three (one per phase)	69_1, 69_2, 69_3	closed	open
G&W Viper-ST, 42-pin and Viper-LT, 42-pin	A1	52a1, 52a2, 52a3, 52b1, 52b2, 52b3	Three (one per phase)	69_1, 69_2, 69_3	closed	open
ABB Elastimold MVR	A1	52a1, 52a2, 52a3	Three (one per phase)	69_1, 69_2, 69_3	closed	open
ABB OVR/Grid-shield, 32-pin	A1	52a1, 52a2, 52a3	One (for all three phases)[c]	69_1, 69_2, 69_3	closed	open
ABB OVR/Grid-shield, 42-pin	A1	52a1, 52a2, 52a3, 52b1, 52b2, 52b3	One (for all three phases)[c]	69_1, 69_2, 69_3	closed	open
Tavrida OSM Al_4	A2	52b1, 52b2, 52b3	One (for all three phases)[d]	69	open	open
Eaton NOVA NX-T	A3	52a1, 52a2, 52a3, 52b1, 52b2, 52b3	Three (one per phase)	69_1, 69_2, 69_3	closed	open

[a] A recloser might have both 52a and 52b breaker auxiliary contacts available – the above listed breaker auxiliary contacts are those monitored for determining recloser pole status (see Table 2.7).
[b] The 69 contacts in the trip/close circuits in each recloser pole (see Figure 2.79) are not directly monitored, but provide the actual safety feature of disabling recloser operation (by open circuiting the trip/close circuit) when the corresponding yellow operating handle is pulled to the lock-open position. See 69_YH Relay Word Bit for Multi-Recloser Interface on page 5.5 for more information.
[c] The ABB Gridshield 3SP has three yellow operating handles (one per phase).
[d] Figure 2.80 shows three separate 69 contacts (69_1, 69_2, and 69_3), corresponding to per-phase yellow operating handles, for reclosers in Table 2.6 with Global setting RECL_CFG := A1 and RECL_CFG := A3. The reclosers in Table 2.6 with Global setting RECL_CFG:= A2 have only one yellow operating handle and a single corresponding 69 contact wired to input IN204 (not the three separate 69 contacts portrayed in Figure 2.80). See 69_YH Relay Word Bit for Multi-Recloser Interface on page 5.5 for more information.

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Table 2.7   Breaker/Pole Status (52A) Settings for the Multi-Recloser Interface

Global Setting	Breaker/pole status (52A) settings automatically set (and hidden) according to Global setting IPCONN		
IPCONN :=	52A_A :=	52A_B :=	52A_C :=
ABC	IN105 AND (A1_CFG OR A3_CFG) OR NOT IN201 AND A2_CFG	IN106 AND (A1_CFG OR A3_CFG) OR NOT IN202 AND A2_CFG	IN107 AND (A1_CFG OR A3_CFG) OR NOT IN203 AND A2_CFG
ACB	IN105 AND (A1_CFG OR A3_CFG) OR NOT IN201 AND A2_CFG	IN107 AND (A1_CFG OR A3_CFG) OR NOT IN203 AND A2_CFG	IN106 AND (A1_CFG OR A3_CFG) OR NOT IN202 AND A2_CFG
BAC	IN106 AND (A1_CFG OR A3_CFG) OR NOT IN202 AND A2_CFG	IN105 AND (A1_CFG OR A3_CFG) OR NOT IN201 AND A2_CFG	IN107 AND (A1_CFG OR A3_CFG) OR NOT IN203 AND A2_CFG
BCA	IN107 AND (A1_CFG OR A3_CFG) OR NOT IN203 AND A2_CFG	IN105 AND (A1_CFG OR A3_CFG) OR NOT IN201 AND A2_CFG	IN106 AND (A1_CFG OR A3_CFG) OR NOT IN202 AND A2_CFG
CAB	IN106 AND (A1_CFG OR A3_CFG) OR NOT IN202 AND A2_CFG	IN107 AND (A1_CFG OR A3_CFG) OR NOT IN203 AND A2_CFG	IN105 AND (A1_CFG OR A3_CFG) OR NOT IN201 AND A2_CFG
CBA	IN107 AND (A1_CFG OR A3_CFG) OR NOT IN203 AND A2_CFG	IN106 AND (A1_CFG OR A3_CFG) OR NOT IN202 AND A2_CFG	IN105 AND (A1_CFG OR A3_CFG) OR NOT IN201 AND A2_CFG

OTHER AUTOMATIC SETTINGS FOR MULTI-RECLOSER INTERFACE
See the settings in Table 9.15, Table 9.19, and Table 9.20.

Notice in *Table 2.7* that breaker/pole status (52A) settings effectively switch between monitoring 52a or 52b contacts (see *Figure 2.80*), depending on the logic state of Relay Word bits A1_CFG, A2_CFG, or A3_CFG, respectively (see *Table 2.4* and *Table 2.6*). In *Table 2.7*, 52b contact logic is inverted (e.g., "… OR NOT IN201 AND A2_CFG") to effective 52a contact logic.

Changing Global Setting RECL_CFG Changes the CTPOL Setting and the PTRY and PTRZ Settings for 8 Vac LEA Voltage Inputs

RE-EVALUATE PROTECTION SETTINGS AFTER CHANGING GLOBAL SETTING RECL_CFG
The adjacent discussion concerns potential transformer ratio settings automatically changing for particular circumstances when Global setting RECL_CFG is changed. But, all other settings are left unchanged. When a "Multi-Recloser Interface" SEL-651R-2 is changed to a different recloser, Global setting RECL_CFG could very well change (see Table 2.4). After such a setting change, protection-related settings (e.g., PT ratios, CT ratios, CT polarity, overcurrent, and voltage element pickups) should especially be re-evaluated.

When a "Multi-Recloser Interface" SEL-651R-2 is changed to a different recloser, Global setting RECL_CFG could very well change (see *Table 2.4*). If Global setting RECL_CFG changes, the following occur:

➤ The CTPOL setting automatically changes (see *Factory-Default Settings on page 9.61* and *Table 2.5*). You can change the CTPOL setting after the automatic change if desired.

➤ If there are 8 Vac LEA voltage inputs on the SEL-651R-2, the corresponding potential transformer ratio settings (PTRY and/or PTRZ) will change automatically. You can change these ratio settings after the automatic change if desired. See *Factory-Default Settings on page 9.61* for the required potential transformer ratio settings PTRY (for VY-terminal voltage inputs) and PTRZ (for Z-terminal voltage inputs) that allow the SEL-651R-2 to meter correctly with connection to these LEA voltage sensors. *Potential Transformer (PT) Ratios (Group Settings) on page 9.42* explains how such settings are derived.

Figure 2.76   Current Connections and Polarity for the Multi-Recloser Interface (Global Setting RECL_CFG := A1;
Optional Voltage Connections Also Shown)

NOTE: LEA sensor voltage dividers in some reclosers may be resistive instead of capacitive as depicted.

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Installation 2.97
Recloser Interface Connection Details (Voltage Cable Interface)

Figure 2.77   Current Connections and Polarity for the Multi-Recloser Interface (Global Setting RECL_CFG := A2; Optional Voltage Connections Also Shown)
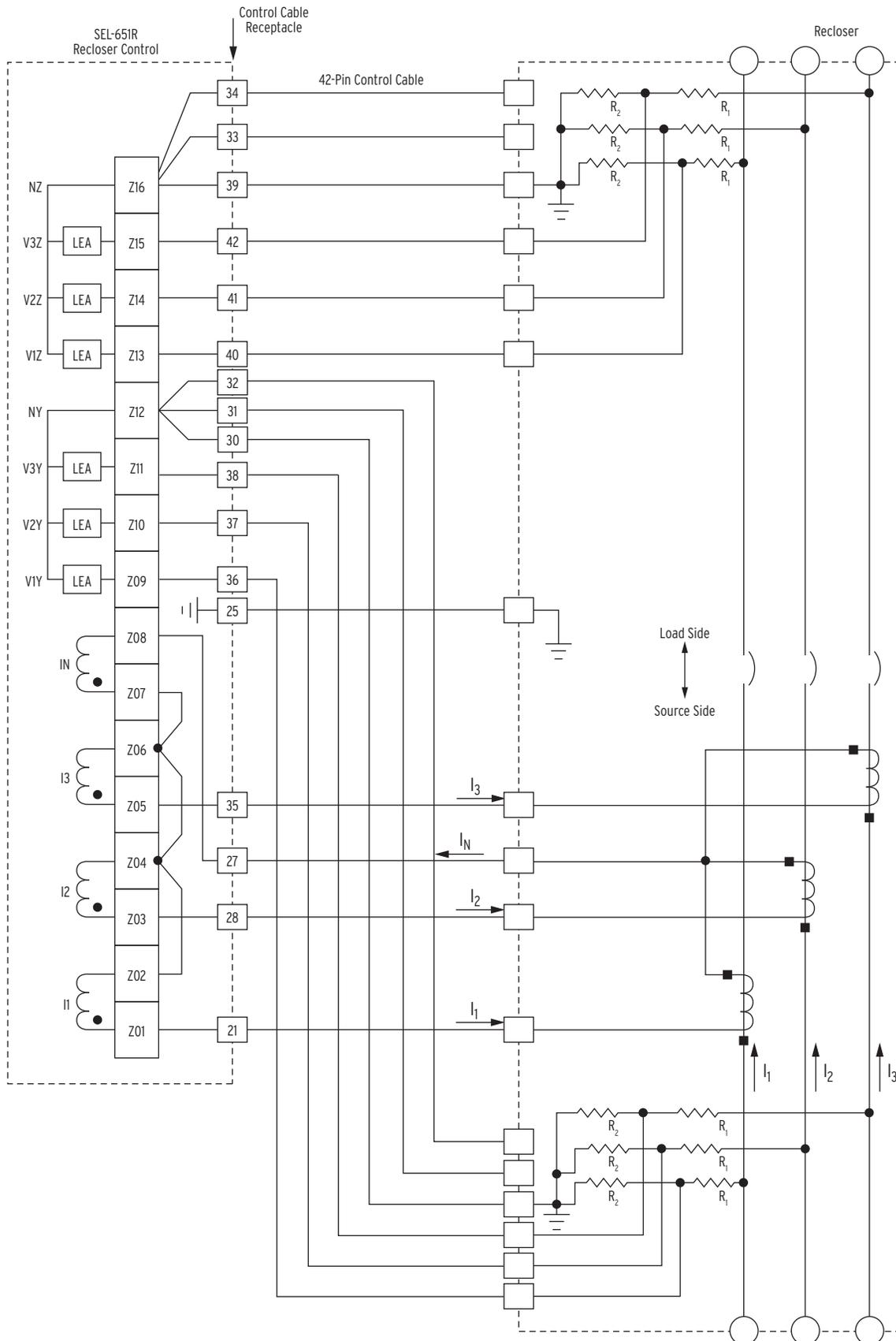
2.98 Installation
Recloser Interface Connection Details (Control Cable Interface)

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Figure 2.78   Current Connections and Polarity for the Multi-Recloser Interface (Global Setting RECL_CFG := A3; Optional Voltage Connections Also Shown)

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Installation 2.99
Recloser Interface Connection Details (Control Cable Interface)

SHIELDED CABLES

Shielded cables for LEA voltage inputs (see Figure 2.76 and Figure 2.77) come preinstalled on newer Multi-Recloser installations, with the shields effectively connected to ground at the bottom of the enclosure.

RELAY WORD BIT TCCAP

Relay Word bit TCCAP indicates that the 155 Vdc voltage in Figure 2.79 is present for recloser operations (TCCAP = logical 1). The 155 Vdc voltage comes into the relay module via connector J205 (CAPACITORS), from the trip/close capacitors in the power module (see Figure 2.2, Figure 2.5, Figure 2.7, and Figure 2.9). If there is a problem with this connection or otherwise in the power module, then Relay Word bit TCCAP = logical 0. Relay Word bit TCCAP is used in factory-default close logic settings (see Figure 6.4 and Figure 6.5) and reclose supervision settings (see Table 6.8).

In *Figure 2.76*, *Figure 2.77*, and *Figure 2.78*, notice that the phase current terminals are labeled I1, I2, and I3 (not IA, IB, and IC). A-B-C designations are given to the current channels with Global setting IPCONN. Current transformer polarity can effectively be changed with the Global CTPOL setting, which is helpful for designating such characteristics as forward or reverse power flow.

Figure 2.79 shows the SEL-651R-2 factory wiring for trip/close for the Multi-Recloser Interface. Each pole of the recloser has its own trip/close coil, trip for current flow in one direction, close for current flow in the other direction. This facilitates single-phase tripping/reclosing, although the SEL-651R-2 factory settings have the recloser operating in a three-phase trip/close mode setting (ESPB := N).

Note that the trip and close FETs in the SEL-651R-2 are stacked one atop another, between 155 Vdc power and ground, with a tap in the middle. For a given FET stack, both FETs can never be on at the same time or else there would be a direct short between the 155 Vdc power and ground. Interlocking logic prevents both FETs from being on at the same time.

Trace the trip path for Coil 1 in *Figure 2.79*:

Relay Word Bit RCTR1X (Trip 1; see *Figure 7.26*) turns on the bottom FET (ground) connected to terminal J206-3 and the top FET (155 Vdc) connected to terminal J206-9. This wiring goes through control cable Pins 2 and 3 to Coil 1. The 155 Vdc across Coil 1 (bottom to top) causes the current to flow in the indicated direction (Trip 1).

Trace the close path for Coil 1 in *Figure 2.79*:

Relay Word Bit RCCL1X (Close 1; see *Figure 7.26*) turns on the top FET (155 Vdc) connected to terminal J206-3 and the bottom FET (ground) connected to terminal J206-9. This wiring goes through control cable Pins 2 and 3 to Coil 1. The 155 Vdc across Coil 1 (top to bottom) causes the current to flow in the indicated direction (Close 1).

The other trip/close circuits in *Figure 2.79* operate similarly.

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Recloser Interface Connection Details (Control Cable Interface)

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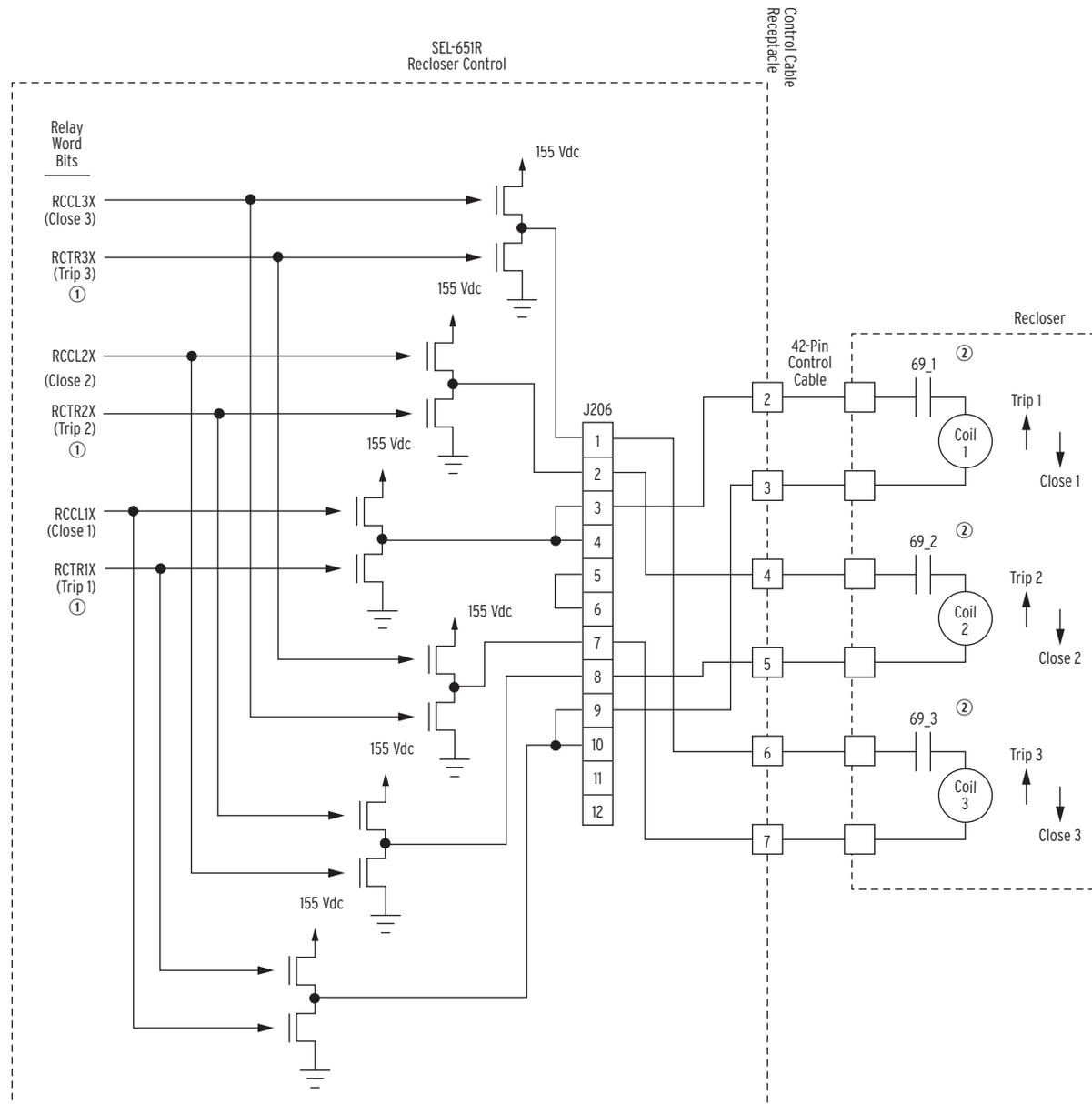
① See Figure 7.26.

② See footnote "ᵇ" accompanying Table 2.6.

Figure 2.79   Trip/Close Circuit Connections for the Multi-Recloser Interface

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Installation 2.101
Recloser Interface Connection Details (Voltage Cable Interface)
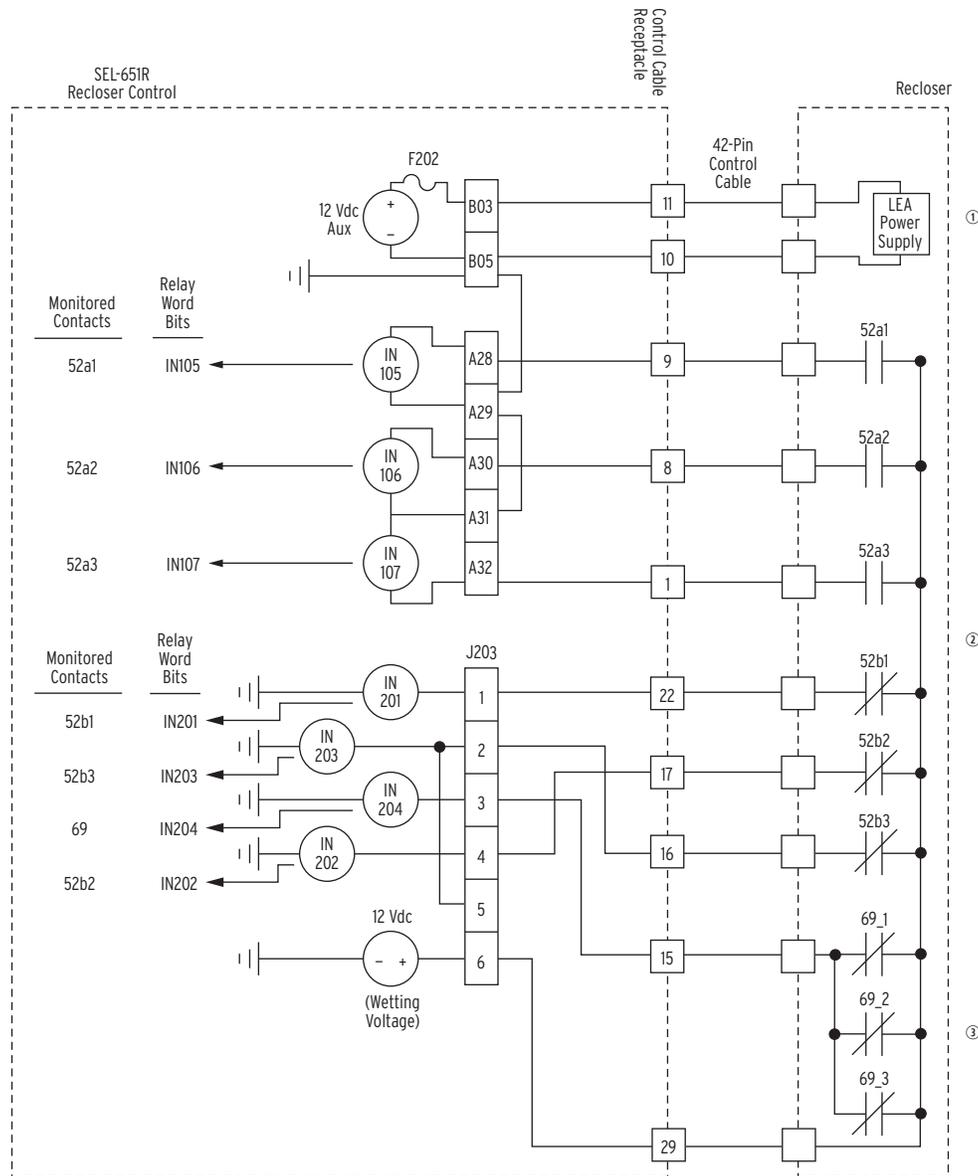
① Some recloser manufacturers have low-energy analog (LEA) voltage sensors that require 12 Vdc power.

② See footnote "a" accompanying Table 2.6.

③ See footnote "d" accompanying Table 2.6.

Figure 2.80 Recloser Pole Status and Yellow Operating Handle Circuit Connections for the Multi-Recloser Interface

Yellow Operating Handle Status

Relay Word bit 69_YH indicates that a yellow operating handle has been pulled to the lock-open position, for the Multi-Recloser Interface. See *69_YH Relay Word Bit for Multi-Recloser Interface on page 5.5* for more information.

➤ 69_YH asserted (yellow operating handle in lock-open position)

➤ 69_YH deasserted (yellow operating handle in reset position)

The following factory-default settings for the Multi-Recloser Interface provide a front-panel display indication of the yellow operating handle status (reset or lock-open), qualified for 5 cycles.

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Recloser Interface Connection Details (Control Cable Interface)

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SHO L Command

ESV := **3**

SV02PU := **5.00**

SV02DO := **60.00**

SV02 := **69_YH # QUALIFY YELLOW HANDLE OPERATION**

SHO F Command

EDP := **4**

DP03 := **SV02T,"YELLOW HANDLE","LOCK-OPEN","RESET"**

Disconnected Control Cable Alarm for the Multi-Recloser Interface

The disconnect control cable alarm for the Multi-Recloser Interface enables the front-panel display message. To be valid, the recloser is required to include both 52a and 52b breaker auxiliary contacts or the active Recloser Configuration setting is required to be A2. Review footnote "a" accompanying *Table 2.6*.

For Recloser Configuration A1 or A3, if both per-phase 52a and 52b breaker auxiliary contacts are connected in *Figure 2.80*, then a disconnected control cable can be detected. For a given phase, the 52a and 52b breaker auxiliary contacts should normally be of the opposite state. If they are both of the same state, then the control cable is disconnected or something is otherwise wrong with the connections in *Figure 2.80*.

For a recloser with Global setting RECL_CFG := A2, a de-energized input IN204 in *Figure 2.80* indicates that the yellow operating handle is in the lock-open position. Such yellow operating handle action (pulled from the reset to the lock-open position) causes all three recloser phases to open and remain open (see *69_YH Relay Word Bit for Multi-Recloser Interface on page 5.5*). The standard per-phase 52b breaker auxiliary contacts all go closed, energizing corresponding inputs IN201, IN202, and IN203. This is all normal, expected operation.

If the control cable is disconnected, then inputs IN201–IN204 in *Figure 2.80* are all de-energized. This indicates the following contradictory conditions for a recloser with Global setting RECL_CFG := A2:

➤ Recloser closed (52b inputs IN201, IN202, and IN203 all de-energized; see *Table 2.7*)

➤ Yellow operating handle in lock-open position (input IN204 de-energized)

Thus, the condition "recloser closed" and yellow operating handle "lock-open" is an abnormal/alarm condition and is indicative of a disconnected control cable or that something is otherwise wrong with the connections in *Figure 2.80* for a recloser with Global setting RECL_CFG := A2.

The following factory-default settings for the Multi-Recloser Interface provide a front-panel display indication of a disconnected control cable, qualified for 5 cycles.

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Installation 2.103
Recloser Interface Connection Details (Voltage Cable Interface)

SHO L Command

ESV := **3**

SV03PU := **5.00**

SV03DO := **60.00**

SV03 := **((NOT IN105 AND NOT IN201 OR NOT IN106 AND NOT IN202 OR NOT IN107
AND NOT IN203) AND (A1_CFG OR A3_CFG) OR 69_YH AND 52A3P AND A2_CFG)
QUALIFY DISCONNECTED CABLE**

SHO F Command

EDP := **4**

DP04 := **SV03T,,"CABLE DISCONNECTED"**

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Section 3

PC Software

Overview

This section contains the following subsections:

➤ *QuickSet Setup on page 3.3*

➤ *QuickSet Terminal on page 3.5*

➤ *QuickSet HMI on page 3.6*

➤ *QuickSet Settings on page 3.8*

➤ *QuickSet Event Analysis on page 3.18*

➤ *QuickSet Settings Database Management on page 3.21*

➤ *QuickSet Help on page 3.23*

SEL provides many PC software solutions (applications) that support SEL devices. These software solutions are listed in *Table 3.1*.

Table 3.1   SEL Software Solutions

Product Name	Description
SEL Compass	This application provides an interface for web-based notification of product updates and automatic software updating.
ACSELERATOR QuickSet SEL-5030 Software	QuickSet is a powerful setting, event analysis, and measurement tool that aids in applying and using the relay. See *Table 3.2* for information about the various QuickSet applications.
	This application allows you to customize relay settings to particular applications, instead of dealing with all settings in the device. These custom settings are stored in QuickSet Design Templates. You can lock settings to match your standards or lock and hide settings that are not used. This makes installation of a new device simple and helps ensure that new devices are applied according to your organization's standards.
ACSELERATOR Architect SEL-5032 Software	Use this application to design and commission SEL IEDs in IEC 61850 substations, create and map GOOSE messages, generate predefined reports, create and edit datasets, and read in SCD, ICD, and CID files.
ACSELERATOR TEAM SEL-5045 Software	The TEAM system provides custom data collection and movement of a wide variety of device information. The system provides tools for device communication, automatic collection of data, and creation of reports, warnings and alarms.
ACSELERATOR Analytic Assistant SEL-5601 Software	Converts SEL Compressed ASCII and COMTRADE event reports files to oscillography.
Cable Selector SEL-5801 Software	Selects the proper SEL cables for your application.

QuickSet is a powerful setting, event analysis, and measurement tool that aids in applying and using the relay. *Table 3.2* shows the suite of QuickSet applications. This section describes how to get started with QuickSet.

Table 3.2   QuickSet Applications

Application	Description
Terminal	Provides a direct connection to the SEL device. Use this feature to ensure proper communications and directly interface with the device.
HMI	Provides a summary view of device operation. Use this feature to simplify commissioning testing.
Rules Based Settings Editor	Provides online or offline device settings that include interdependency checks. Use this feature to create and manage settings for multiple devices in a database.
Event Analysis	Provides oscillography and other event analysis tools.
Settings Database Management	QuickSet uses a database to manage the settings of multiple devices.
Help	Provides general QuickSet and device-specific QuickSet context-sensitive help.

Obtaining QuickSet

QuickSet can be obtained from the Software Solutions area of the SEL website. To have the software automatically update as new relay drivers are released, download and install SEL Compass Software, then use Compass to download and install QuickSet. When you download QuickSet within Compass, you will be asked to select which relay drivers you want to include. Select drivers for all SEL relays that you may be required to set. If you need additional drivers at a later time, QuickSet provides an easy method to request new drivers and updates. See *Updating QuickSet on page 3.17*.

QuickSet is also available on CD upon request.

QuickSet Main Menu

The main menu provides the following options and submenu options. Selected submenu options are explained in detail in *Table 3.3*.

Table 3.3   QuickSet Submenu Options (Sheet 1 of 2)

File	➤ New—Create new settings for a connected device or offline ➤ Open—Open existing settings stored in a Relay Database (RDB) file ➤ Close—Close settings instance that is open in the QuickSet window ➤ Save/Save As—Save settings instance that is open in the QuickSet window to the active Relay Database (RDB) file ➤ Print Design—Print Design Template settings ➤ Print Device Settings—Print standard or custom settings reports ➤ Read—Read settings from a connected device and display the settings in the QuickSet window ➤ Send—Send settings instance that is open in the QuickSet window to a connected device ➤ Active Database—Change which Relay Database (RDB) file is used for the Open and Save/Save As commands. ➤ Database Manager—Open Database Manager to create a new Relay Database (RDB) file, copy settings within the active Relay Database (RDB) file, add descriptions to settings within the database, and copy and move settings between different databases. ➤ Exit—Quit the QuickSet software
Edit	➤ Copy—Copy settings from one Settings Group to another ➤ Search—Search for a text string within the settings instance ➤ Compare—Compare the settings instance that is open in the QuickSet window to another settings instance in the Relay Database file ➤ Merge—Merge the settings instance that is open in the QuickSet window with another settings instance in the Relay Database file ➤ Part Number—Change the current part number for the settings instance that is open in the QuickSet window

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Table 3.3 QuickSet Submenu Options (Sheet 2 of 2)

Communications	➤ Connect—Request QuickSet to attempt to connect to a device by using the current Connection Parameters ➤ Parameters—Modify the Communications Parameters, including connection type (Serial, Network, or Modem), PC port numbers, speed, and settings, device passwords, IP addresses, ports, and file transfer options, and modem phone numbers and speeds. ➤ Network Address Book—Select from a list of Ethernet-connected devices. Add or modify devices by specifying the Connection Name, IP Address, Telnet Port Number, User ID, and Password. ➤ Terminal—Open terminal window to issue ASCII commands directly to a connected relay. ➤ Logging—Initiate terminal logging to record terminal communications. View and clear the connection log.
Tools	➤ Settings—Convert settings between settings versions. Import and export settings from and to text files. ➤ HMI—Open HMI for connected device and manage custom HMI Device Overviews. ➤ Events—Collect event and view reports from connected devices. ➤ Options—Control QuickSet options, including Settings Prompt and Layout Options, Event Viewer, Terminal Options, and Advanced Communications Settings. ➤ Firmware Loader—Upgrade relay firmware. ➤ Commissioning Assistant, Motor Start Viewer, Chart Viewer—Plug-in applications that support commissioning and data analysis for specific relays.
Windows	➤ Cascade, Tile Horizontally, Tile Vertically—Arrange multiple QuickSet windows for easy viewing.
Help	➤ Access program and settings help ➤ Check for software updates.

QuickSet Setup

Follow the steps outlined in *Section 2: Installation* to prepare the relay for use. Perform the following steps to initiate communications:

Step 1. Connect the appropriate communications cable between the relay and the PC.

Step 2. Apply power to the relay.

Step 3. Start QuickSet.

When QuickSet starts, the initial screen presents the following icons:

New—Create new settings for a connected or unconnected device

Read—Read settings from a connected device

Open—Open previously saved settings

Communications Parameters—Configure serial and network connections

Manage Databases—Manage offline settings and databases

Update—Install and update QuickSet software and drivers

The functions represented by these six icons are also included in the menu items. See the discussions of the individual menu items in this section for a description of these functions.

3.4 | PC Software
QuickSet Setup

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Communications Parameters

QuickSet can communicate with a relay via any relay serial port set to SEL protocol, via the front-panel USB port, or via Ethernet. Perform the following steps to configure QuickSet to communicate with the relay.

Step 1. Select **Communications > Parameters** from the QuickSet main menu bar to open the **Communication Parameters** dialog box, or select **Communications Parameters** from the startup screen.

Step 2. Select the type of connection to be used: Serial, Network, or Modem. To use the relay front-panel USB port, select Serial. Communications parameters can be defined simultaneously for Serial, Network, and Modem connections. The connection to be used is selected in the **Active Connection Type** drop-down menu.

Step 3. Configure the PC port.

If **Serial** is selected as the connection type:

a. Select the port number of the PC from the Device drop-down box.

b. Select the Data Speed for the relay serial port, or select Auto detect to allow the software to automatically determine the Data Speed. The default Data Speed for the relay is 9600.

c. Select appropriate settings for Data Bits, Stop Bits, Parity, and RTS/CTS (Hardware Handshaking) according to the settings of relay serial port. Default settings are Data Bits = 8, Stop Bits = 1, Parity = N, and RTS/CTS = OFF.

d. Enter the relay Access Level One and Access Level Two passwords in the respective text boxes.

If **Network** is selected as the connection type:

a. Enter the IP address of the relay Ethernet port as the Host IP Address

b. Enter the Telnet port number

c. Select **Telnet** as the File Transfer Option.

d. Enter the relay Access Level One and Access Level Two passwords in the respective text boxes.

e. Use the **Save to Address Book** button to save the entered information with a Connection Name for later use.

f. Relay Ethernet port setting ETELNET must be set to Y.

If **Modem** is selected as the connection type:

a. Select the port number of the PC modem from the **Device** drop-down box.

b. Enter the phone number of the remote modem.

c. Select the data speed for the modem, or select Auto detect to allow the software to automatically determine the data speed.

d. Enter the relay Access Level One and Access Level Two passwords in the respective text boxes.

Step 4. Click **OK** when finished.

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QuickSet Terminal

Terminal Window

The terminal window is an ASCII interface with the relay. This is a basic terminal emulation with no file transfer capabilities. Many third-party terminal emulation programs are available with file transfer encoding schemes.

Open the terminal window by either clicking **Communication > Terminal**, clicking on the Terminal icon on the toolbar, or by pressing **<Ctrl+T>**.

Verify proper communications with the relay by opening a terminal window, pressing **<Enter>** a few times, and verifying that an = (equal) prompt is received, as shown in *Figure 3.1*. If a prompt is not received, verify proper setup.
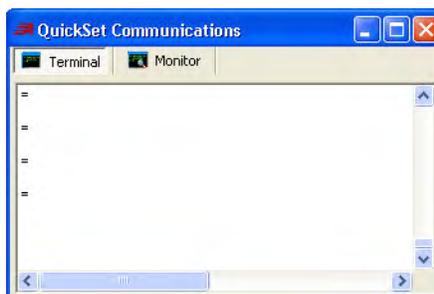
Figure 3.1   Terminal Prompt

Terminal Logging

If the **Terminal Logging** item in the **Communication** menu is selected, QuickSet records all communications between the relay and the PC in a log file.

Drivers

Enter Access Level 1 and issue the **STA** command to view the Firmware Identification (FID) string.

Locate and record the Z-number in the FID string. It will look similar to *Figure 3.2*. The first portion of the Z-number (Z001xxx, for example) determines the QuickSet relay settings driver version when you are creating or editing relay settings files. The later portion of the Z number (Zxxx001, for example) determines the HMI version number. These numbers are used by the applications to ensure proper interaction between the relay and QuickSet. The use of the driver version will be discussed in more detail later in this section.

Relay Settings Version Number

FID = SEL-651R-2-Rxxx-Vx-Z001001-Dxxxxxxxx

HMI Version Number
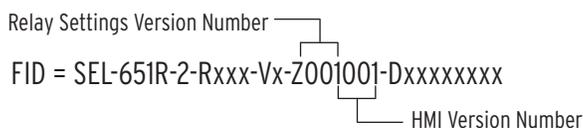
Figure 3.2   QuickSet Driver Information in the FID String

QuickSet reads the latter portion of the Z-number to determine the correct HMI to display when you select the menu. See *Open the QuickSet HMI on page 3.6* for instructions.

3.6 | PC Software
QuickSet HMI

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QuickSet HMI

Use the QuickSet HMI feature to view real-time relay information in a graphical format. Use the virtual relay front panel to read metering and targets (see *Figure 3.3*).
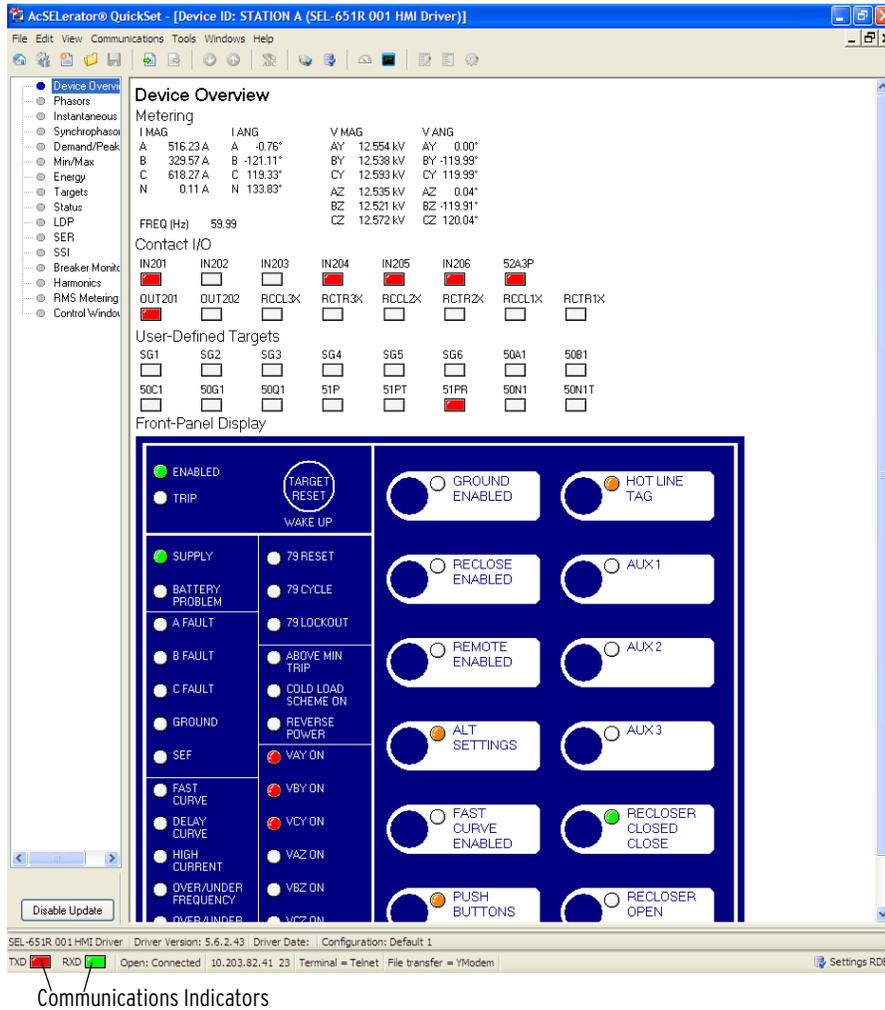
Figure 3.3   Virtual Relay Front Panel

Open the QuickSet HMI

Select **Tools > HMI > HMI** in the QuickSet menu bar. QuickSet opens the HMI window and downloads the interface data. The HMI can also be accessed by clicking the Human-Machine Interface icon (⌂).

QuickSet HMI Features

Table 3.4 lists the functions in the HMI tree view and a brief explanation of each function.

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Table 3.4   QuickSet HMI Tree View Functions

Function	Description
Device Overview	View general metering, selected targets, control input, control outputs, and the virtual front panel.
Phasors	A graphical and textual representation of phase and sequence voltages and currents.
Instantaneous	A table of instantaneous voltages, currents, powers, and frequency.
Synchrophasor	A table of synchrophasor data.
Demand/Peak	A table showing demand and peak demand values. This display also allows demand and peak demand values to be reset.
Min/Max	A table showing maximum/minimum metering quantities. This display also allows maximum/minimum metering quantities to be reset.
Energy	A table showing energy import/export. This display also allows energy values to be reset.
Targets	View Relay Word bits in a row/column format.
Status	A list of relay status conditions.
LDP	View load profile data.
SER	Sequential Events Recorder data listed oldest to newest, top to bottom. Set the range of SER records with the dialog boxes at the bottom of the display.
SSI	View voltage Sag, Swell, and Interruption data.
Breaker Monitor Data	A table showing the latest circuit breaker monitor data.
Control Window	Metering and records reset buttons, trip and close control, output pulsing, target reset, time and date set, group switch, and remote bit control.

The flashing LED representation in the lower left of the QuickSet window indicates an active data update via the communications channel (see *Figure 3.3*). Click **Disable Update** to suspend HMI use of the communications channel.

HMI Device Overview

Select the **Device Overview** branch to display an overview of the relay operation. This view includes a summary of information from many of the other HMI branches, including fundamental metering, contact input/output status, and front-panel LED status.

The **Device Overview** colors and text can be customized. White LED symbols indicate a deasserted condition and LED symbols with any other color indicate an asserted condition. Click an LED symbol to change its assert color. Double-click the LED label to change the label.

Double-click an operator control pushbutton label to change the label.

HMI Control Window

Select the **Control Window** branch to reset metering values, clear event records, trip and close reclosers/breakers, pulse output contacts, and set and clear remote bits (see *Figure 3.4*).

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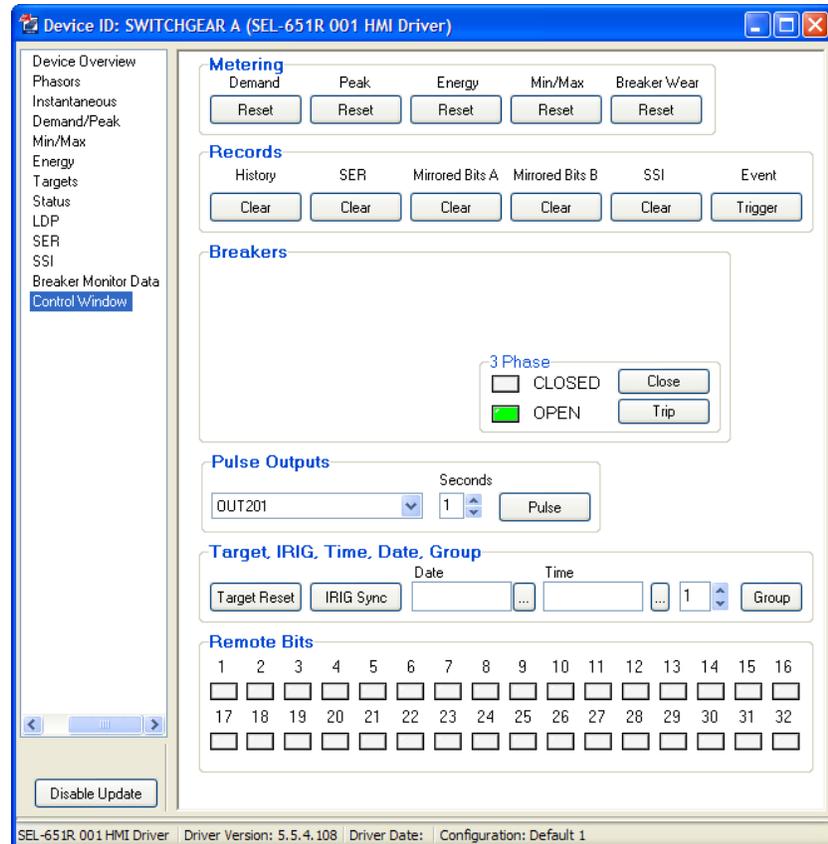
Figure 3.4   Control Window

Other HMI Branches

The remaining HMI branches display metering, targets, status, reporting, and monitoring information.

HMI Configurations

Customized **Device Overviews** can be saved as HMI Configurations. To save the current configuration, select **Tools > HMI > Save Configuration** to save the configuration under the current name, or **Tools > HMI > Save Configuration As** to specify a configuration name.

HMI configurations are identified by relay type and a configuration name. To use an existing configuration, select **Tools > HMI > Select Configuration**. To view available configurations, select **Tools > HMI > Manage Configurations**. To make an existing configuration the default configuration for a given relay type, select the configuration in the **Manage Configurations** window, select **Edit**, and select the **Default** check box.

QuickSet Settings

QuickSet provides the ability to create settings for many relays, or download and store settings from existing relays (see *Database Manager on page 3.22*). You can then modify and upload these settings from the settings library to a relay.

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PC Software 3.9
QuickSet Settings

SEL provides QuickSet for easier, more efficient configuration of relay settings. However, you do not have to use QuickSet to configure relays; you can use an ASCII terminal or a computer running terminal emulation software. QuickSet provides the advantages of rules-based settings checks, SELOGIC Control Equation Expression Builder, event analysis, and help.

Design Templates

A Design Template is a customized user interface for manipulating the settings of any SEL product supported by QuickSet. Design Templates are created with a licensed copy of QuickSet and are stored as relay files in a QuickSet relay database file (*.rdb). Various Design Templates are available from SEL. Contact SEL to inquire about licensing QuickSet to begin building your own custom templates.

The Design Template makes available only the settings that might need to be modified for a specific device application. These user-defined settings are referred to as design settings. They are the settings that are accessible through the Design Template view in QuickSet. The actual relay settings are calculated by rules inside the Design Template and are not visible in the Design Template view.

The SEL-651R-2 can store a QuickSet relay database (*.rdb) containing a Design Template. The Design Template is stored as a SWCFG.ZIP file separate from the relay settings (see *File > Read*). Although QuickSet automatically handles all communications necessary to manage Design Template storage, if the relay settings are modified using the SEL ASCII **SET** command or the relay front panel, it is possible for the current relay settings to be different from the settings stored within the Design Template file. *File > Read on page 3.11* discusses how QuickSet helps reconcile these differences.

The following discussion identifies two types of settings:

➤ Design Template settings are calculated and stored within a Design Template and can be stored as a file within the relay. The relay stores this file, but cannot read or change its content.

➤ Device settings are used for protection and control. These settings can be modified using QuickSet, SEL ASCII **SET** command, or the relay front panel.

File Menu

QuickSet uses a database to store and manage SEL device settings. Each unique device has its own record of settings. Use the **Settings** menu to create **New** settings, **Open** an existing record, or **Read** device settings.

File > New

To get started creating relay settings, select **File > New** from the main menu. QuickSet will display the **Settings Editor Section** window as shown in *Figure 3.5*. Select SEL-651 from the **Device Family** menu and the appropriate model (for example, SEL-651R-2) from the **Device Model** menu. Finally, select the Z number from the **Versions** menu. Click **OK**.

If the device family, device model, or version for the relay are not present, select **Install Devices** and follow the on-screen instructions to add the appropriate drivers.

3.10 | PC Software
QuickSet Settings

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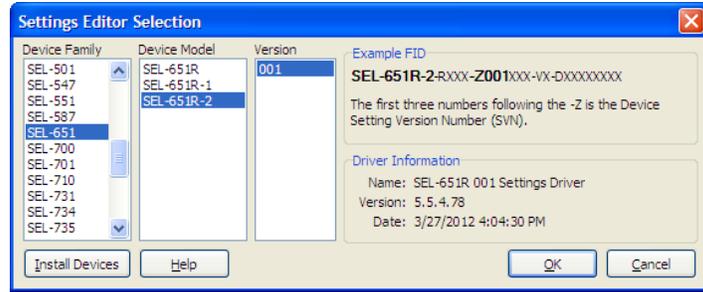
Figure 3.5   Settings Editor Selection

After the relay model and settings driver are selected, QuickSet presents the **Device Part Number** dialog box (shown in *Figure 3.6*). Use the drop-down menus within the **Device Part Number** dialog box to select the part number of the relay. Click **OK**.

View the bottom of the **Settings Editor** window to check the **Settings Driver** number (see *Figure 3.7*). Compare the QuickSet driver number and the first portion of the Z-number in the FID string. These numbers must match. QuickSet uses this first portion of the Z-number to determine the correct **Settings Editor** to display.
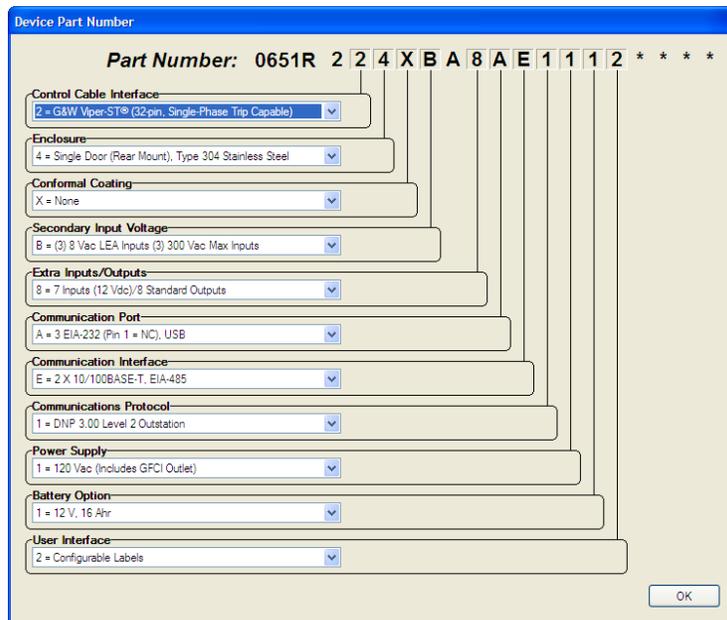
Figure 3.6   Setting the Part Number

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PC Software 3.11
QuickSet Settings
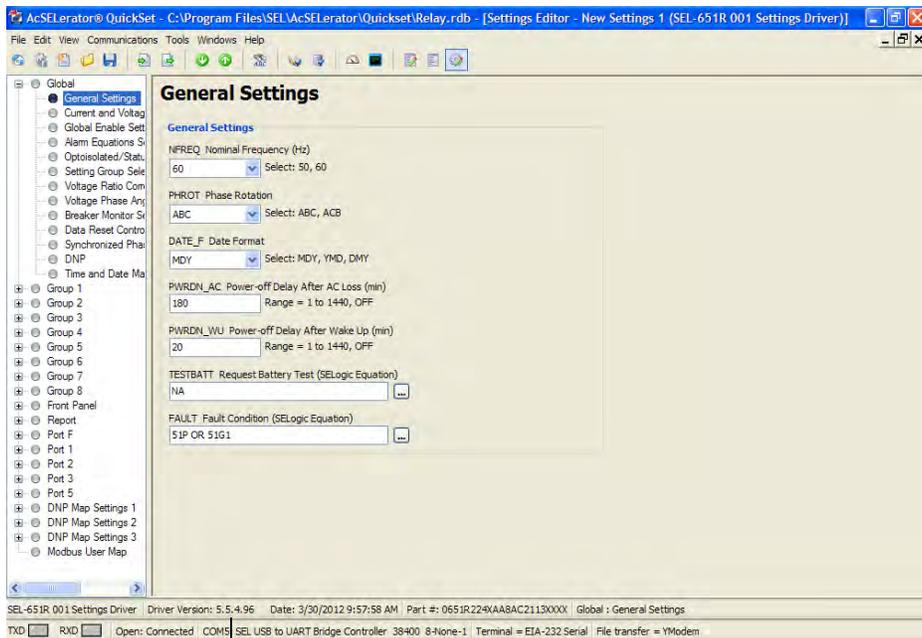
Relay Settings Driver Version Number

Figure 3.7   Settings Driver

File > Open

The **Open** menu item opens existing relay settings from the active database folder (see *Figure 3.8*). QuickSet displays the **Select Settings to Open** window and prompts for a device to load into the **Settings Editor**. The **Show settings with design templates** and **Show settings without design templates** check boxes allow settings with or without design templates to be included in or excluded from the **Select Settings to Open** window.
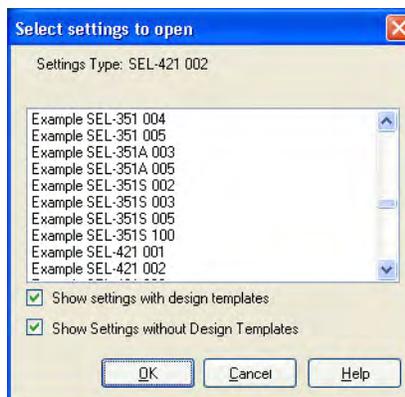
Figure 3.8   Opening Settings

Highlight the relay settings to be opened and click **OK**.

File > Read

When the **Read** menu item is selected, QuickSet displays the **Settings Group/Class Select** window (see *Figure 3.9*). Select the check boxes to specify which settings groups or classes are to be read from the connected device. Click **OK**. Note that settings not read from the device will be populated with the default settings. As QuickSet reads the device, a **Transfer Status** window appears.

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If the Settings Group/Class Select window is not displayed, select
Tools > Options and navigate to the **Settings** tab. When the **Specify Groups on Settings Read** check box is selected, the **Settings Group/Class Select** window is displayed for **File > Read**. When the **Specify Groups on Settings Read** check box is cleared (not selected), the **Settings Group/Class Select** window is not displayed, and the software reads all of the settings. Select whichever option you prefer.
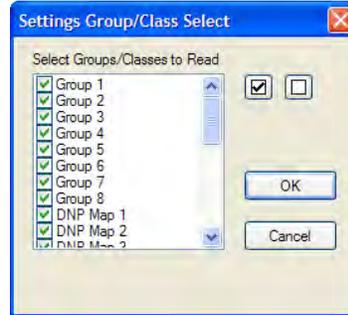
Figure 3.9 Reading Settings

If the software detects a Design Template stored as a SWCFG.ZIP file inside the relay, the **Settings Group/Class Select** window includes the option to Read Designer Template from Device.

Figure 3.10 Read Designer Template From Device

Selecting the **Read Designer Template from Device** check box instructs the software to read all the device settings and the Design Template. The software compares the device settings to the settings within the Design Template and offers to display the differences, if any. See *Figure 3.11*.
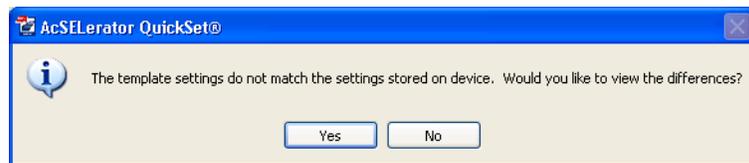
Figure 3.11 View Settings Differences

Clicking **Yes** causes the software to display a settings comparison, allowing you to verify the settings that may have changed since the Design Template was installed. In *Figure 3.12*, MAIN BREAKER 1 is the Relay Identifier (RID) from the Design Template, and TEST BREAKER 1 is the Relay Identifier read from the relay settings.

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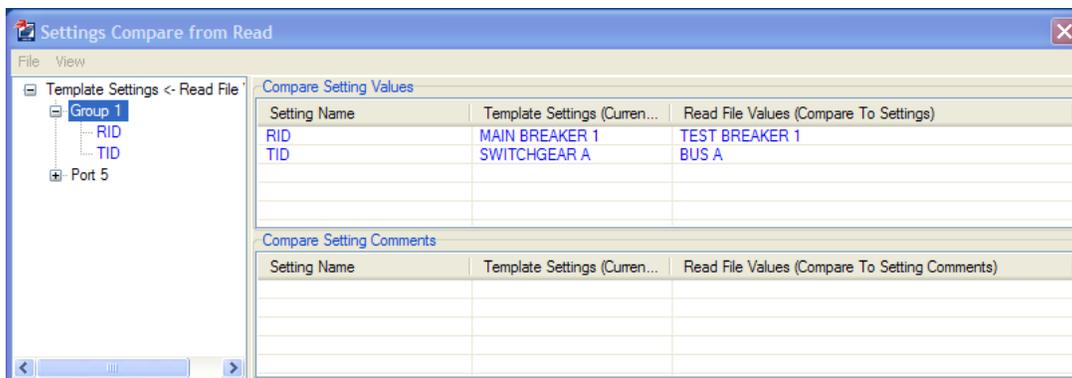
Figure 3.12   Settings Compare

In the Settings Compare view, select **File** to save the comparison to use later.

When you have evaluated all of the differences, close the settings comparison to view the Design Template. The relay settings are not displayed. Note in *Figure 3.13* that the Relay Identifier has the setting value MAIN BREAKER 1 from the Design Template, not TEST BREAKER 1 from the relay settings.
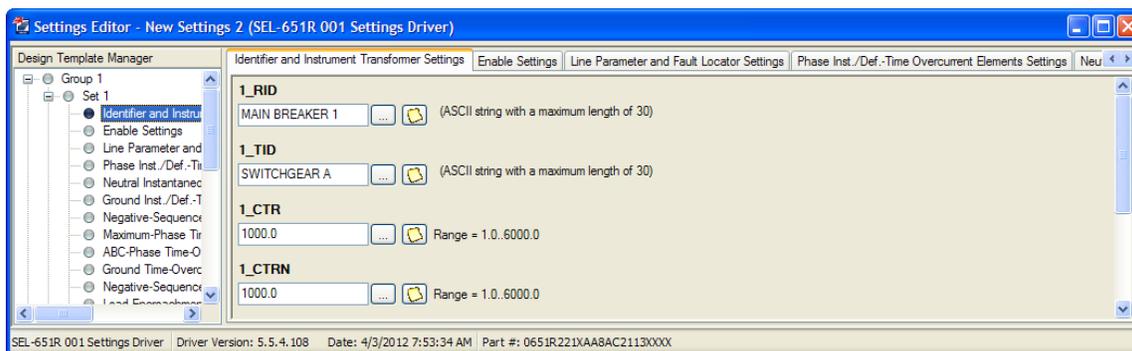
Figure 3.13   Design Template Settings Editor: New Settings

If you want to view the relay settings rather than the Device Template, leave the **Read Designer Template from Device** option unchecked.

Device Editor

The SEL-651R-2 settings structure makes setting the relay easy and efficient. Settings are grouped logically and relay elements that are not used in the selected protection scheme are not visible. For example, if settings are entered through use of the **SET** command and only three levels of a particular type of overcurrent protection are enabled, the Level 4, Level 5, and Level 6 overcurrent element settings do not appear on the communications terminal screen. Hiding unused elements and settings that are not enabled greatly simplifies the task of setting the relay.

QuickSet uses a similar method to focus attention on the active settings. Unused relay elements and inactive settings are dimmed (grayed) in the QuickSet menus.

QuickSet shows all of the settings categories in the settings tree view. The settings tree view does not change when settings categories are enabled or disabled. However, any disabled settings are dimmed. *Figure 3.14* illustrates this feature of QuickSet.

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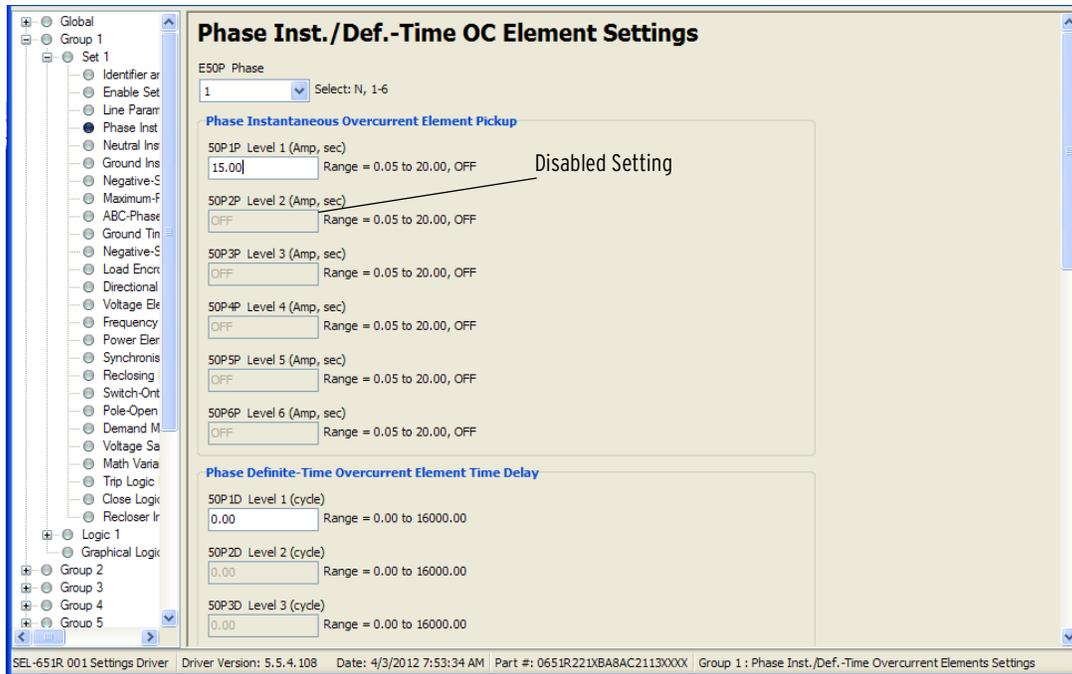
Figure 3.14   Settings Editor

Entering Settings

Click the arrows and the buttons in the Settings Tree View to expand and select the settings you want to change. Use the **Tab** key to navigate through the settings, or click on a setting.

To restore the previous value for a setting, right-click the setting and select **Previous Value**. To restore the factory-default setting value, right-click in the setting dialog box and select **Default Value**.

If you enter a setting that is out of range or has an error, QuickSet shows the error at the bottom of the **Settings Editor**. Double-click the error listing to go to the setting to enter a valid input.

Expression Builder

SELOGIC control equations are a powerful means for customizing relay operation. QuickSet simplifies this process with the Expression Builder, a rules-based editor for programming SELOGIC control equations. The Expression Builder organizes relay elements and SELOGIC control equation variables and focuses equation decision-making.

Access the Expression Builder

Click the ellipsis button to the right of each Logic setting in the Settings Editor window to start the Expression Builder (see *Figure 3.15*).
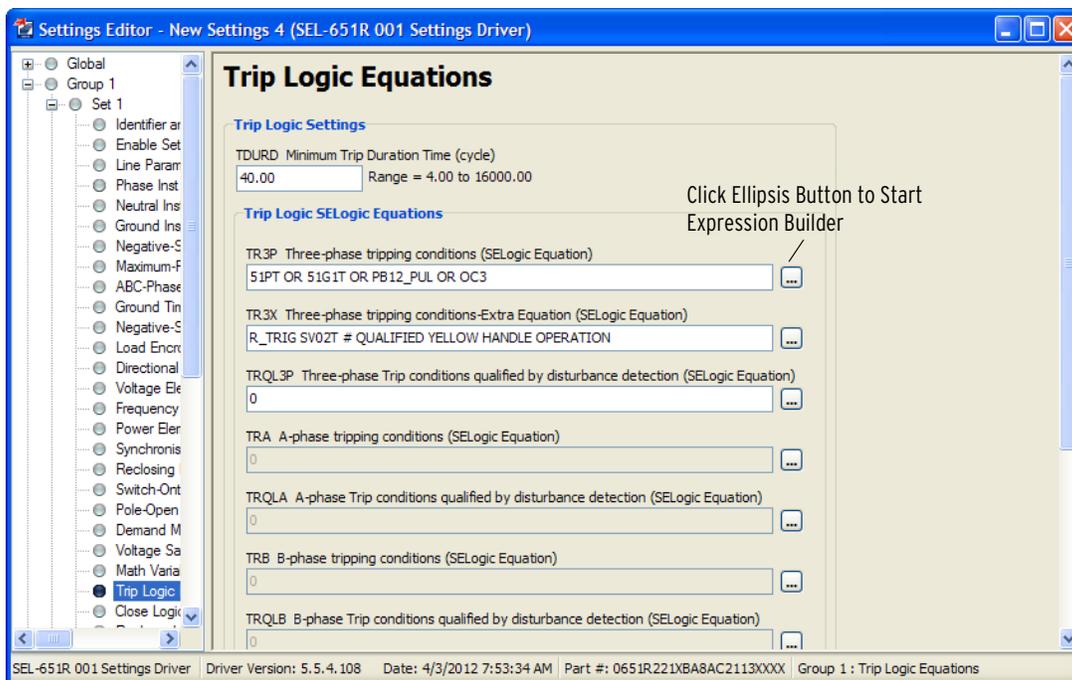
Figure 3.15   Settings Editor Window
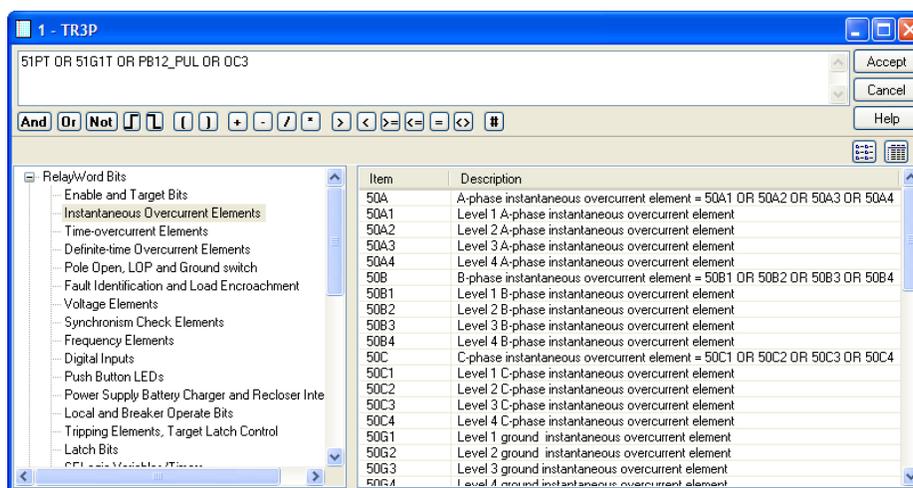
Figure 3.16   Expression Builder

Using the Expression Builder

SEL<small>OGIC</small> control equations can be built from a list of Relay Word bits. Select the + for Relay Word bits in the lower left box of the Expression Builder to expand the Relay Word bit tree. Relay Word bits are arranged in categories. Select the individual categories to view the associated Relay Word bits within the lower right box of the Expression Builder. Double-click a Relay Word bit to place it in the equation box at the top of the Expression Builder. Single-click the SEL<small>OGIC</small> operators below the equation box to add operators to the equation. Equations may also be typed directly in the equation box. Click **Accept** to exit the Expression Builder and save the equation, or **Cancel** to exit without saving.

For more information on programming SEL<small>OGIC</small> control equations, see *Section 7: SEL<small>OGIC</small> Control Equation Programming*.

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File > Save

Select **Save** or **Save As** from the **File** menu once settings are entered into QuickSet. This will help ensure the settings are not lost.

File > Send

Select the **Send** menu item from the **File** menu to send the settings to a connected device. Select which settings group you want to send and click **OK**.

If you are editing settings inside a Design Template, it is not necessary to select which settings groups to send. The creator of the Design Template specifies which groups to send and whether the Design Template itself is stored in the SWCFG.ZIP file. All settings groups are sent to the relay along with the Design Template. See *Figure 3.17*.
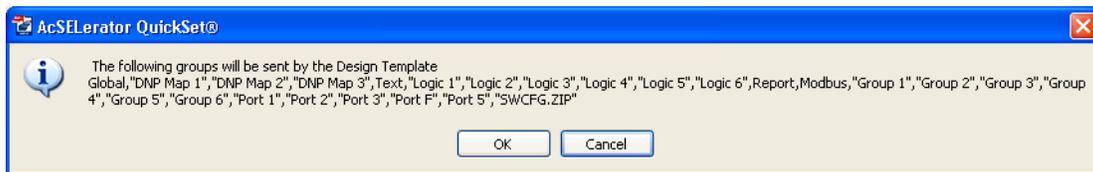
Figure 3.17   Settings Groups Sent by Design Template

Edit Menu

The Edit menu includes selections that aid in the creation and viewing of settings.

Edit > Copy

Use this menu item to copy group (set and logic) settings.

Edit > Search

Use this menu item to search for a particular setting or Relay Word bit.

Edit > Compare

Use this menu item to compare the open record with another record.

Edit > Merge

Use this menu item to merge the open record with another record.

Edit > Part Number

Use this menu item to change the part number if it was entered incorrectly during an earlier step.

Tools Menu

The **Tools** menu provides access to the HMI menus (see *QuickSet HMI on page 3.6*), event analysis tools (see *QuickSet Event Analysis on page 3.18*), and Settings Conversion and Options menus.

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Tools > Settings > Convert

Use the **Tools > Settings > Convert** menu item to convert from one settings version to another. Typically this utility is used to upgrade an existing settings file to a newer version when installed relays have a newer setting version number. In all settings conversions, settings that are new in the latest settings version are populated with the default settings unless otherwise indicated in this section. QuickSet provides a **Convert Settings** report that shows missed, changed, and invalid settings created as a result of the conversion. Review this report to determine whether changes are required.

Managing Relays Set With Design Templates

Design Templates allow you to create a custom view that shows only the settings necessary for a particular application. The relay settings are derived using rules inside the Design Template and may depend on other relay settings and design template settings. Because it is not possible to recalculate the design template settings from derived relay settings, SEL recommends the following process when setting relays through use of Design Templates:

1. When creating the Design Template, use the **Tools > Groups to Send** menu to configure the Design Template to Send Designer Template to Device. Select the **Tools > Design Template Options** menu and select the option **Allow switching to Settings Editor from Design**. In this way, settings which are not under the control of the Design Template equations can be revised within QuickSet.

2. Always use QuickSet to read settings from the relay and make settings changes.

    a. Always select the **Read Designer Template from Device** option when reading settings from the relay.

    b. Make settings changes within the Design Template read from the relay. Revise design template settings from within the Design Template view and select **View > Settings Editor** if it is necessary to revise settings which are not under the control of the Design Template equations.

    c. Use **File > Send** to send the settings and Design Template back to the relay.

    d. Save the Design Template as the record of the relay settings.

3. Avoid changing settings with the SEL ASCII **SET** command, relay front panel, or other software.

Updating QuickSet

The QuickSet software consists of a core application plus driver files for individual devices. As new device firmware versions are released, you may need to update QuickSet to add new driver files. This may be accomplished several ways:

➤ When **Enable Update Notifications** is checked in the **Tools > Options** menu of SEL Compass, the Compass software will automatically check for updates on a specified schedule and facilitate the update process.

➤ The **Update** icon on the QuickSet startup screen starts SEL Compass and checks for updates.

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➤ The **Install Devices** button on the Settings Editor Selection window starts SEL Compass and presents a menu of available drivers.

➤ **Check for updates** in the **Help** menu starts SEL Compass and checks for updates.

An Internet connection is required to add new drivers and to receive update notifications.

QuickSet Event Analysis

QuickSet has integrated analysis tools that help you retrieve information about protection system operations quickly and easily. Use the protection system event information that relays store to evaluate the performance of a protection system.

Event Waveforms

Relays record power system events for all trip situations and for other operating conditions programmed with SELOGIC control equations (see *Section 12: Analyzing Events*).

The relays provide three types of event data captures:

➤ event report oscillography that uses filtered sample per cycle data

➤ unfiltered (raw) data (compressed and COMTRADE format)

➤ high-impedance event report data

See *Section 12: Analyzing Events* for information on recording events. Use QuickSet to view event report oscillograms, phasor diagrams, harmonic analysis, and settings.

Read History

You can retrieve event files stored in the relay and transfer these files to a computer. To download event files from the relay, open the QuickSet **Tools > Events** menu on the QuickSet toolbar and click **Get Event Files**. The **Event History** dialog box will appear (similar to *Figure 3.18*).
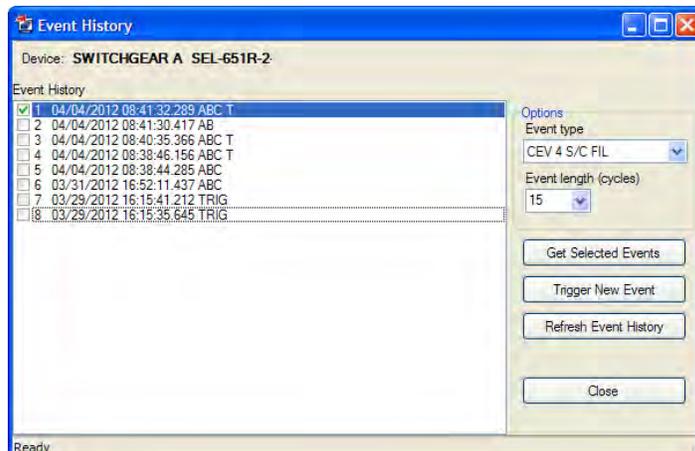
Figure 3.18   Retrieving an Event History

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Quickset Event Analysis

Get Event

Highlight the event you want to view and click the **Get Selected Event** button. The **Event Options** dialog box allows selection of Event Type and Event Length. When downloading is complete, QuickSet asks for a location to save the file on your computer. Select **Tools > Events> View Event Files** and select an event file to view events saved on your computer. QuickSet displays the Analytic Assistant dialog box and the event oscillogram (see *Figure 3.19* and *Figure 3.20*).

When viewing the event oscillogram, use keyboard function keys to measure the time of oscillogram occurrences. These function keys and related functions help in event analysis.

> ➤ **<F2>**: go to trigger

> ➤ **<F3>**: Cursor 1

> ➤ **<F4>**: Cursor 2

The display shows the time difference between Cursor 1 and Cursor 2.

To see high-accuracy time-stamp information on the event oscillogram, click the **Pref** button at the bottom of the oscillogram and select **Time** (under **Time Units, Starting/Ending Row**); click **OK**. Click on any point in a graph to observe the **Event Time** in microseconds of that point at the bottom of the oscillogram.

Figure 3.19   Event Waveform Window
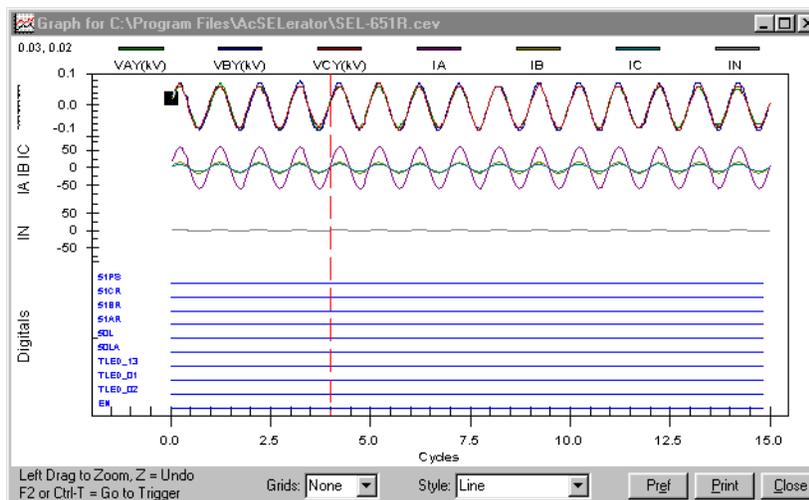
Figure 3.20   Sample Event Oscillogram

Other event displays are available through the **AcSELerator Analytic Assistant** dialog box. Select the **View** menu and click **Phasors**, as shown in *Figure 3.21*, to view a sample-by-sample phasor display. The phasor display should be similar to *Figure 3.22*.

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Figure 3.21   Retrieving Event Report Waveforms
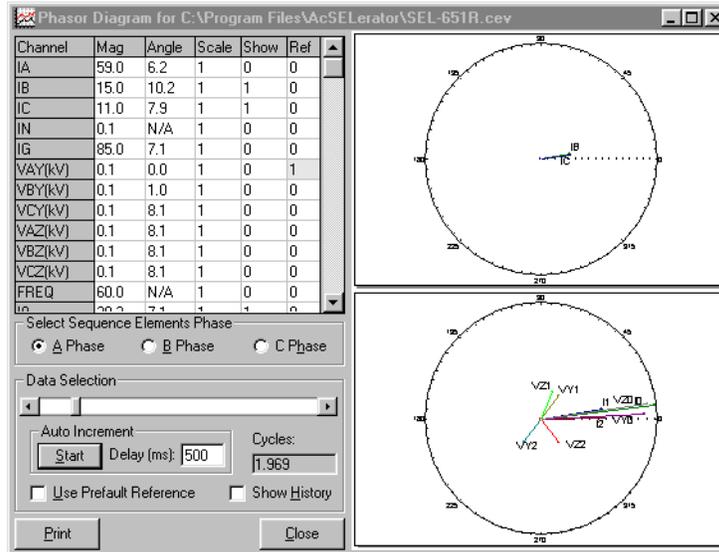
Figure 3.22   Sample Phasors Event Waveform Screen

QuickSet also presents a harmonic analysis of power system data for raw data event captures. From the **View** menu, click **Harmonic Analysis**. The window will be similar to *Figure 3.23*. On the left side of the **Harmonic Analysis** screen, select the relay voltage and current channels to monitor for harmonic content. Click the arrows of the **Data Scroll** box or the **# Cycles** box to change the data analysis range.
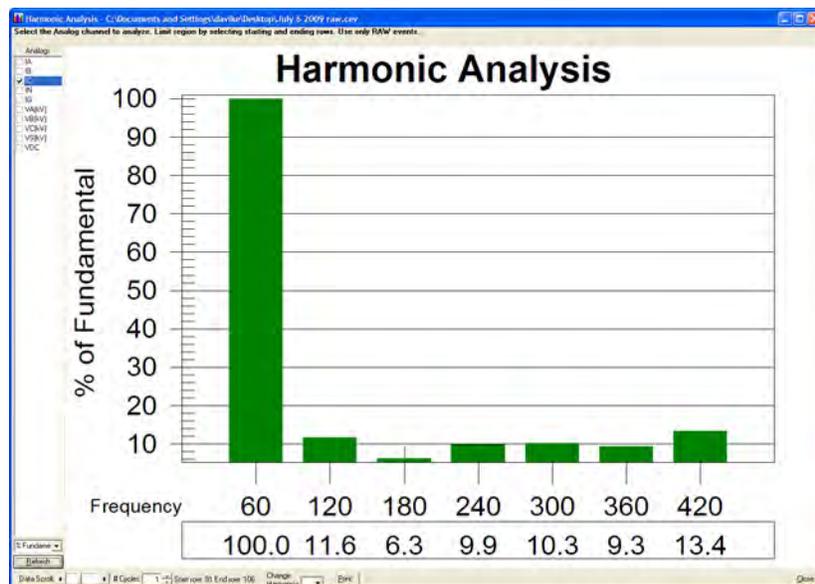
Figure 3.23   Sample Harmonic Analysis Event Waveform Screen

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QuickSet Settings Database Management

Click **Summary Data** on the **View** menu to see event summary information and to confirm that you are viewing the correct event. *Figure 3.24* shows a sample QuickSet **Event Report Summary** screen.
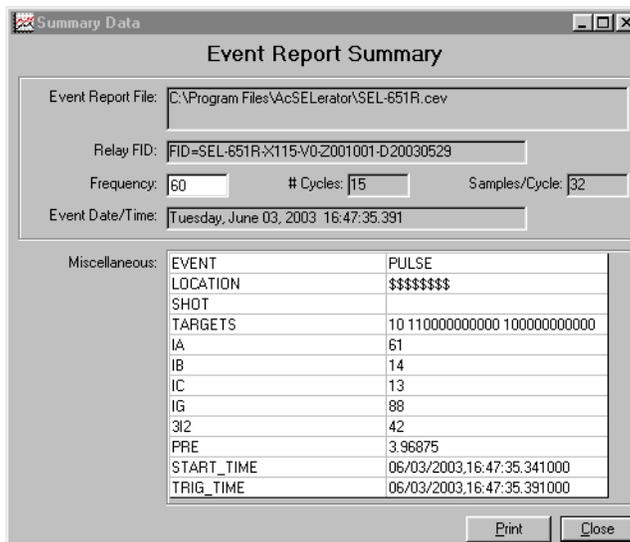
Figure 3.24   Sample Event Report Summary Screen

Click **Relay Settings** on the **View** menu to view the relay settings that were active at the time of the event. *Figure 3.25* shows a sample CEV-type event **Settings** screen.
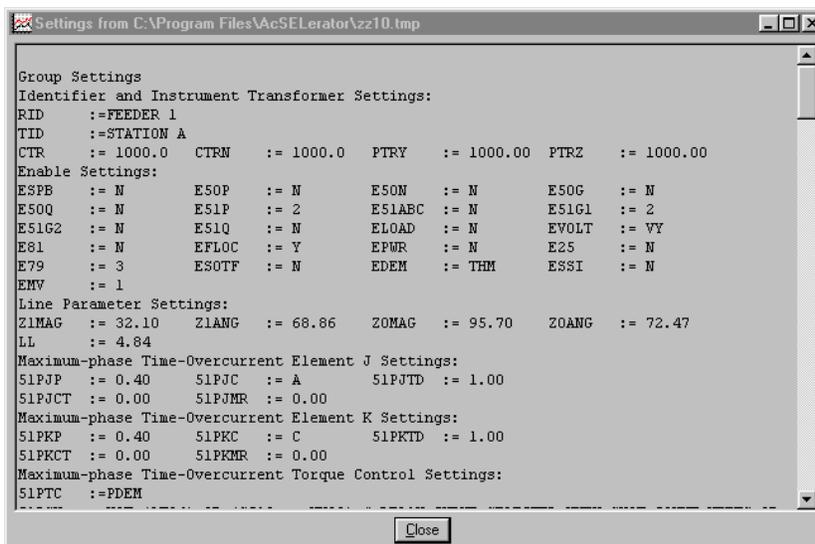
Figure 3.25   Sample Event Waveform Settings Screen

QuickSet Settings Database Management

QuickSet uses a database to save device settings. QuickSet contains sets of all settings files for each device specified in the **Database Manager**. Choose appropriate storage backup methods and a secure location for storing database files.

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Active Database

Change the active database to the one that needs to be modified by selecting **File > Active Database** on the main menu bar.

Database Manager

Select **File > Database Manager** on the main menu bar to create new databases and manage records within existing databases.

Settings Database

Open the **Database Manager** to access the database by clicking **File > Database Manager**. A dialog box similar to *Figure 3.26* appears.

The default database file already configured in QuickSet is **Relay.rdb**. Enter descriptions for the database and for the settings in the database in the **Database Description** and **Settings Description** dialog boxes.
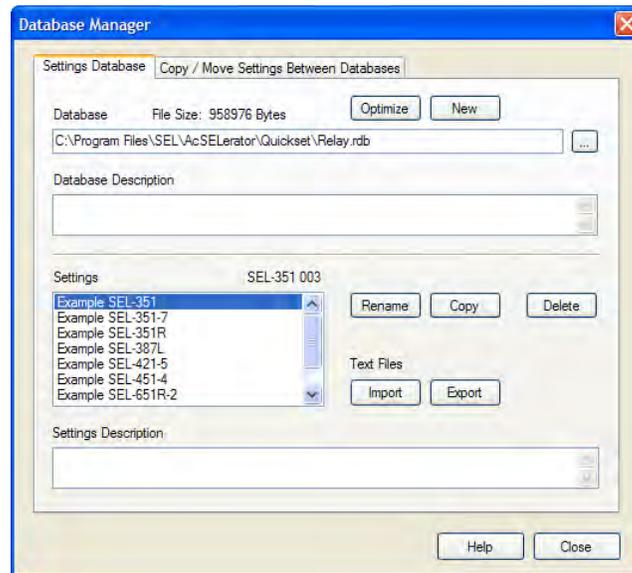
Figure 3.26   Database Manager

Highlight one of the devices listed in **Settings** and select the **Copy** button to create a new collection of settings. QuickSet prompts for a new name. Be sure to enter a new description in **Settings Description**.

Copy/Move Relays Between Databases

Select the **Copy/Move Settings Between Databases** tab to create multiple databases with the **Database Manager**; these databases are useful for grouping similar protection schemes or geographic areas. The dialog box is shown in *Figure 3.27*. Click the ellipsis button next to the **Database B** file extension window to open a database. Type a file name and click **Open**; for example, Relay2.rdb is the **B** database in *Figure 3.27*.

Highlight a setting in the **A** database, select **Copy** or **Move**, and click the ">" button to create a new setting in the **B** database. Reverse this process to take settings from the **B** database to the **A** database. **Copy** creates identical settings that appear in both databases. **Move** removes the settings from one database and places the settings in another database.

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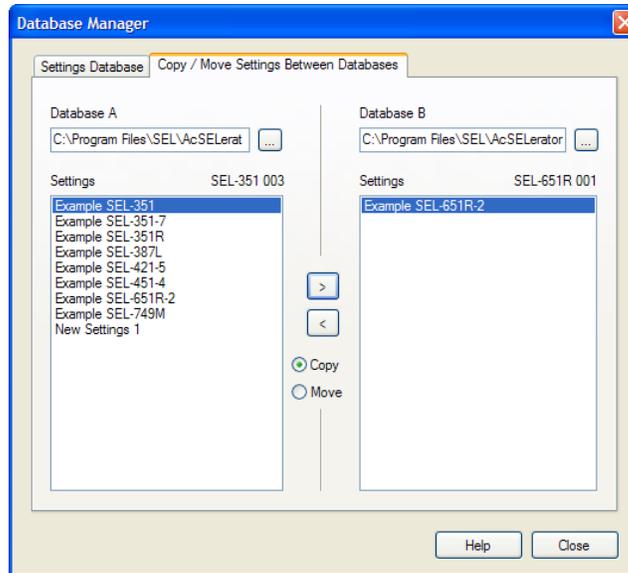
Figure 3.27   Database Manager Copy/Move

Create a New Database

To create and copy an existing database of settings to a new database, click **File > Database Manager** and select the **Copy / Move Relays Between Databases** tab on the **Database Manager** dialog box. QuickSet opens the last active database and assigns it as **Database A** (as shown in *Figure 3.27*).

Click the ellipsis button next to the **Database B** file extension window; QuickSet prompts you for a file location. Type a new database name, click the **Open** button, and answer **Yes**; the program creates a new empty database. Load settings into the new database as in **Copy / Move Relays Between Databases**.

QuickSet Help

Various forms of QuickSet help are available as shown in *Table 3.5*. Press **<F1>** to open a context-sensitive help file with the appropriate topic as the default. Other ways to access help are shown in *Table 3.5*.

Table 3.5   Help

Help	Description
General QuickSet	Select **Help > Contents** from the main menu bar.
HMI Application	Select **Help > HMI Help** from the main menu bar.
Relay Settings	Select **Help > Settings Help** from the from the main menu bar.
Database Manager	Select **Help** from the bottom of the **Database Manager** window.
Communications Parameters	Select **Help** from the bottom of the **Communications Parameters** window.

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Section 4

Protection Functions

Instantaneous/Definite-Time Overcurrent Elements

Phase Instantaneous/ Definite-Time Overcurrent Elements

Four levels of phase instantaneous/definite-time overcurrent elements are available. Two additional levels of phase instantaneous overcurrent elements (Levels 5 and 6) are also available. The different levels are enabled with the E50P enable setting, as shown in *Figure 4.1–Figure 4.7*.

Single-phase (50A, 50B, 50C) and maximum-phase (50P) elements are available. The single-phase elements operate on the individual phase currents, subject to assignment by setting IPCONN (see *Table 9.8*).

The single-phase and maximum-phase elements operate from the same pickup and time-delay settings. For example, if 50P1P is set to 6.00 A, both 50P1 and 50A1 will assert when the A-phase current exceeds 6.00 A, secondary.

These single-phase and maximum-phase elements are collectively referred to as Phase Instantaneous/Definite-Time Overcurrent Elements.

The single-phase and maximum-phase definite-time elements feature separate torque-control settings, as shown in *Figure 4.3–Figure 4.6*.

Settings Ranges

Setting range for pickup settings 50P1P–50P6P:

0.05–20.00 A secondary

Setting range for definite-time settings 50P1D–50P4D:

0.00–16000.00 cycles, in 0.25-cycle steps

Accuracy

See *Specifications on page 1.9*.

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Instantaneous/Definite-Time Overcurrent Elements

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NOTE: Do not use the 50P1–50P4 elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6). The 50P5 and 50P6 elements may also be used for load current detection.
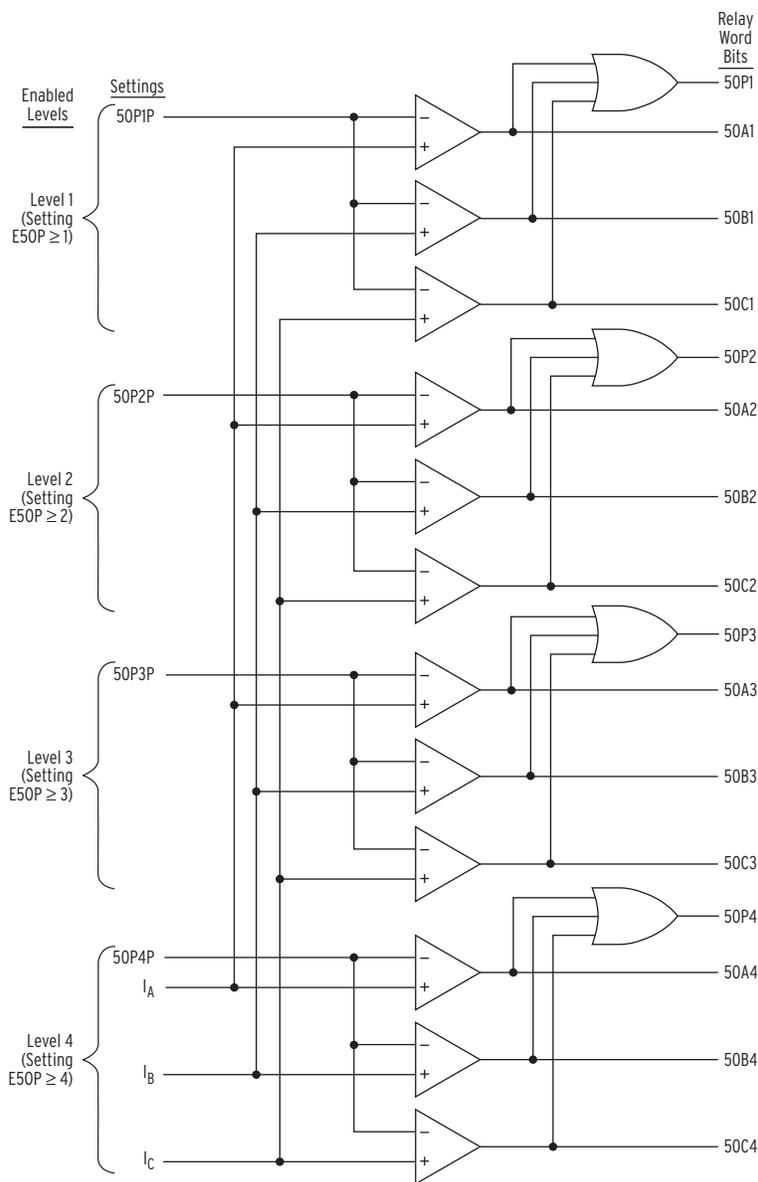
Figure 4.1   Levels 1–4 Phase Instantaneous Overcurrent Elements
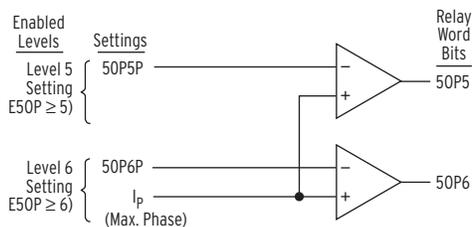
Figure 4.2   Levels 5–6 Phase Instantaneous Overcurrent Elements

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Instantaneous/Definite-Time Overcurrent Elements

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Pickup Operation

The phase instantaneous/definite-time overcurrent element logic begins with *Figure 4.1* and *Figure 4.2*. The pickup settings for each level (50P1P–50P6P) are compared to the magnitudes of the individual phase currents I_A, I_B, and I_C. The logic outputs in *Figure 4.1* and *Figure 4.2* are Relay Word bits and operate as follows (Level 1 example shown):

50A1 =	1 (logical 1)	if I_A > pickup setting 50P1P
	0 (logical 0)	if I_A ≤ pickup setting 50P1P
50B1 =	1 (logical 1)	if I_B > pickup setting 50P1P
	0 (logical 0)	if I_B ≤ pickup setting 50P1P
50C1 =	1 (logical 1)	if I_C > pickup setting 50P1P
	0 (logical 0)	if I_C ≤ pickup setting 50P1P
50P1 =	1 (logical 1)	if at least one of the Relay Word bits 50A1, 50B1, or 50C1 is asserted (e.g., 50B1 = 1)
	0 (logical 0)	if all three Relay Word bits 50A1, 50B1, and 50C1 are deasserted (50A1 = 0, 50B1 = 0, and 50C1 = 0)

Note that single-phase overcurrent elements are not available in Levels 5 and 6 (see *Figure 4.2*).

Ideally, set 50P1P > 50P2P > 50P3P > 50P4P so that definite-time overcurrent elements 50P1T–50P4T will display in an organized fashion in event reports (see *Figure 4.1* and *Table 12.5*).

NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 5OL element instead for load current detection (see Figure 5.6).
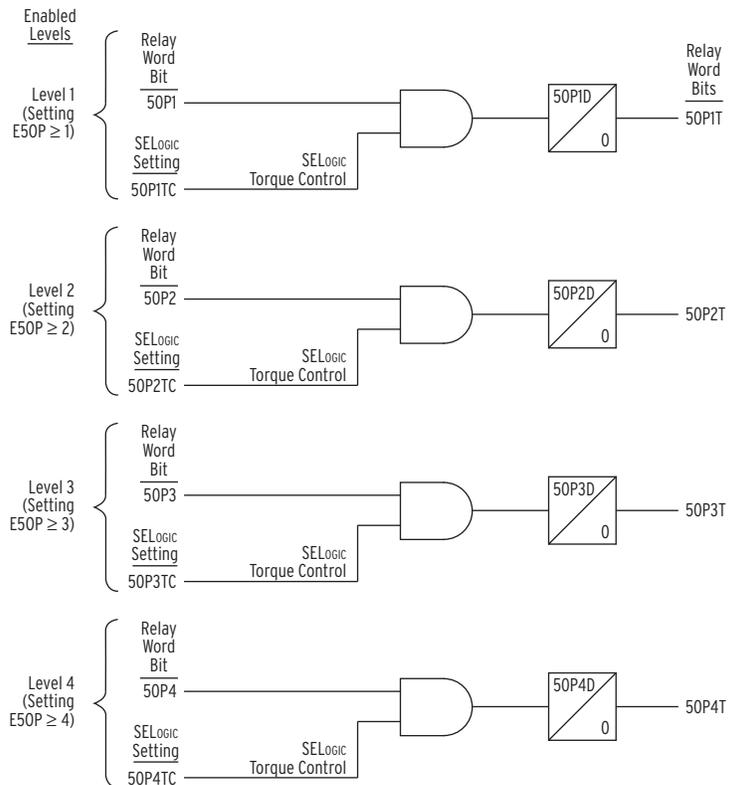
Figure 4.3   Levels 1-4 Phase Definite-Time Overcurrent Elements

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NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).
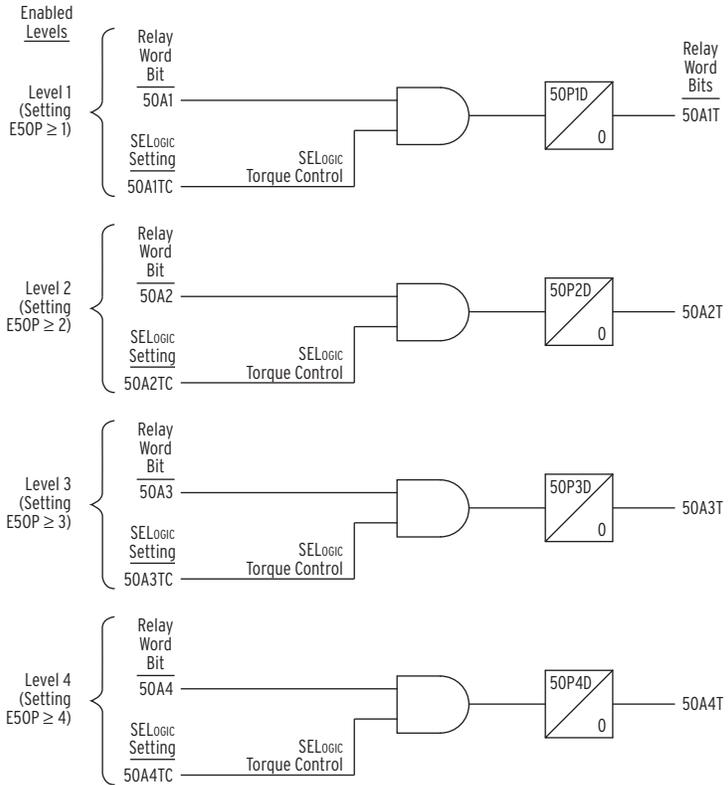
Figure 4.4   Levels 1–4 A-Phase Definite-Time Overcurrent Elements

NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).
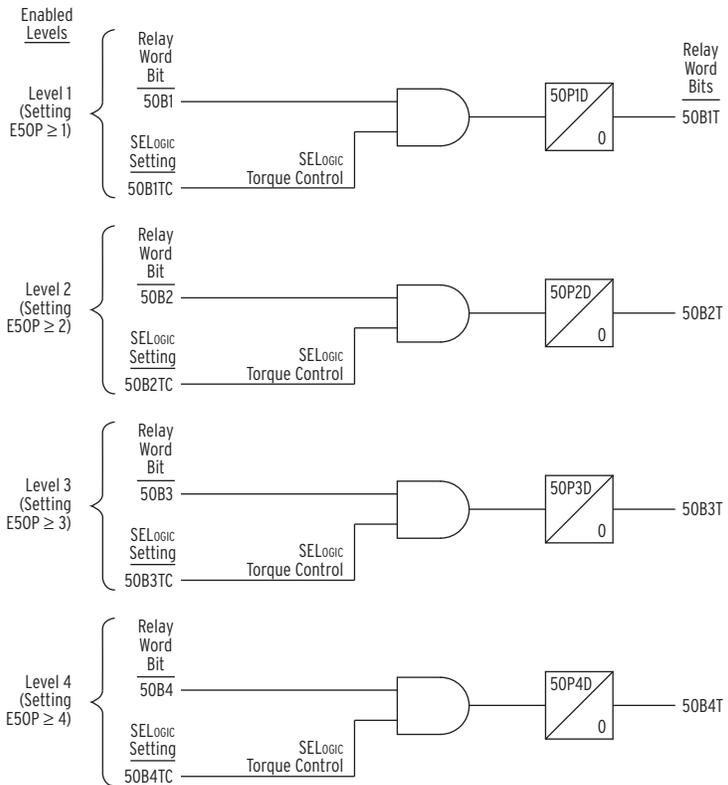
Figure 4.5   Levels 1–4 B-Phase Definite-Time Overcurrent Elements

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NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).
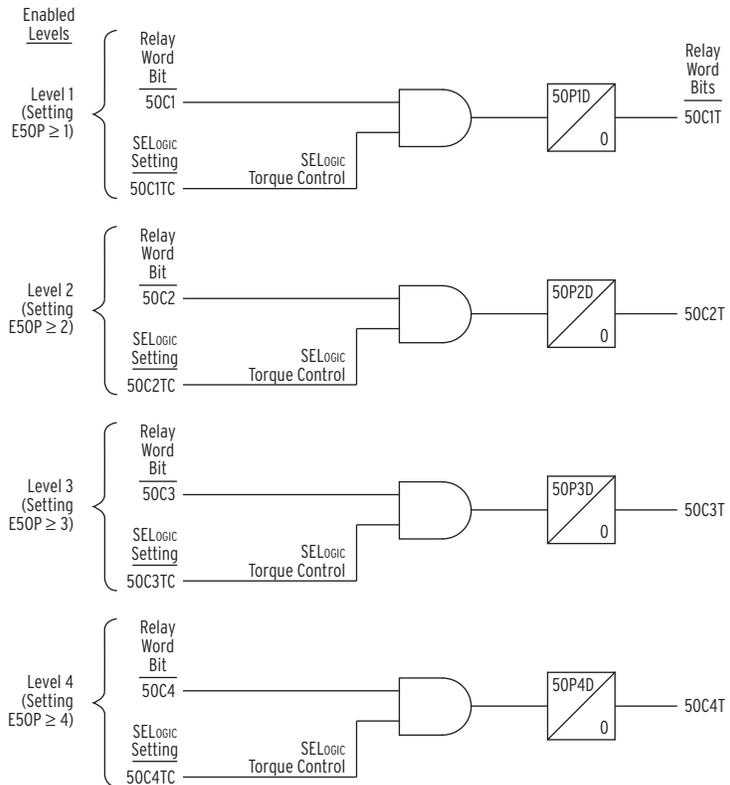
Figure 4.6   Levels 1–4 C-Phase Definite-Time Overcurrent Elements

Torque Control

Levels 1–4 have corresponding SELOGIC control equation torque-control settings:

➤ 50P1TC–50P4TC—Maximum-phase (*Figure 4.3*)

➤ 50A1TC–50A4TC—A-phase (*Figure 4.4*)

➤ 50B1TC–50B4TC—B-phase (*Figure 4.5*)

➤ 50C1TC–50C4TC—C-phase (*Figure 4.6*)

SELOGIC control equation torque-control settings cannot be set directly to logical 0. The following are torque-control setting examples for Level 1 phase definite-time overcurrent elements 50P1T and 50B1T.

50P1TC := **1**   Setting 50P1TC set directly to logical 1:

Phase definite-time overcurrent element 50P1T is enabled.

Note: In the SEL-651R-2 factory-default settings, the instantaneous/definite-time overcurrent element torque-control settings are set to logical 1. See *Factory-Default Settings on page 9.61*.

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50B1TC := **IN105**   Input IN105 deasserted (50B1TC := IN105 = logical 0):

> Then B-phase definite-time overcurrent element 50B1T is defeated and nonoperational, regardless of any other setting.

Input IN105 asserted (50B1TC := IN105 = logical 1):

> B-phase definite-time overcurrent element 50B1T is enabled.

Combined Single-Phase Instantaneous Overcurrent Elements

The single-phase instantaneous overcurrent element Relay Word bit outputs in *Figure 4.1* are combined together in *Figure 4.7* on a per-phase basis, producing Relay Word bit outputs 50A, 50B, and 50C.

Relay Word bits 50A, 50B, and 50C can be used to indicate the presence or absence of current in a particular phase.
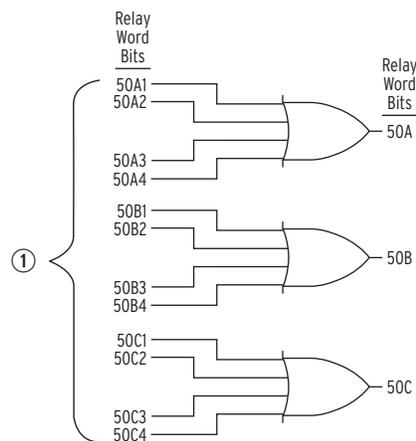
① From Figure 4.1.

Figure 4.7   Combined Single-Phase Instantaneous Overcurrent Elements

Pickup and Reset Time Curves

NOTE: The pickup time curve in Figure 4.8 is not valid for conditions with a saturated CT, where the resultant current to the relay is nonsinusoidal.

Figure 4.8 and *Figure 4.9* show pickup and reset time curves applicable to all instantaneous overcurrent elements in the SEL-651R-2 (60 Hz or 50 Hz systems). These times do not include output operating time and, thus, are accurate for determining element operation time for use in internal SELOGIC control equations.

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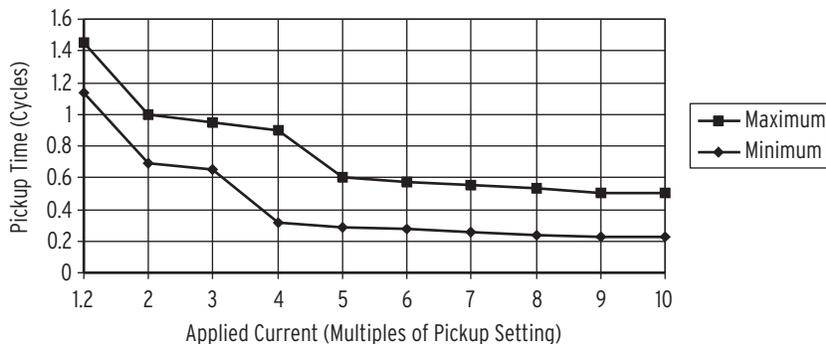
Figure 4.8 SEL-651R-2 Instantaneous Overcurrent Element Pickup Time Curve
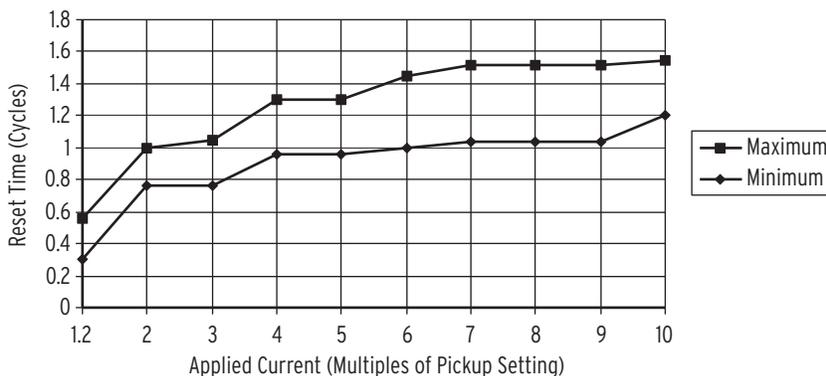
Figure 4.9 SEL-651R-2 Instantaneous Overcurrent Element Reset Time Curve

Neutral Instantaneous/ Definite-Time Overcurrent Elements

GLOBAL SETTING EGNDSW
See Ground Switch Logic on page 4.76.

When Global setting EGNDSW := N, four levels of neutral instantaneous/definite-time overcurrent elements are available. Two additional levels of neutral instantaneous overcurrent elements (Levels 5 and 6) are also available. The different levels are enabled with the E50N enable setting, as shown in *Figure 4.10* and *Figure 4.11*.

When Global setting EGNDSW := Y (factory default), the E50N enable setting is forced to N and the neutral instantaneous/definite-time overcurrent elements are not available. In this application, use the Ground instantaneous/definite-time overcurrent elements (50G1–50G6 and 50G1T–50G4T) described in the next subsection.

To understand the operation of *Figure 4.10* and *Figure 4.11*, follow the explanation given for *Figure 4.1*, *Figure 4.2*, and *Figure 4.3* in the preceding subsection *Phase Instantaneous/ Definite-Time Overcurrent Elements on page 4.1*, substituting current I_N (channel IN current) for phase currents and substituting like settings and Relay Word bits.

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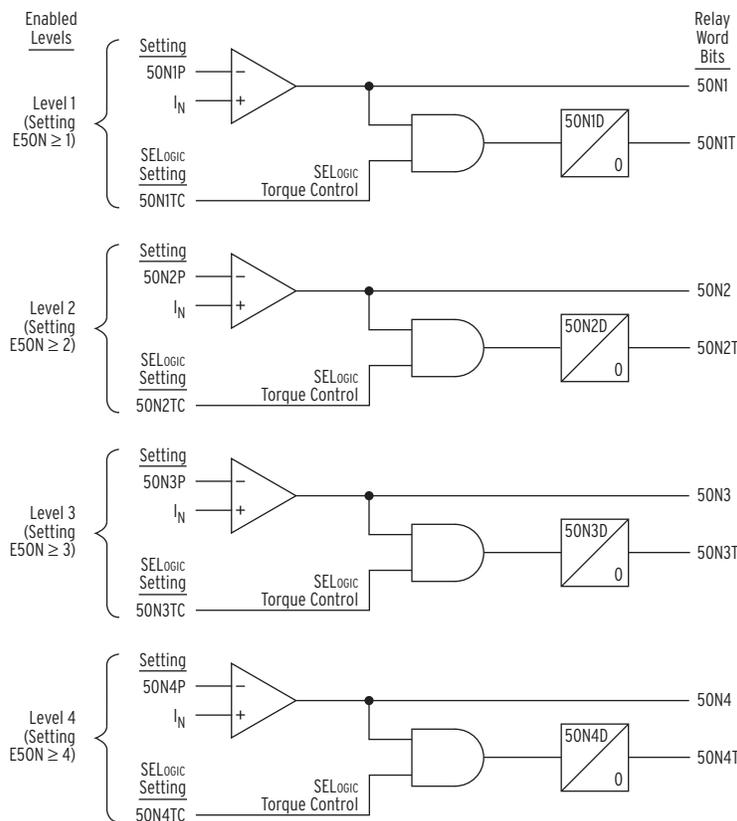
Figure 4.10   Levels 1 Through 4 Neutral Instantaneous/Definite-Time Overcurrent Elements
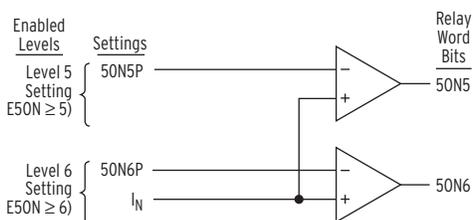
Figure 4.11   Levels 5 Through 6 Neutral Instantaneous Overcurrent Elements

Settings Ranges

NOTE: There is an additional 2-cycle time delay on all the neutral instantaneous (50N1–50N6) and definite-time (50N1T–50N4T) elements. Any time delay provided by the definite-time settings (50N1D–50N4D) is in addition to this 2-cycle time delay.

Setting range for pickup settings 50N1P–50N6P:

0.005–2.500 A secondary

Setting range for definite-time settings 50N1D–50N4D:

0.00–16000.00 cycles, in 0.25-cycle steps

Accuracy

See *Specifications on page 1.9*.

Pickup and Reset Time Curves

See *Figure 4.8* and *Figure 4.9*.

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Ground Instantaneous/ Definite-Time Overcurrent Elements

Four levels of ground instantaneous/definite-time overcurrent elements are available. Two additional levels of ground instantaneous overcurrent elements (Levels 5 and 6) are also available. They operate on ground current I_G that comes from one of two sources:

➤ channel IN current

➤ calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (vector summation)

EGNDSW, CTR, AND CTRN SETTINGS CONFIGURATIONS
See Table 4.23.

CHANNEL IN WIRING CONFIGURATIONS
See Table 4.23.

PHASE CURRENT CHANNEL ASSIGNMENTS
Made with Global setting IPCONN (see Table 9.8).

RESIDUALLY CONNECTED CHANNEL IN
The following figures show the factory-default wiring for channel IN wired residually with the phase current channels for the various recloser applications: Figure 2.49, Figure 2.52, Figure 2.55, Figure 2.59, Figure 2.62, Figure 2.65, Figure 2.68, Figure 2.70, Figure 2.71, Figure 2.76, and Figure 2.77.

The different levels are enabled with the E50G enable setting, as shown in *Figure 4.12* and *Figure 4.13*.

When Global setting EGNDSW := Y, ground current I_G is automatically switched between the following:

➤ channel IN current (for low ground current values)

➤ calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (for higher ground current values)

This gives the ground instantaneous/definite-time overcurrent elements the widest range for pickup settings and operating current. It especially provides for increased sensitivity at lower ground current values. In this application, the pickup settings 50G1P–50G6P must be made on the channel IN current base.

Factory defaults (see Scenario 1 in *Table 4.23*):

➤ Global setting EGNDSW := Y

➤ Channel IN wired residually with the phase current channels

Therefore, the phase channel current base is the same as the channel IN current base and the respective current transformer ratio settings should be set the same (CTR = CTRN).

If uncommon Scenario 2 in *Table 4.23* is true for an SEL-651R-2 installation, then refer to *50G1P Setting Example When EGNDSW := Y and CTR ≠ CTRN on page 4.10* for guidelines on making pickup settings 50G1P–50G6P on the channel IN current base.

When Global setting EGNDSW := N (see Scenarios 3 and 4 in *Table 4.23*), ground current I_G is fixed on the calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (vector summation). In this application, the pickup settings 50G1P–50G6P must be made on the phase current channel base.

To understand the operation of *Figure 4.12* and *Figure 4.13*, follow the explanation given for *Figure 4.1*, *Figure 4.2*, and *Figure 4.3* in the preceding subsection *Phase Instantaneous/ Definite-Time Overcurrent Elements on page 4.1*, substituting ground current I_G (see *Ground Switch Logic on page 4.76*) for phase currents and substituting like settings and Relay Word bits.

Settings Ranges

POSSIBLE EXTRA 2-CYCLE DELAY
For 50G1P–50G6P elements with settings less than 0.050 A secondary (on the phase current base), or when Relay Word bit GNDSW is asserted, there is an additional 2-cycle time delay on the ground instantaneous (50G1–50G6) and definite-time (50G1T–50G4T) element(s). Any time delay provided by definite-time settings 50G1D–50G4D is in addition to this 2-cycle time delay.

Setting range for pickup settings 50G1P–50G6P:

0.005–20.000 A secondary in 0.001-A steps

(on channel IN base*, when Global setting EGNDSW := Y and Group setting CTR = CTRN)

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0.005–[20 • (CTR/CTRN)] A secondary in 0.001-A steps

(on channel IN base, when Global setting EGNDSW := Y and Group setting CTR ≠ CTRN)

0.010–20.000 A secondary in 0.001-A steps

(on IA, IB, IC base, when Global setting EGNDSW := N)

* **Note**: in the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2.

Setting range for definite-time settings 50G1D–50G4D:

0.00–16000.00 cycles, in 0.25-cycle steps

Accuracy

See *Specifications on page 1.9*.

Pickup and Reset Time Curves

See *Figure 4.8* and *Figure 4.9*.

50G1P Setting Example When EGNDSW := Y and CTR ≠ CTRN

In applications where a separate CT is connected to the neutral channel of the SEL-651R-2, the CT ratio is often different than the phase CTs (connected to recloser control terminals I1, I2, I3). If the neutral CT is measuring zero-sequence current from the same line or bus location as the phase CTs, make Global setting EGNDSW := Y and enter the proper CTR and CTRN values in the *Group Settings on page SET.7*.

The SEL-651R-2 ground overcurrent pickup settings must be made on the channel IN base. In this example, the system has 1000:1 phase CTs, a 100:1 neutral CT, and a desired pickup level for a ground element of 75 A primary $(3I_0)$.

Make Global setting EGNDSW := Y and Group settings CTR := 1000.0 and CTRN := 100.0. To determine the proper setting for 50G1P, the primary pickup value (75 A) must be converted to secondary units on the channel IN base.

$$\text{Pickup in secondary}_{(\text{IN base})} = (\text{pickup in primary}) / \text{CTRN}$$

Equation 4.1

Example pickup = 75.0 / 100 = 0.750 A secondary

Make settings

E50G := **1**

50G1P := **0.750 A**

With the calculation method shown in *Equation 4.1*, the phase CT ratio is not used. If the SEL-651R-2 is being installed at a location that already had the ground instantaneous overcurrent setting value calculated on the phase current base, the pickup value must be converted to the IN current base.

Continuing with the example, if the secondary ground trip value was provided on the phase CT base, (use *Equation 4.2* to obtain = 75.0 / 1000 = 0.075 A), the secondary value must be converted to the IN base prior to entry in the SEL-651R-2 (using *Equation 4.3*).

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$$\text{Pickup in secondary}_{(\text{Phase CT base})} = (\text{pickup in primary}) / \text{CTR}$$

Equation 4.2

(Where CTR is the SEL-651R-2 Group setting.)

$$\text{Pickup in secondary}_{(\text{IN base})} = \text{Pickup (IA, IB, IC base)} \cdot (\text{CTR} / \text{CTRN})$$

Equation 4.3

(Where CTR and CTRN are the SEL-651R-2 Group settings.)

Example pickup = Pickup (Phase CT base) • (CTR/CTRN) = 0.075 A • 1000/100 = 0.750 A. The two calculation methods yield the same result.

NOTE: Do not use elements 50G1—50G4 for load unbalance current detection if the fault locator is enabled (setting EFLOC := Y). Set elements 50G1—50G4 above load unbalance current levels so that the fault locator will work correctly. Elements 50G5 and 50G6 may be used for load unbalance current detection.
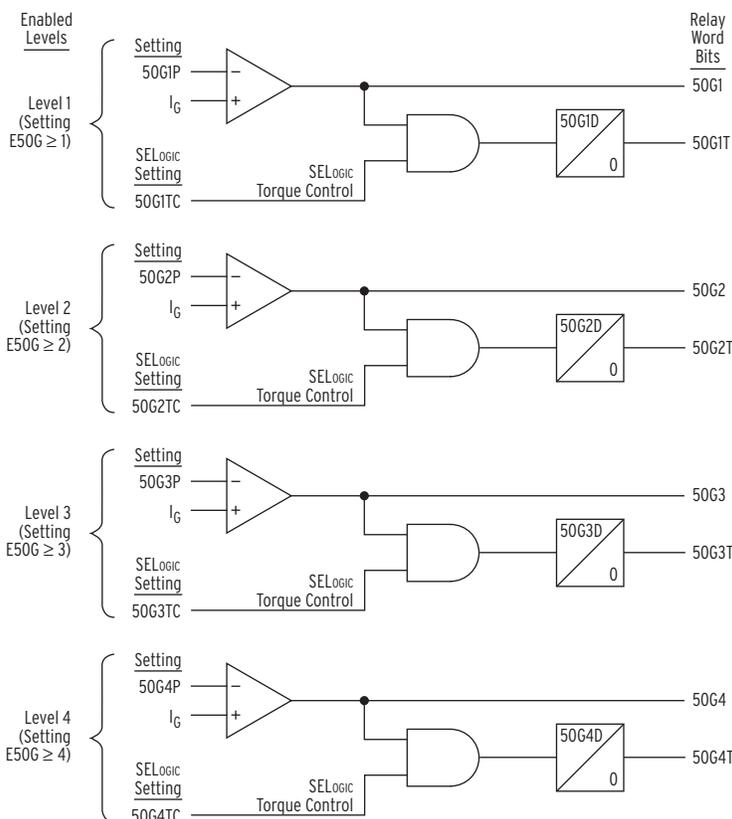
Figure 4.12   Levels 1 Through 4 Ground Instantaneous/Definite-Time Overcurrent Elements
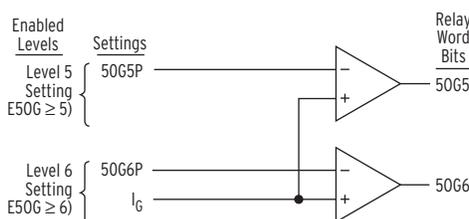
Figure 4.13   Levels 5 Through 6 Ground Instantaneous Overcurrent Elements

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Negative-Sequence Instantaneous/ Definite-Time Overcurrent Elements

Important: See *Setting Negative-Sequence Overcurrent Elements on page 4.105* for information on setting negative-sequence overcurrent elements.

Four levels of negative-sequence instantaneous/definite-time overcurrent elements are available. Two additional levels of negative-sequence instantaneous overcurrent elements (Levels 5 and 6) are also available. The different levels are enabled with the E50Q enable setting, as shown in *Figure 4.14* and *Figure 4.15*.

To understand the operation of *Figure 4.14* and *Figure 4.15*, follow the explanation given for *Figure 4.1*, *Figure 4.2*, and *Figure 4.3* in the preceding subsection *Phase Instantaneous/ Definite-Time Overcurrent Elements on page 4.1*, substituting negative-sequence current $3I_2$ [$3I_2 = I_A + a^2 \cdot I_B + a \cdot I_C$ (ABC rotation), $3I_2 = I_A + a^2 \cdot I_C + a \cdot I_B$ (ACB rotation), where $a = 1 \angle 120°$ and $a^2 = 1 \angle -120°$] for phase currents and substituting like settings and Relay Word bits.

Settings Ranges

Setting range for pickup settings 50Q1P–50Q6P:

  0.05–20.00 A secondary

Setting range for definite-time settings 50Q1D–50Q4D:

  0.00–16000.00 cycles in 0.25-cycle steps

NOTE: Do not use elements 50Q1–50Q4 for load unbalance current detection if the fault locator is enabled (setting EFLOC := Y). Set elements 50Q1–50Q4 above load unbalance current levels so that the fault locator works correctly. Elements 50Q5 and 50Q6 may be used for load unbalance current detection.
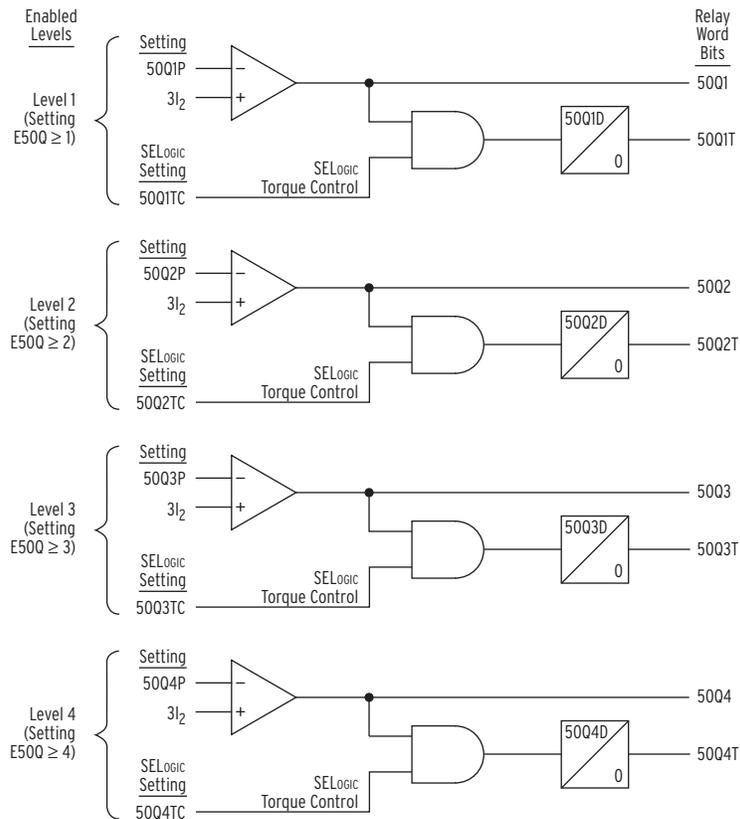
Figure 4.14   Levels 1 Through 4 Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements

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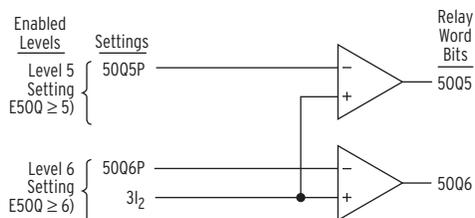
Figure 4.15   Levels 5 Through 6 Negative-Sequence Instantaneous Overcurrent Elements

Accuracy

See *Specifications on page 1.9*.

Pickup and Reset Time Curves

See *Figure 4.8* and *Figure 4.9*.

Time-Overcurrent Elements

The SEL-651R-2 includes seven dual-characteristic time-overcurrent elements, listed in *Table 4.1*.

Table 4.1   Time-Overcurrent Elements in the SEL-651R-2

Name	Figure	Output Relay Word Bits	Enable Setting	Controlling SELOGIC Equations
Maximum Phase	*Figure 4.16*	51P, 51PT, 51PR, 51PS	E51P	51PTC, 51PSW
A-Phase	*Figure 4.17*	51A, 51AT, 51AR, 51AS	E51ABC	51ATC, 51ASW
B-Phase	*Figure 4.18*	51B, 51BT, 51BR, 51BS	E51ABC	51BTC, 51BSW
C-Phase	*Figure 4.19*	51C, 51CT, 51CR, 51CS	E51ABC	51CTC, 51CSW
Neutral #1	*Figure 4.20*	51N1, 51N1T, 51N1R, 51N1S	E51N1	51N1TC, 51N1SW
Neutral #2	*Figure 4.21*	51N2, 51N2T, 51N2R, 51N2S	E51N2	51N2TC, 51N2SW
Ground #1	*Figure 4.22*	51G1, 51G1T, 51G1R, 51G1S	E51G1	51G1TC, 51G1SW
Ground #2	*Figure 4.23*	51G2, 51G2T, 51G2R, 51G2S	E51G2	51G2TC, 51G2SW
Negative-Sequence	*Figure 4.24*	51Q, 51QT, 51QR, 51QS	E51Q	51QTC, 51QSW

The time-overcurrent elements in *Table 4.1* are run in alternating processing intervals:

➤ The phase time-overcurrent elements in one processing interval

➤ The neutral-, ground-, and negative-sequence time-overcurrent elements in the following processing interval

Each time-overcurrent element is run twice per power system cycle. If the SELOGIC control equations in *Table 4.1* are set with rising or falling edge trigger operators (see *Table 7.1*), then there is the possibility that the logical 0 to logical 1 (or 1 to 0) transition of some logic will be missed because of the time-overcurrent elements not being run every processing interval.

See the figures referenced in *Table 4.1* for a block diagram of each element.

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Enable Settings

The dual-characteristic feature allows one of two setting characteristics, labeled J and K, to be used in each time-overcurrent element under SELOGIC control. The dual-characteristic feature is only active for a particular element when the enable setting is set to 2. See *Table 4.1* for the enable setting names.

If the enable setting for a time-overcurrent element is set to 1, the time-overcurrent element only operates from the J characteristic.

If the enable setting for a time-overcurrent element is set to 2, the time-overcurrent element operates from the J or the K characteristic, depending on a Relay Word bit controlled by a SELOGIC control equation, as shown in *Table 4.2*.

Table 4.2   Effect of Enable and Characteristic Switch Settings on 51__ᵃ Elements

Enable Setting	Characteristic Switch Setting	Controlling Relay Word Bit	J Characteristic	K Characteristic
E51__ := N	None	N/A	Disabled	Disabled
E51__ := 1	None	N/A	Active	Disabled
E51__ := 2	51__SW	51__S	Active when 51__S = logical 0	Active when 51__S = logical 1

ᵃ The "__" represents P, A, B, C, N1, N2, G1, G2, or Q.

Characteristic Switch Setting

Refer to the figures referenced in *Table 4.1*. Any one of these figures helps in understanding characteristic switching.

The characteristic switch setting, 51__SW, acts as a request to change the active characteristic. The Relay Word bit 51__S will normally mimic the state of the characteristic switch setting 51__SW. To prevent a change in characteristic during a power system fault, the 51__SW setting is ignored if the time-overcurrent element is picked up (Relay Word bit 51__ is asserted). In this case, the 51__S Relay Word bit will remain at its previous state (just before 51__ asserted) as long as the element remains picked up. After the time-overcurrent element drops out (Relay Word bit 51__ deasserts), the 51__S Relay Word bit again follows the 51__SW setting.

Make the characteristic switch setting, 51__SW, only when the enable setting E51__ := 2. When E51__ := 1, the 51__SW setting is not presented in the **SHO** or **SET** commands (see *Section 10: Communications*) and it is internally set to logical 0.

Relay Word Bits

The time-overcurrent elements each use four Relay Word bits, as shown in *Table 4.1*. The J and the K characteristics share the same Relay Word bits, because only one of J or K characteristics can be active at any time.

The standard event reports indicate which characteristic is in effect for each time-overcurrent element by the use of uppercase or lowercase letters in the digital status columns—see *Table 12.5*.

Torque Control

Each of the dual-characteristic time-overcurrent elements are supervised by a torque-control SELOGIC equation setting (see *Table 4.1*). The torque-control equation controls the entire element, regardless of which characteristic, J or K, is in use.

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Maximum-Phase Time-Overcurrent Elements

The maximum-phase time-overcurrent element is a dual-characteristic element that operates on the maximum phase current (maximum of I_A, I_B, or I_C). See *Table 4.1* for figure references, enable settings, Relay Word bits, and controlling SELOGIC equation names.

Settings Ranges

The 51PT maximum-phase time-overcurrent element settings are shown in *Table 4.3*.

Table 4.3   Maximum-Phase Time-Overcurrent Element Settings

Setting[a]	Definition	Range
51PJP 51PKP	pickup	0.05–3.20 A secondary
51PJC 51PKC	curve type	U1–U5 (U.S. curves; see *Table 9.5*), C1–C5 (IEC curves; see *Table 9.6*), recloser curves (see *Table 9.7*)
51PJTD 51PKTD	time dial (has no multiplying effect on constant time adder or minimum response time)	0.50–15.00 (U.S. curves), 0.05–1.00 (IEC curves), 0.10–2.00 (recloser curves)
51PJRS[b] 51PKRS	electromechanical reset timing	Y, N
51PJCT 51PKCT	constant time adder—adds additional time to curve	0.00–60.00 cycles (no effect if set = 0.00)
51PJMR 51PKMR	minimum response time—flattens curve at set time; curve can operate no faster than this set time	0.00–60.00 cycles (no effect if set = 0.00)
51PTC[c]	SELOGIC control equation torque-control setting	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (=1)
51PSW[d]	SELOGIC characteristic switch setting	Relay Word bits referenced in *Table F.1*

[a] Dual-Characteristic Time-Overcurrent element settings: the letters J and K in the setting names represent the two characteristics.

[b] The electromechanical reset setting (51PJRS) is not available when the curve selection setting (51PJC) is set to a recloser curve. In this situation, 51PJRS is effectively set to N internally. Similarly, setting 51PKRS is not available when setting 51PKC is set to a recloser curve.

[c] SELOGIC control equation torque-control setting (e.g., 51PTC) cannot be set directly to logical 0 or NA.

[d] SELOGIC Characteristic Switch Setting (51PSW) is available only when E51P := 2. 51PSW cannot be set to NA.

See *Time-Overcurrent Curves on page 9.4* for curve selection details.

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NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).
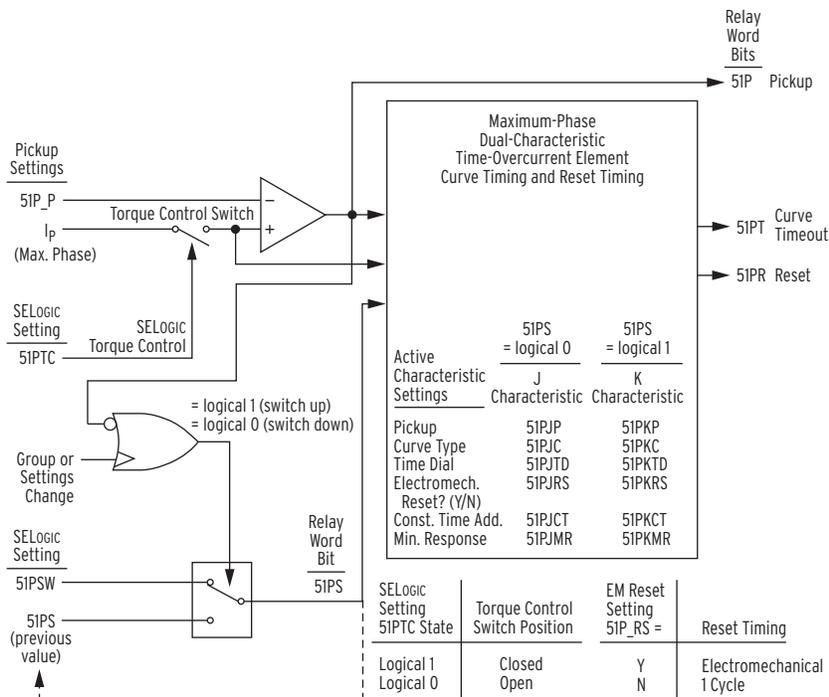
Figure 4.16   Maximum-Phase Dual-Characteristic Time-Overcurrent Element 51PT

Accuracy

See *Specifications on page 1.9*.

Logic Outputs (51PT Element Example)

The resultant logic outputs in *Figure 4.16* are shown in *Table 4.4*.

Table 4.4   Maximum-Phase Time-Overcurrent Element Logic Outputs

Relay Word Bit	Definition/Indication	Application
51P	Maximum phase current, I_P, is greater than phase time-overcurrent element pickup setting 51PJP or 51PKP (depending on 51PS status).	Element pickup testing/indication or fault indication (see FAULT in *Table 5.2* and ABOVE MIN TRIP in *Table 5.3*
51PT	Phase time-overcurrent element is timed out on its curve.	Tripping and other control applications (see *Trip Logic on page 5.1*)
51PR	Phase time-overcurrent element is fully reset.	Element reset testing or other control applications
51PS	Maximum-phase time-overcurrent element is operating on the K characteristic.	Indication, targeting, and event reporting

Torque-Control Switch Operation (51PT Element Example)

The maximum-phase time-overcurrent element J characteristic settings are used in this example, which corresponds to the case where E51P := 1, or where E51P := 2 and the characteristic switch setting 51PSW = logical 0. The

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same torque-control behavior applies to the K characteristic (when 51PSW = logical 1), with the J replaced with K in the settings listed throughout the example.

Torque-Control Switch Closed

The pickup comparator in *Figure 4.16* compares the pickup setting (51PJP) to the maximum phase current, I_P, if the Torque-Control Switch is closed. I_P is also routed to the curve timing/reset timing functions. The Relay Word bit logic outputs operate as follows with the Torque-Control Switch closed:

51P =	1 (logical 1)	if I_P > pickup setting 51PJP and the phase time-overcurrent element is timing or is timed out on its curve
	0 (logical 0)	if $I_P \leq$ pickup setting 51PJP
51PT =	1 (logical 1)	if I_P > pickup setting 51PJP and the phase time-overcurrent element is timed out on its curve
	0 (logical 0)	if I_P > pickup setting 51PJP and the phase time-overcurrent element is timing, but not yet timed out on its curve
	0 (logical 0)	if $I_P \leq$ pickup setting 51PJP
51PR =	1 (logical 1)	if $I_P \leq$ pickup setting 51PJP and the phase time-overcurrent element is fully reset
	0 (logical 0)	if $I_P \leq$ pickup setting 51PJP and the phase time-overcurrent element is timing to reset (not yet fully reset)
	0 (logical 0)	if I_P > pickup setting 51PJP and the phase time-overcurrent element is timing or is timed out on its curve

Torque-Control Switch Open

If the Torque-Control Switch in *Figure 4.16* is open, maximum phase current, I_P, cannot get through to the pickup comparator (setting 51PJP) and the curve timing/reset timing functions. For example, suppose that the Torque-Control Switch is closed, I_P is:

I_P > pickup setting 51PJP

and the phase time-overcurrent element is timing or is timed out on its curve. If the Torque-Control Switch is then opened, I_P effectively appears as a magnitude of zero (0) to the pickup comparator:

I_P = 0 A (effective) < pickup setting 51PJP

resulting in Relay Word bit 51P deasserting to logical 0. I_P also effectively appears as a magnitude of zero (0) to the curve timing/reset timing functions, resulting in Relay Word bit 51PT also deasserting to logical 0. The phase time-overcurrent element then starts to time to reset. Relay Word bit 51PR asserts to logical 1 when the phase time-overcurrent element is fully reset.

Torque-Control Setting

Refer to *Figure 4.16*.

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SEL<small>OGIC</small> control equation torque-control settings (e.g., 51PTC) cannot be set directly to logical 0 or NA. The following are setting examples of SEL<small>OGIC</small> control equation torque-control setting 51PTC for phase time-overcurrent element 51PT.

51PTC := **1**   Setting 51PTC set directly to logical 1: Torque-Control Switch is closed and maximum-phase time-overcurrent element 51PT is enabled.
Note: Some of the overcurrent element SEL<small>OGIC</small> control equation torque-control settings are set directly to logical 1 (e.g., 51PTC := 1) for the factory-default settings. See *Factory-Default Settings on page 9.61* for a list of the factory-default settings.

51PTC := **IN105**   Input IN105 deasserted (51PTC := IN105 = logical 0): The Torque-Control Switch opens and maximum-phase time-overcurrent element 51PT is defeated and nonoperational, regardless of any other setting. Input IN105 asserted (51PTC := IN105 = logical 1): The Torque-Control Switch closes and maximum-phase time-overcurrent element 51PT is enabled.

Reset Timing Details (51PT Element Example)

The maximum-phase time-overcurrent element J characteristic settings are used in this example, which corresponds to the case where E51P := 1, or where E51P := 2, and the characteristic switch setting 51PSW := logical 0. The same reset timing behavior applies to the K characteristic (when 51PSW := logical 1), with the "J" replaced with "K" in the settings listed throughout the example. The J and K characteristics may have different reset settings, for example: 51PJRS := Y and 51PKRS := N. If the characteristic is switched while the element is performing reset timing, the new characteristic will start in the fully reset position.

Refer to *Figure 4.16*.

Any time current I_P goes above pickup setting 51PJP and the phase time-overcurrent element starts timing, Relay Word bit 51PR (reset indication) = logical 0. If the phase time-overcurrent element times out on its curve, Relay Word bit 51PT (curve time-out indication) = logical 1.

Setting 51PJRS := Y

If electromechanical reset timing setting 51PJRS := Y, the maximum-phase time-overcurrent element reset timing emulates electromechanical reset timing (see *Table 9.5* and *Table 9.6*). If maximum phase current, I_P, goes above pickup setting 51PJP (element is timing or already timed out) and then current I_P goes below 51PJP, the element starts to time to reset, emulating electromechanical reset timing. Relay Word bit 51PR (resetting indication) = logical 1 when the element is fully reset.

Setting 51PRS := N

If reset timing setting 51PJRS := N, element 51PT reset timing has a 1-cycle dropout. If current I_P goes above pickup setting 51PJP (element is timing or already timed out) and then current I_P goes below pickup setting 51PJP, there is a 1-cycle delay before the element fully resets. Relay word bit 51PR (reset indication) = logical 1 when the element is fully reset.

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Protection Functions 4.19
Time-Overcurrent Elements

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Single-Phase Time-Overcurrent Elements

The single-phase time-overcurrent elements 51AT, 51BT, and 51CT are dual-characteristic elements that operate on phase currents I_A, I_B, and I_C, respectively. See *Table 4.1* for figure references, enable setting, Relay Word bits, and controlling SELOGIC equation names.

The single-phase elements operate on the individual phase currents, subject to assignment by setting IPCONN—see *Table 9.8*.

The 51AT, 51BT, and 51CT elements are controlled by the enable setting E51ABC. There are separate torque-control and characteristic switch SELOGIC control equation settings for each of the single-phase time-overcurrent elements.

To understand the operation of *Figure 4.17–Figure 4.19*, follow the explanation given for *Figure 4.16* in the preceding subsection *Maximum-Phase Time-Overcurrent Elements on page 4.15*, substituting current I_A, I_B, or I_C (A-phase, B-phase, or C-phase current) for maximum phase current I_P and substituting like settings and Relay Word bits.

Settings Ranges

The single-phase time-overcurrent element settings are shown in *Table 4.5*:

Table 4.5   A-, B-, or C-Phase Time-Overcurrent Element Settings

Setting[a,b]	Definition	Range
51*n*JP 51*n*KP	pickup	0.05–3.20 A secondary
51*n*JC 51*n*KC	curve type	U1–U5 (U.S. curves; see *Table 9.5*), C1–C5 (IEC curves; see *Table 9.6*), recloser curves (see *Table 9.7*)
51*n*JTD 51*n*KTD	time dial (has no multiplying effect on constant time adder or minimum response time)	0.50–15.00 (U.S. curves), 0.05–1.00 (IEC curves), 0.10–2.00 (recloser curves)
51*n*JRS[c] 51*n*KRS	electromechanical reset timing	Y, N
51*n*JCT 51*n*KCT	constant time adder—adds additional time to curve	0.00–60.00 cycles (no effect if set = 0.00)
51*n*JMR 51*n*KMR	minimum response time—flattens curve at set time; curve can operate no faster than this set time	0.00–60.00 cycles (no effect if set = 0.00)
51*n*TC[d]	SELOGIC control equation torque-control setting	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (=1)
51*n*SW[e]	SELOGIC characteristic switch setting	Relay Word bits referenced in *Table F.1*

[a] Dual-Characteristic Time-Overcurrent element settings: the letters J and K in the setting names represent the two characteristics.

[b] n = A, B, or C.

[c] The electromechanical reset setting (51nJRS) is not available when the curve selection setting (51nJC) is set to a recloser curve. In this situation, 51nJRS is effectively set to N internally. Similarly, setting 51nKRS is not available when setting 51nKC is set to a recloser curve.

[d] SELOGIC control equation torque-control setting (e.g., 51nTC) cannot be set directly to logical 0 or NA.

[e] SELOGIC Characteristic Switch Setting (51nSW) is available only when E51ABC := 2. 51nSW cannot be set to NA.

See *Time-Overcurrent Curves on page 9.4* for curve selection details.

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NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).
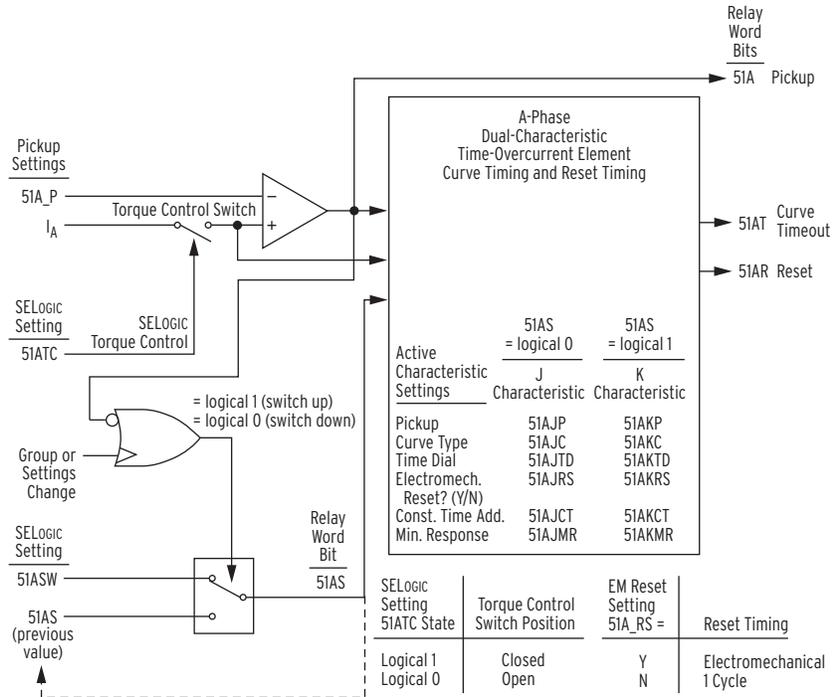
Figure 4.17   A-Phase Time-Overcurrent Element 51AT

NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).
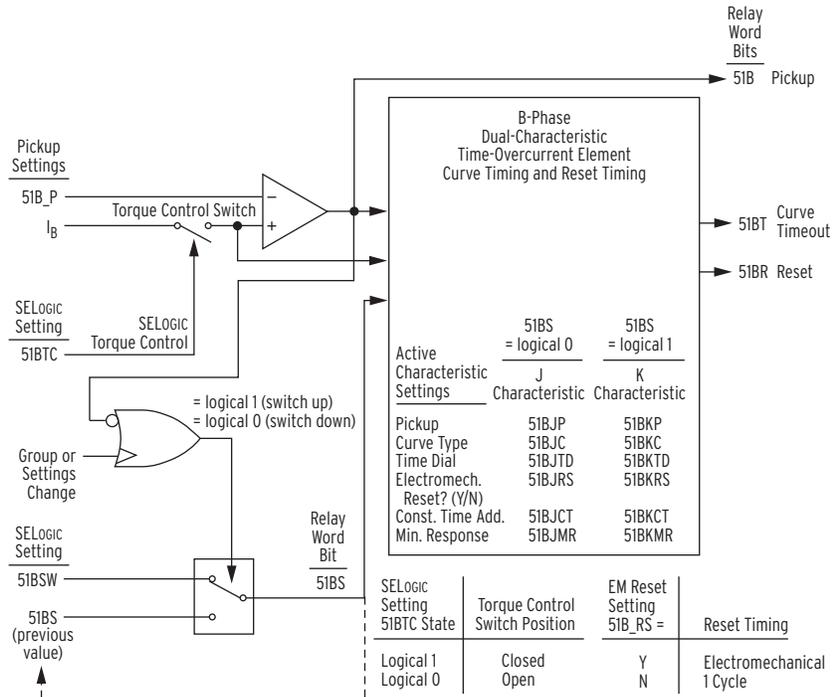
Figure 4.18   B-Phase Time-Overcurrent Element 51BT

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Protection Functions 4.21
Time-Overcurrent Elements

NOTE: Do not use these elements for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels so that the fault locator will work correctly. Use the 5OL element instead for load current detection (see Figure 5.6).
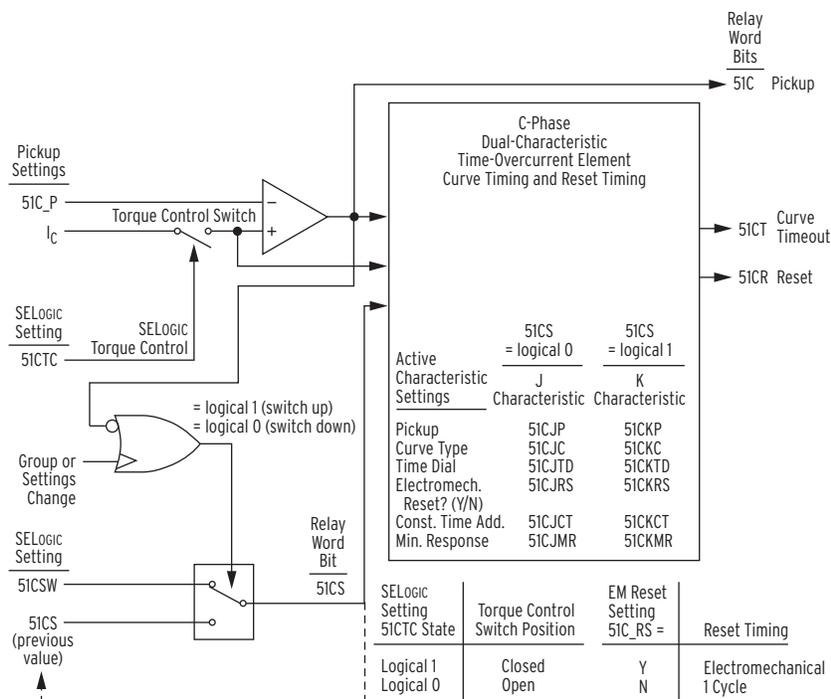
Figure 4.19   C-Phase Time-Overcurrent Element 51CT

Accuracy

See *Specifications on page 1.9*.

Neutral Time-Overcurrent Elements

GLOBAL SETTING EGNDSW
See Ground Switch Logic on page 4.76.

When Global setting EGNDSW := N, two dual-characteristic neutral time-overcurrent elements 51N1T and 51N2T are available. They operate on channel IN current. See *Table 4.1* for figure references, enable settings, Relay Word bits, and controlling SELOGIC equation names.

The neutral time-overcurrent elements 51N1T and 51N2T are controlled by enable settings E51N1 and E51N2, respectively. The neutral time-overcurrent elements are independent, with separate torque-control and characteristic switch SELOGIC control equation settings.

When Global setting EGNDSW := Y (factory default), the E51N1 and E51N2 enable settings are forced to N, disabling the neutral time-overcurrent elements. The ground time-overcurrent elements described in *Ground Time-Overcurrent Elements on page 4.23* are still available.

To understand the operation of *Figure 4.20* and *Figure 4.21*, follow the explanation given for *Figure 4.16* in *Maximum-Phase Time-Overcurrent Elements on page 4.15*, substituting channel IN current for maximum phase current IP and substituting like settings and Relay Word bits.

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Time-Overcurrent Elements

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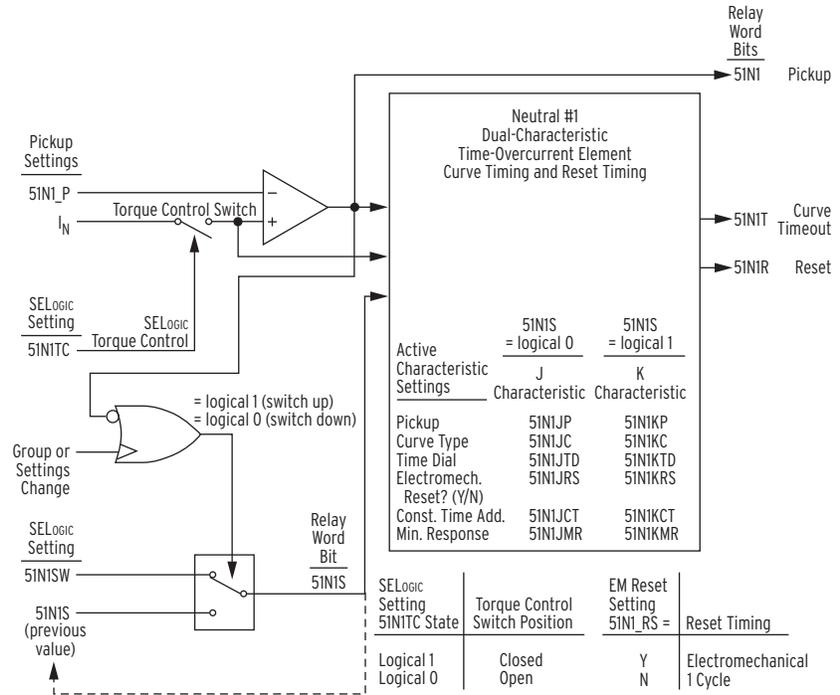
Figure 4.20   Neutral Time-Overcurrent Element 51N1T
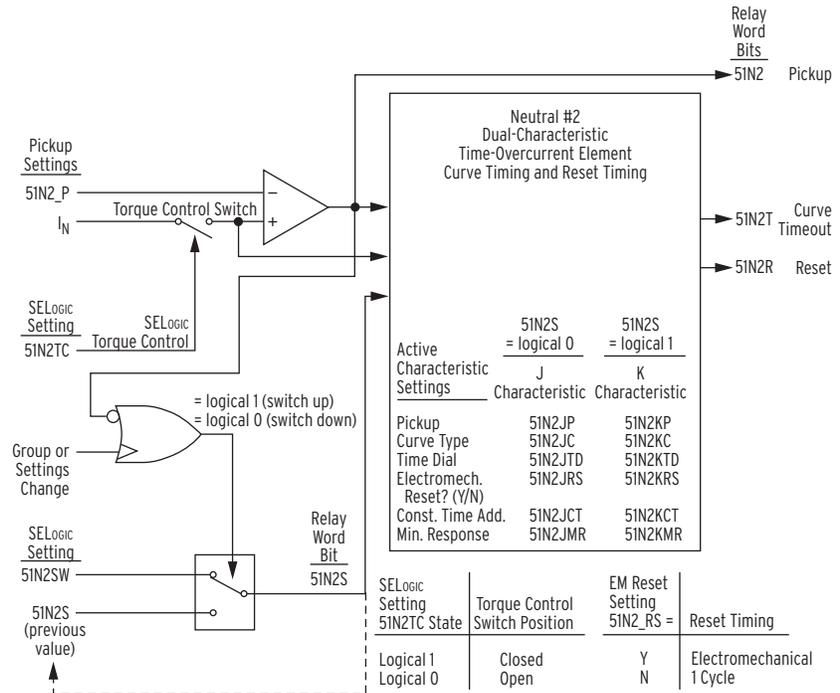
Figure 4.21   Neutral Time-Overcurrent Element 51N2T

Settings Ranges

The neutral time-overcurrent element settings are shown in *Table 4.6*.

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Table 4.6   Neutral Time-Overcurrent Element Settings

Setting[a,b]	Definition	Range
51NnJP 51NnKP	pickup	0.005–0.640 A secondary in 0.001 A steps
51NnJC 51NnKC	curve type	U1–U5 (U.S. curves; see *Table 9.5*), C1–C5 (IEC curves; see *Table 9.6*), recloser curves (see *Table 9.7*)
51NnJTD 51NnKTD	time dial (has no multiplying effect on constant time adder or minimum response time)	0.50–15.00 (U.S. curves), 0.05–1.00 (IEC curves), 0.10–2.00 (recloser curves)
51NnJRS[c] 51NnKRS	electromechanical reset timing	Y, N
51NnJCT 51NnKCT	constant time adder— adds additional time to curve	0.00–60.00 cycles (no effect if set = 0.00)
51NnJMR 51NnKMR	minimum response time—flattens curve at set time; curve can operate no faster than this set time	0.00–60.00 cycles (no effect if set = 0.00)
51NnTC[d]	SELOGIC control equation torque-control setting	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (=1)
51NnSW[e]	SELOGIC characteristic switch setting	Relay Word bits referenced in *Table F.1*

[a] Dual-Characteristic Time-Overcurrent element settings: the letters J and K in the setting names represent the two characteristics.

[b] n = 1 or 2.

[c] The electromechanical reset setting (51NnJRS) is not available when the curve selection setting (51NnJC) is set to a recloser curve. In this situation, 51NnJRS is effectively set to N internally. Similarly, setting 51NnKRS is not available when setting 51NnKC is set to a recloser curve.

[d] SELOGIC control equation torque-control setting (e.g., 51NnTC) cannot be set directly to logical 0 or NA.

[e] SELOGIC Characteristic Switch Setting (51NnSW) is only available when E51Nn := 2. 51NnSW cannot be set to NA.

See *Time-Overcurrent Curves on page 9.4* for curve selection details.

Accuracy

See *Specifications on page 1.9*.

Ground Time-Overcurrent Elements

Two dual-characteristic ground time-overcurrent elements 51G1T and 51G2T are always available. They operate on ground current I_G that comes from one of two sources:

➤ channel IN current

➤ calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (vector summation)

EGNDSW, CTR, AND CTRN SETTINGS CONFIGURATIONS
See Table 4.23.

CHANNEL IN WIRING CONFIGURATIONS
See Table 4.23.

PHASE CURRENT CHANNEL ASSIGNMENTS
Made with Global setting IPCONN (see Table 9.8)

See *Table 4.1* for figure references, enable settings, Relay Word bits, and controlling SELOGIC equation names.

The ground overcurrent elements 51G1T and 51G2T are controlled by enable settings E51G1 and E51G2, respectively. The ground time-overcurrent elements are independent, with separate torque-control and characteristic switch SELOGIC control equation settings.

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Time-Overcurrent Elements

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When Global setting EGNDSW := Y, ground current I_G is automatically switched between the following:

➤ channel IN current (for low ground current values)

➤ calculated residual-ground current $3I_0 = I_A + I_B + I_C$
(for higher ground current values)

This gives the ground time-overcurrent elements the widest range for pickup settings and operating current. It especially provides for increased sensitivity at lower ground current values. In this application, the pickup settings 51G1JP, 51G1KP, 51G2JP, and 51G2KP must be made on the channel IN current base.

Factory defaults (see Scenario 1 in *Table 4.23*):

➤ Global setting EGNDSW := Y

➤ Channel IN wired residually with the phase current channels

Therefore, the phase channel current base is the same as the channel IN current base and the respective current transformer ratio settings should be set the same (CTR = CTRN).

If uncommon Scenario 2 in *Table 4.23* is true for an SEL-651R-2 installation, then refer to *50G1P Setting Example When EGNDSW := Y and CTR ≠ CTRN on page 4.10* for guidelines on making like pickup settings 51G1JP, 51G1KP, 51G2JP, and 51G2KP on the channel IN current base.

When Global setting EGNDSW := N (see Scenarios 3 and 4 in *Table 4.23*), ground current IG is fixed on the calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (vector summation). In this application, the pickup settings 51G1JP, 51G1KP, 51G2JP, and 51G2KP must be made on the phase current channel base.

To understand the operation of *Figure 4.22* and *Figure 4.23*, follow the explanation given for *Figure 4.16* in the preceding subsection *Maximum-Phase Time-Overcurrent Elements on page 4.15*, substituting ground current I_G for maximum phase current I_P and substituting like settings and Relay Word bits.

RESIDUALLY CONNECTED CHANNEL IN
The following figures show the factory-default wiring for channel IN wired residually with the phase current channels for the various recloser applications: Figure 2.49, Figure 2.52, Figure 2.55, Figure 2.59, Figure 2.62, Figure 2.65, Figure 2.68, Figure 2.70, Figure 2.71, Figure 2.76, and Figure 2.77.

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Protection Functions 4.25
Time-Overcurrent Elements

NOTE: Do not use these elements for load unbalance current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load unbalance current levels so that the fault locator will work correctly.
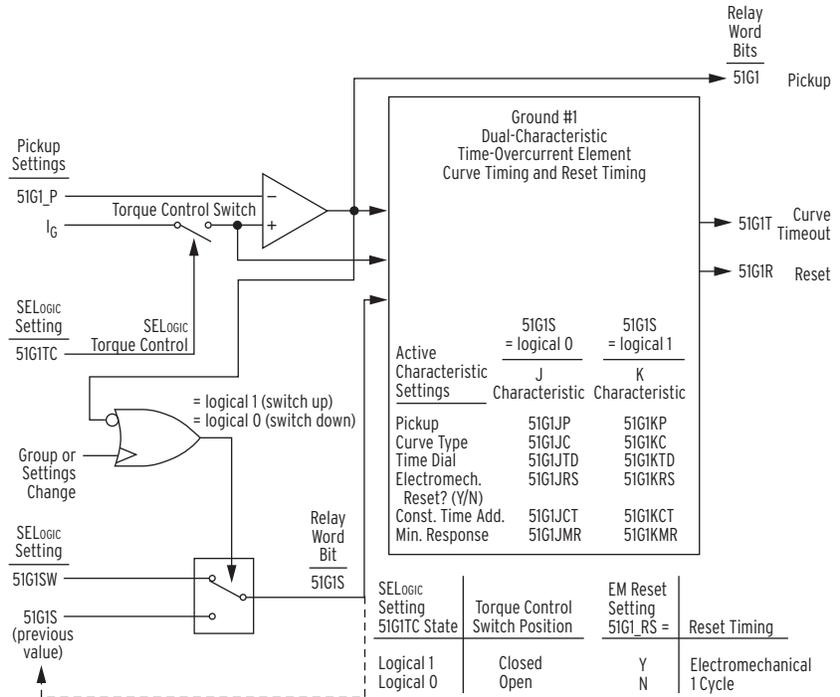
Figure 4.22   Ground Time-Overcurrent Element 51G1T

NOTE: Do not use these elements for load unbalance current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load unbalance current levels so that the fault locator will work correctly.
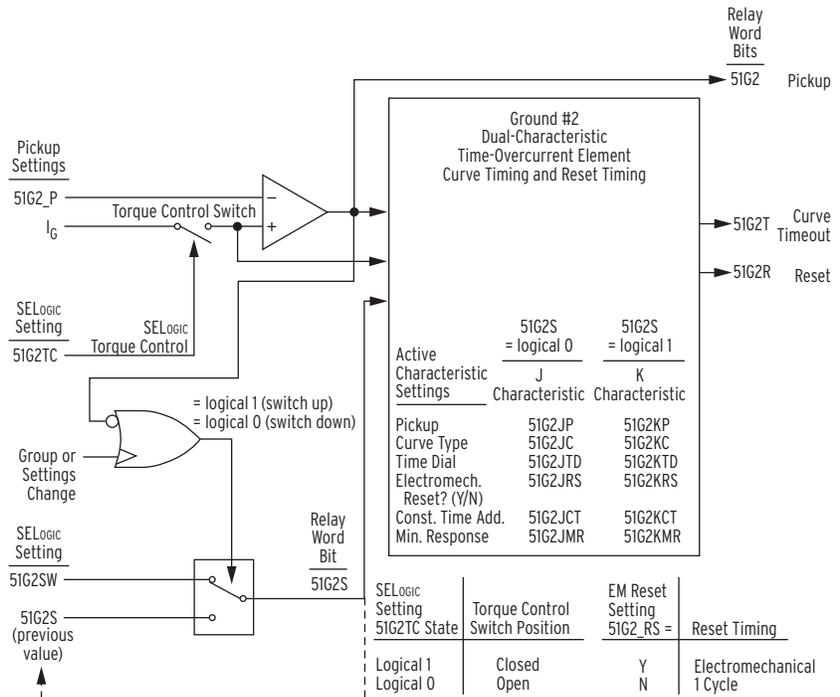
Figure 4.23   Ground Time-Overcurrent Element 51G2T

Settings Ranges

The ground time-overcurrent element settings are shown in *Table 4.7*.

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Time-Overcurrent Elements

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Table 4.7   Ground Time-Overcurrent Element Settings

Setting[a,b]	Definition	Range

51G*n*JP
51G*n*KP
	pickup	0.005–3.200 A
		secondary in 0.001 A steps
		  (on channel IN base[c], when
		  Global setting EGNDSW := Y
		  and Group setting CTR = CTRN)
		0.005–[3.2 • (CTR/CTRN)] A
		secondary in 0.001 A steps
		  (on channel IN base[c], when
		  Global setting EGNDSW := Y
		  and Group setting CTR ≠ CTRN)
		0.020–3.200 A secondary in 0.001 A
		steps
		  (on IA, IB, IC base[c], when
		  Global setting EGNDSW := N)

51G*n*JC 51G*n*KC	curve type	U1–U5 (U.S. curves; see *Table 9.5*), C1–C5 (IEC curves; see *Table 9.6*), recloser curves (see *Table 9.7*)
51G*n*JTD 51G*n*KTD	time dial (has no multiplying effect on constant time adder or minimum response time)	0.50–15.00 (U.S. curves), 0.05–1.00 (IEC curves), 0.10–2.00 (recloser curves)
51G*n*JRS[d] 51G*n*KRS	electromechanical reset timing	Y, N
51G*n*JCT 51G*n*KCT	constant time adder— adds additional time to curve	0.00–60.00 cycles (no effect if set = 0.00)
51G*n*JMR 51G*n*KMR	minimum response time—flattens curve at set time; curve can operate no faster than this set time	0.00–60.00 cycles (no effect if set = 0.00)
51G*n*TC[e]	SELOGIC control equation torque-control setting	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (=1)
51G*n*SW[f]	SELOGIC characteristic switch setting	Relay Word bits referenced in *Table F.1*

[a] Dual-Characteristic Time-Overcurrent element settings: the letters J and K in the setting names represent the two characteristics.

[b] n = 1 or 2.

[c] In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2. The scaling considerations for the ground time-overcurrent elements are identical to the ground instantaneous/definite-time overcurrent elements—see 50G1P Setting Example When EGNDSW := Y and CTR ≠ CTRN on page 4.10.

[d] The electromechanical reset setting (51GnJRS) is not available when the curve selection setting (51GnJC) is set to a recloser curve. In this situation, 51GnJRS is effectively set to N internally. Similarly, setting 51GnKRS is not available when setting 51GnKC is set to a recloser curve.

[e] SELOGIC control equation torque-control setting (e.g., 51GnTC) cannot be set directly to logical 0 or NA.

[f] SELOGIC Characteristic Switch Setting (51GnSW) is only available when E51Gn := 2. 51GnSW cannot be set to NA.

See *Time-Overcurrent Curves on page 9.4* for curve selection details.

Accuracy

See *Specifications on page 1.9*.

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Negative-Sequence Time-Overcurrent Element

The negative-sequence time-overcurrent element 51QT is a dual-characteristic element that operates from the calculated negative-sequence currents $3I_2$. See *Table 4.1* for figure references, enable settings, Relay Word bits, and controlling SELOGIC equation names.

The 51QT element is controlled by the enable setting E51Q.
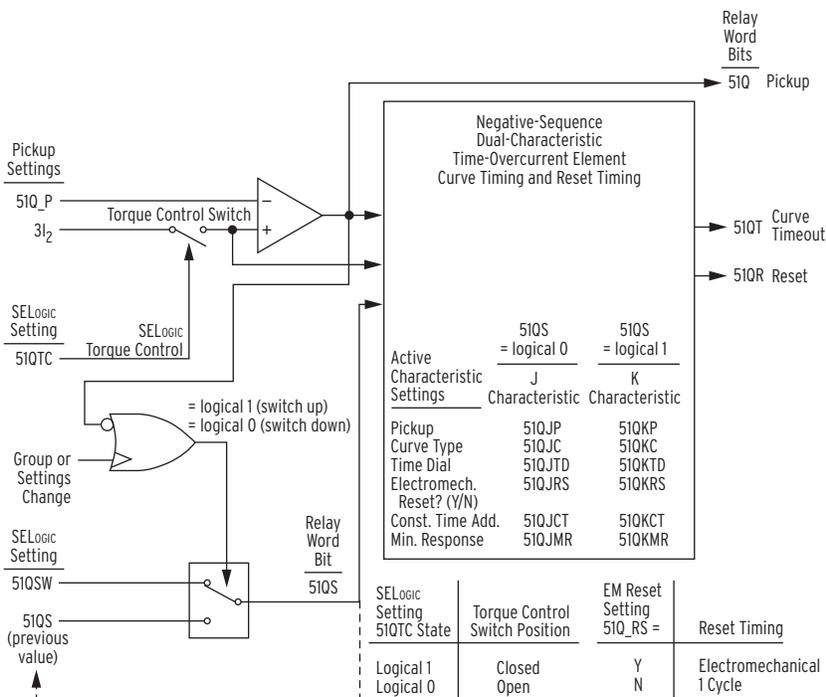
Figure 4.24   Negative-Sequence Time-Overcurrent Element 51QT

IMPORTANT: See Setting Negative-Sequence Time-Overcurrent Elements on page 4.105 for information on setting negative-sequence overcurrent elements.

To understand the operation of *Figure 4.24*, follow the explanation given for *Figure 4.16* in the preceding subsection *Maximum-Phase Time-Overcurrent Elements on page 4.15*, substituting negative-sequence current $3I_2$ [$3I_2 = I_A + a^2 \cdot I_B + a \cdot I_C$ (ABC rotation), $3I_2 = I_A + a^2 \cdot I_C + a \cdot I_B$ (ACB rotation), where $a = 1 \angle 120°$ and $a^2 = 1 \angle -120°$] for maximum phase current I_P and substituting like settings and Relay Word bits.

Settings Ranges

The negative-sequence time-overcurrent element settings are shown in *Table 4.8*.

Table 4.8   Negative-Sequence Time-Overcurrent Element Settings (Sheet 1 of 2)

Setting[a]	Definition	Range
51QJP 51QKP	pickup	0.05–3.20 A secondary
51QJC 51QKC	curve type	U1–U5 (U.S. curves; see *Table 9.5*), C1–C5 (IEC curves; see *Table 9.6*), recloser curves (see *Table 9.7*)
51QJTD 51QKTD	time dial (has no multiplying effect on constant time adder or minimum response time)	0.50–15.00 (U.S. curves), 0.05–1.00 (IEC curves), 0.10–2.00 (recloser curves)
51QJRS[b] 51QKRS	electromechanical reset timing	Y, N

4.28 | Protection Functions
Second-Harmonic Blocking Logic

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Table 4.8 Negative-Sequence Time-Overcurrent Element Settings (Sheet 2 of 2)

Setting[a]	Definition	Range
51QJCT 51QKCT	constant time adder— adds additional time to curve	0.00–60.00 cycles (no effect if set = 0.00)
51QJMR 51QKMR	minimum response time—flattens curve at set time; curve can operate no faster than this set time	0.00–60.00 cycles (no effect if set = 0.00)
51QTC[c]	SELOGIC control equation torque-control setting	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (=1)
51QSW[d]	SELOGIC characteristic switch setting	Relay Word bits referenced in *Table F.1*

[a] Dual-Characteristic Time-Overcurrent element settings: the letters J and K in the setting names represent the two characteristics.

[b] The electromechanical reset setting (51QJRS) is not available when the curve selection setting (51QJC) is set to a recloser curve. In this situation, 51QJRS is effectively set to "N" internally. Similarly, setting 51QKRS is not available when setting 51QKC is set to a recloser curve.

[c] SELOGIC control equation torque-control setting (e.g., 51QTC) cannot be set directly to logical 0 or NA.

[d] SELOGIC Characteristic Switch Setting (51QSW) is available only when E51Q := 2. 51QSW cannot be set to NA.

See *Time-Overcurrent Curves on page 9.4* for curve selection details.

Accuracy

See *Specifications on page 1.9*.

Second-Harmonic Blocking Logic

When a distribution feeder supplies many transformers, magnetizing inrush currents may cause sensitive overcurrent elements to operate when the line is energized. The second-harmonic blocking logic can prevent this by blocking such elements until inrush currents have subsided. As shown in *Figure 4.25*, this logic uses the ratio of the second-harmonic content of each phase to the fundamental current of the same phase to calculate the percent second-harmonic content.

When SELOGIC torque-control equation HBL2TC = logical 1, and if the second-harmonic content exceeds the adjustable pickup threshold (HBL2P) for the pickup time delay (HBL2PU), the blocking Relay Word bit for that phase asserts. Once asserted, if the second-harmonic content falls below the threshold for the dropout time delay (HBL2DO), the output deasserts. If any of the phase outputs assert, Relay Word bit HBL2T also asserts.

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Second-Harmonic Blocking Logic
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Table 4.9   Second-Harmonic Blocking Settings

Setting	Definition	Range
EHBL2	Enable Second-Harmonic Blocking	Y, N
HBL2P	Second-Harmonic Pickup Threshold	5–100%
HBL2PU	Second-Harmonic Blocking Timer Pickup	0.00–16,000.00 cycles
HBL2DO	Second-Harmonic Blocking Timer Dropout	0.00–16,000.00 cycles
HBL2TC	Second-Harmonic Blocking Torque Control	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (= 1)[a]

[a] SELOGIC control equation torque-control settings (e.g., HBL2TC) cannot be set directly to logical 0.
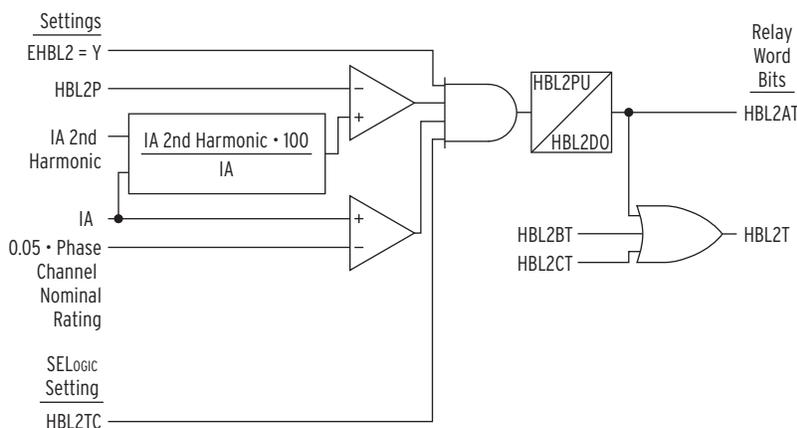
Figure 4.25   Second-Harmonic Blocking Logic

Table 4.10   Second-Harmonic Blocking Logic Outputs

Relay Word Bit	Definition	Application
HBL2AT	A-phase second-harmonic element timed out	Overcurrent element control
HBL2BT	B-phase second-harmonic element timed out	Overcurrent element control
HBL2CT	C-phase second-harmonic element timed out	Overcurrent element control
HBL2T	One or more phases second-harmonic element timed out	Overcurrent element control

Second-harmonic blocking elements are typically used to supervise sensitive overcurrent elements. CT saturation during faults can cause the relay to measure second-harmonic current. The second-harmonic blocking element may also assert briefly when the fundamental frequency current changes. Either condition might delay the supervised element. Set an unsupervised element above the expected inrush current to provide fast protection during large faults. Set the second-harmonic blocking timer pickup for more than one cycle in applications that cannot tolerate the element operating because of current changes.

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Second-Harmonic Blocking Logic

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Settings Examples

Instantaneous Overcurrent Element Blocking

In this example, including second-harmonic blocking element HBL2T in the torque-control equation for Level 1 Phase Overcurrent element 50P1 helps prevent operation because of transformer inrush.

50P1P = **2.00 A**

50P2P = **4.00 A**

50P1D = **2.00 cycles**

50P1TC = **NOT HBL2T**

50P2TC = **1**

TR3P = **...OR 50P1T OR 50P2T OR...**

The Level 1 time delay 50P1D allows time for the blocking element to assert. Level 2 Phase Overcurrent element setting 50P2P is high enough that the element will not operate when the line is energized but low enough to operate for high-current faults when current transformer saturation or fundamental frequency current change might briefly block the Level 1 element.

Time-Overcurrent Element Blocking

For time-overcurrent elements, it may be desirable for the element to continue timing when transformer inrush is detected, yet trip the breaker if the time-overcurrent element remains asserted after the inrush conditions have subsided.

51PJP = **1.2 A**

HBL2DO = **2.00 cycles**

51PTC = **1**

TR3P = **...OR 51PT AND NOT HBL2T OR...**

ER = **...OR R_TRIG 51P OR R_TRIG 51PT OR...**

In this example, 51PT is allowed to assert regardless of the state of the second-harmonic blocking element. However, 51PT cannot cause a trip if HBL2T is asserted. Dropout timer HBL2DO ensures that the blocking condition is maintained until 51PT deasserts. If electromechanical reset is disabled (51PR = N), 51PT remains asserted for 1 cycle after the phase current falls below pickup setting 51PJP. HBL2DO may be increased to provide additional security should the second-harmonic current fall below the pickup threshold before the fundamental frequency current falls below the overcurrent element pickup. Because the relay may not trip when 51PT asserts, the ER Event Report Trigger SELOGIC control equation is modified to trigger an event report. This event report can be used to evaluate the effectiveness of the harmonic blocking and determine if setting adjustments are necessary.

Changing the Pickup of a Time-Overcurrent Element

Use the second-harmonic blocking elements to increase the pickup current of a time-overcurrent element during inrush conditions without changing the time delay characteristics. For example,

51PJP = **1.2 A**

50P3P = **2.5 A**

51PTC = **NOT HBL2T OR 50P3**

TR3P = **...OR 51PT OR...**

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In this example, the 51P time-overcurrent element operates if the second-harmonic blocking element is deasserted or the phase current exceeds the Level 3 Phase Instantaneous Overcurrent setting. If second-harmonic blocking is asserted and the phase current is below the Level 3 Phase Instantaneous Overcurrent setting, the time-overcurrent element 51P does not operate. Thus the pickup of the 51P element is increased from 1.2 A secondary to 2.5 A secondary during inrush. Once the maximum phase current exceeds 50P3P, the timing of the 51P element does not change, so coordination is maintained for large faults.

As shown in *Figure 4.16*, if torque-control equation 51PTC deasserts, the Level 1 phase time-overcurrent element may fully or partially reset. When second-harmonic blocking elements are included in torque-control equations for time-overcurrent elements, the element will need to time from reset after the blocking element deasserts. Consider this when evaluating time-overcurrent coordination and when reviewing event reports in which harmonic blocking has operated.

Voltage Elements

Enable numerous voltage elements by making the Enable setting:

EVOLT := **N (None), VY, VZ, or BOTH**

The VY-terminal voltage elements are enabled when EVOLT := VY or BOTH. The VZ-terminal voltage elements are enabled if EVOLT := VZ or BOTH.

Voltage Values

The VY-terminal voltage elements operate off of Y-terminal voltage values shown in *Table 4.11* (Z-terminal is similar—see terminals in *Figure 2.42*).

Table 4.11   Voltage Values Used by VY-Terminal Voltage Elements (VZ-Terminal Similar)

Voltage	Description
$V_{A(Y)}$	A-phase voltage[a]
$V_{B(Y)}$	B-phase voltage[a]
$V_{C(Y)}$	C-phase voltage[a]
$V_{AB(Y)}$	Phase-to-phase voltage
$V_{BC(Y)}$	Phase-to-phase voltage
$V_{CA(Y)}$	Phase-to-phase voltage
$3V_{0(Y)}$	Zero-sequence voltage
$V_{2(Y)}$	Negative-sequence voltage
$V_{1(Y)}$	Positive-sequence voltage

[a] Global setting VYCONN determines the assignment of VY-terminal voltage inputs V1Y, V2Y, and V3Y to phases A, B, and C, thus allowing voltages $V_{A(Y)}$, $V_{B(Y)}$, and $V_{C(Y)}$ to be derived (see Table 9.9).

Voltage Element Settings

Table 4.12 lists available voltage elements and the corresponding voltage inputs and settings ranges for SEL-651R-2 recloser controls.

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Table 4.12   VY-Terminal Voltage Elements Settings and Settings Ranges (VZ-Terminal Similar)

Voltage Element (Relay Word Bits)	Operating Voltage	Pickup Setting/Range	See Figure
27YA1	$V_{A(Y)}$	27YP1P 1.00–300.00 V secondary	*Figure 4.26* (for similar Z-terminal voltage elements, *Figure 4.28*)
27YB1	$V_{B(Y)}$		
27YC1	$V_{C(Y)}$		
3P27Y := 27A1 AND 27B1 AND 27C1			
27YA2	$V_{A(Y)}$	27YP2P 1.00–300.00 V secondary	
27YB2	$V_{B(Y)}$		
27YC2	$V_{C(Y)}$		
59YA1	$V_{A(Y)}$	59YP1P 1.00–300.00 V secondary	
59YB1	$V_{B(Y)}$		
59YC1	$V_{C(Y)}$		
3P59Y := 59YA1 AND 59YB1 AND 59YC1			
59YA2	$V_{A(Y)}$	59YP2P 1.00–300.00 V secondary	
59YB2	$V_{B(Y)}$		
59YC2	$V_{C(Y)}$		
27YAB1	$V_{AB(Y)}$	27YPP1P 1.76–520.00 V secondary	*Figure 4.27* (for similar Z-terminal voltage elements, *Figure 4.29*)
27YBC1	$V_{BC(Y)}$		
27YCA1	$V_{CA(Y)}$		
59YAB1	$V_{AB(Y)}$	59YPP1P 1.76–520.00 V secondary	
59YBC1	$V_{BC(Y)}$		
59YCA1	$V_{CA(Y)}$		
59YN1	$3V_{0(Y)}$	59YN1P 2.00–300.00 V secondary	
59YN2	$3V_{0(Y)}$	59YN2P 2.00–300.00 V secondary	
59YQ1	$V_{2(Y)}$	59YQ1P 2.00–300.00 V secondary	
59YV1	$V_{1(Y)}$	59YV1P 2.00–300.00 V secondary	

The SEL-651R-2 voltage inputs are available as 300 Vac maximum inputs or as a variety of low-energy analog (LEA) inputs. The settings (in *Table 4.12*) are on the 300 Vac base.

If LEA inputs are ordered, the voltage element pickup values must be adjusted prior to making the settings (see *PT Ratio Setting Adjustments on page 9.42* and *Voltage-Related Settings and LEA Inputs (Group Settings) on page 9.47*).

The voltage elements in the SEL-651R-2 are *not affected* by the Global settings VSELECT and EPHANT (see *Enable Phantom Voltage Setting (EPHANT) on page 9.33* and *Voltage Source Selection Setting (VSELECT) on page 9.33*).

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Settings/
Voltages

Relay
Word
Bits
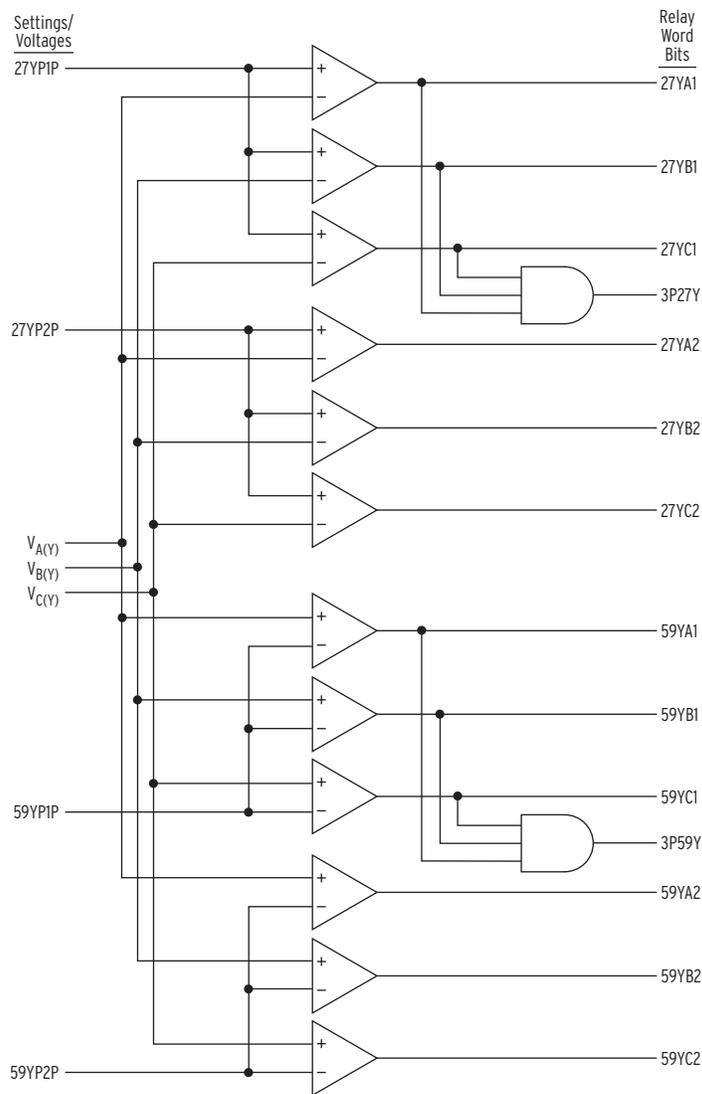
Figure 4.26   VY-Terminal Single-Phase and Three-Phase Voltage Elements

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Voltages

Relay
Word
Bits

27YPP1P

27YAB1

27YBC1

27YCA1

$V_{AB(Y)}$
$V_{BC(Y)}$
$V_{CA(Y)}$

59YAB1

59YBC1

59YPP1P

59YCA1

$3V_{0(Y)}$
59YN1P

59YN1

59YN2P

59YN2

$V_{2(Y)}$
59YQ1P

59YQ1

$V_{1(Y)}$
59YV1P

59YV1
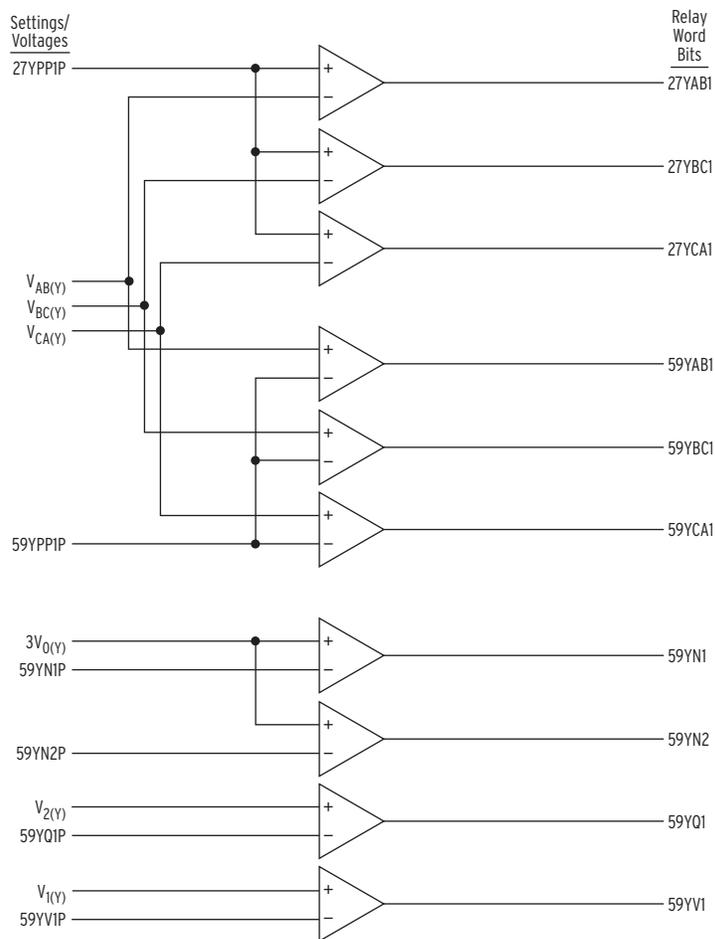
Figure 4.27   VY‑Terminal Phase‑to‑Phase and Sequence Voltage Elements

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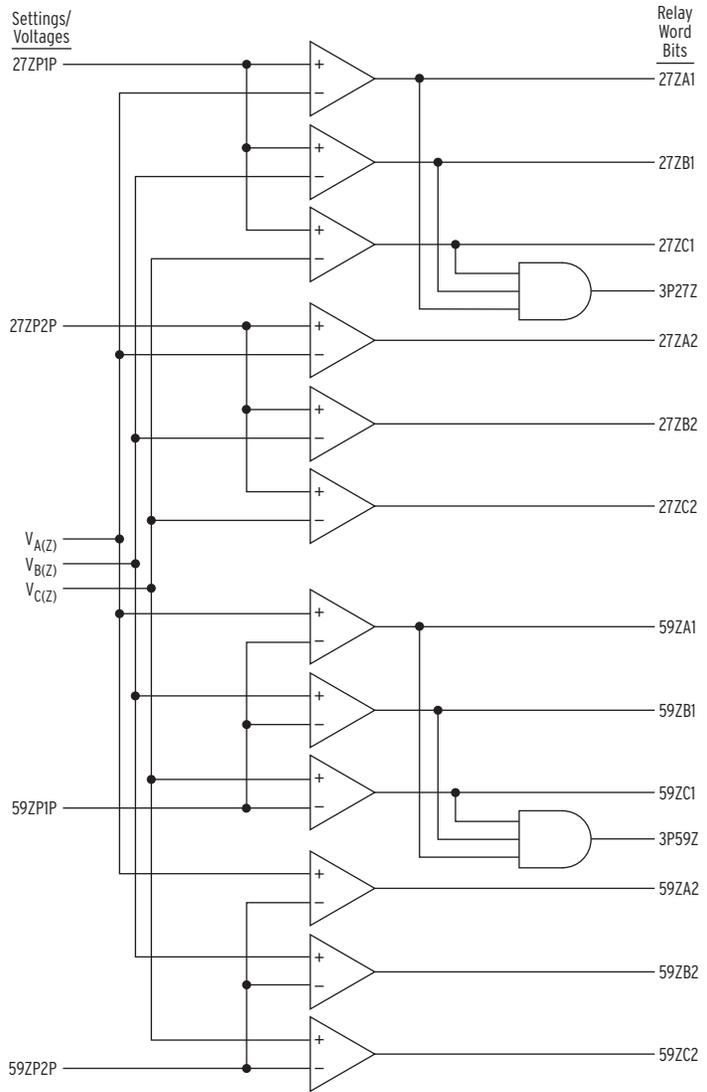
Figure 4.28   VZ-Terminal Single-Phase and Three-Phase Voltage Elements

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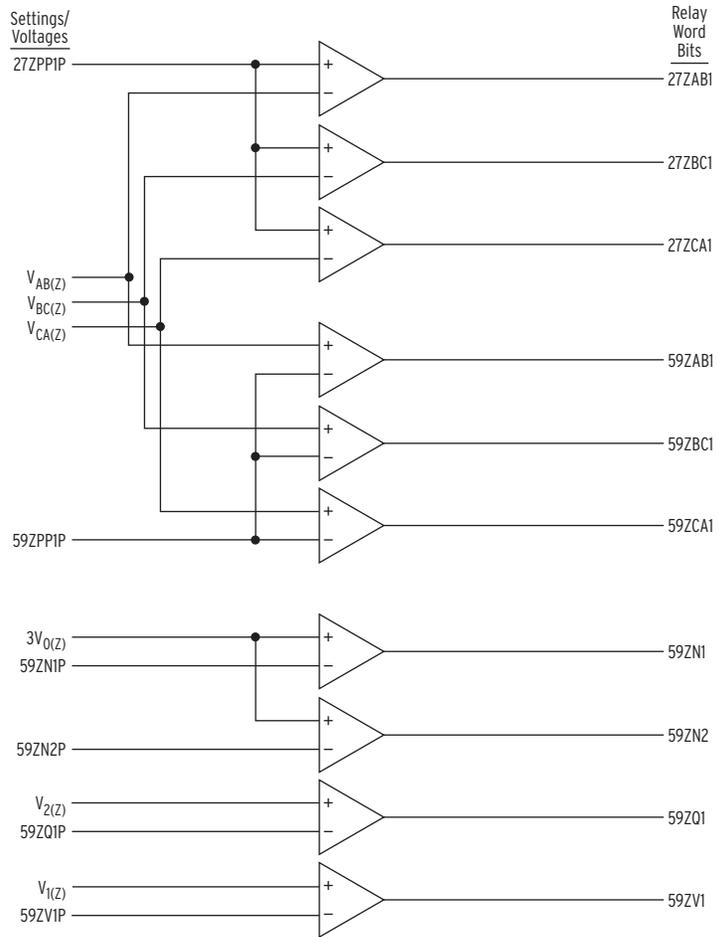
Figure 4.29   VZ-Terminal Phase-to-Phase and Sequence Voltage Elements

Accuracy

See *Specifications on page 1.9*.

Voltage Element Operation

Note that the voltage elements in *Table 4.12* and *Figure 4.26–Figure 4.29* are a combination of "undervoltage" (Device 27) and "overvoltage" (Device 59) type elements. Undervoltage elements (Device 27) assert when the operating voltage goes below the corresponding pickup setting. Overvoltage elements (Device 59) assert when the operating voltage goes above the corresponding pickup setting.

Undervoltage Element Operation Example

Refer to *Figure 4.26* (top of the figure).

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Pickup setting 27YP1P is compared to the magnitudes of the individual phase voltages $V_{A(Y)}$, $V_{B(Y)}$, and $V_{C(Y)}$. The logic outputs in *Figure 4.26* are the following Relay Word bits:

27YA1 =	1 (logical 1)	if $V_{A(Y)}$ < pickup setting 27YP1P
	0 (logical 0)	if $V_{A(Y)}$ ≥ pickup setting 27YP1P
27YB1 =	1 (logical 1)	if $V_{B(Y)}$ < pickup setting 27YP1P
	0 (logical 0)	if $V_{B(Y)}$ ≥ pickup setting 27YP1P
27YC1 =	1 (logical 1)	if $V_{C(Y)}$ < pickup setting 27YP1P
	0 (logical 0)	if $V_{C(Y)}$ ≥ pickup setting 27YP1P
3P27Y =	1 (logical 1)	if all three Relay Word bits 27YA1, 27YB1, and 27YC1 are asserted (27YA1 = 1, 27YB1 = 1, and 27YC1 = 1)
	0 (logical 0)	if at least one of the Relay Word bits 27YA1, 27YB1, or 27YC1 is deasserted (e.g., 27YA1 = 0)

Overvoltage Element Operation Example

Refer to *Figure 4.26* (bottom of the figure).

Pickup setting 59YP1P is compared to the magnitudes of the individual phase voltages $V_{A(Y)}$, $V_{B(Y)}$, and $V_{C(Y)}$. The logic outputs in *Figure 4.26* are the following Relay Word bits:

59YA1 =	1 (logical 1)	if $V_{A(Y)}$ > pickup setting 59YP1P
	0 (logical 0)	if $V_{A(Y)}$ ≤ pickup setting 59YP1P
59YB1 =	1 (logical 1)	if $V_{B(Y)}$ > pickup setting 59YP1P
	0 (logical 0)	if $V_{B(Y)}$ ≤ pickup setting 59YP1P
59YC1 =	1 (logical 1)	if $V_{C(Y)}$ > pickup setting 59YP1P
	0 (logical 0)	if $V_{C(Y)}$ ≤ pickup setting 59YP1P
3P59Y =	1 (logical 1)	if all three Relay Word bits 59YA1, 59YB1, and 59YC1 are asserted (59YA1 = 1, 59YB1 = 1, and 59YC1 = 1)
	0 (logical 0)	if at least one of the Relay Word bits 59YA1, 59YB1, or 59YC1 is deasserted (e.g., 59YA1 = 0)

Detecting Absence of Voltage with Various LEA Voltage Inputs

Refer to *PT Ratio Setting Adjustments on page 9.42* and *Voltage-Related Settings and LEA Inputs (Group Settings) on page 9.47* for voltage divider information and background for connecting to various LEA voltage inputs. Using 8 Vac LEA voltage inputs as an example, convert low-end pickup setting 27YP1P = 1.00 V (300 V base) to the 8 V base:

1.00 V • 8/300 = 0.0267 V (8 V base)

The accuracy variation for the effective 0.0267 V (8 V base) pickup setting (from *Specifications on page 1.9*) is:

0.01 V + 0.0267 V • (0.01) = 0.01 V (8 V base)

So, the effective 0.0267 V (8 V base) pickup could vary from:

0.0167 V (= 0.0267 V – 0.01 V)
  to
0.0367 V (= 0.0267 V + 0.01 V)

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Converting the effective pickup (with "positive" variation) 0.0367 V (8 V base) to the primary voltage level (via the 10,000 ratio voltage divider for 8 V LEA applications) results in:

0.0367 V • 10,000 = 367 V primary

Apply this resultant primary value to a 4.16 kV primary system (2.4 kV phase-to-neutral):

(367 V/2400 V) • 100% = 15.3%

An adequate voltage measurement to determine absence of voltage on a 4.16 kV primary system is 15.3% of nominal voltage (which includes the above stated "positive" accuracy variation). Again, this is achieved with the previously mentioned example pickup setting 27YP1P = 1.00 V (300 V base).

Alternatively, for a 12.47 kV primary system (7.2 kV phase-neutral), 15% of nominal voltage would extrapolate to the following voltage on the the 8 V LEA input:

(15%/100%) • (7200 V/10,000) = 0.108 V (8 V base)

Factoring in accuracy variation, the effective 0.108 V (8 V base) pickup could vary from:

0.098 V (= 0.108 V – 0.01 V)
    to
0.118 V (= 0.108 V + 0.01 V)

This is a much tighter variation than the preceding 4.16 kV primary system example, because a 12.47 kV primary system provides more signal to the 10,000 ratio voltage divider than does a 4.16 kV primary system. The 27YP1P pickup setting (300 V base) for this 12.47 kV primary system example (15% of nominal voltage) would be:

0.108 V • 300/8 = 4.05 V (300 V base)

Synchronism-Check Elements

Enable the two single-phase synchronism-check elements by making the enable setting:

E25 := **Y**

Synchronism check is performed with the voltages connected to voltage terminals V1Y and NY, and V1Z and NZ (see *Figure 2.5*, *Figure 2.9*, *Figure 2.42*, and *Table 9.9*). In this synchronism-check subsection, these voltages are referred to as the following:

V_P and V_S

Global setting FSELECT selects which voltage functions as V_P (and by default, which functions as V_S), as shown in *Table 4.13*.

Table 4.13   Voltages V_P and V_S for Synchronism Check

Global Setting FSELECT :=	VP = Voltage connected to voltage terminals:	VS = Voltage connected to voltage terminals:
VY	V1Y, NY	V1Z, NZ
VZ	V1Z, NZ	V1Y, NY

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The two synchronism-check elements use the same voltage window (to ensure healthy voltage) and slip frequency settings (see *Figure 4.30*). They have separate angle settings (see *Figure 4.31*).

If voltages V_P and V_S are static (not slipping with respect to one another) or the breaker close time setting TCLOSD := 0.00, the two synchronism-check elements operate as shown in the top of *Figure 4.31*. The angle settings are checked for synchronism-check closing.

If voltages V_P and V_S are not static (slipping with respect to one another) the two synchronism-check elements operate as shown in the bottom of *Figure 4.31*. The angle difference is compensated by breaker close time, and the breaker is ideally closed at a zero degree phase angle difference to minimize system shock.

These synchronism-check elements are explained in detail in the following text.

Setting SYNCP

Sometimes synchronism-check voltage V_S cannot be in phase with voltage V_P. This happens in applications where any of the following are true:

➤ Phase-to-phase voltage is connected to one voltage input and phase-to-neutral voltage is connected to the other voltage input.

➤ The voltage inputs are connected to different phases.

➤ One of the voltage inputs is connected beyond a delta-wye transformer.

For such applications requiring V_S to be at a constant phase angle difference from V_P, an angle setting is made with the SYNCP setting (see *Table 4.14*). The angle setting choices (0, 30, …, 300, or 330 degrees) for setting SYNCP are referenced to V_P, and they indicate how many degrees V_S constantly lags V_P.

System Rotation Can Affect Setting SYNCP

If system rotation is ABC and V_P is connected to Phase A and V_S is connected to Phase B, then SYNCP := 120 (V_S lags V_P by 120 degrees). If voltage input connections are the same, but system rotation is ACB, then setting SYNCP := 240 degrees (V_S constantly lags V_P by 240°). See the SEL Application Guide *AG2002-02, Compensate for Constant Phase Angle Difference in Synchronism Check with the SEL-351 Relay Family* for more information on setting SYNCP with an angle setting. This guide is still generally applicable to the SEL-651R-2.

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Synchronism-Check Elements Settings

Table 4.14 Synchronism-Check Elements Settings and Settings Ranges

Setting	Definition	Range
25VPLO	Low voltage threshold for "healthy V_P voltage" window	12.50–300.00 V sec
25VPHI	High voltage threshold for "healthy V_P voltage" window	12.50–300.00 V sec
25VSLO	Low voltage threshold for "healthy V_S voltage" window	12.50–300.00 V sec
25VSHI	High voltage threshold for "healthy V_S voltage" window	12.50–300.00 V sec
25SF	Maximum slip frequency	0.005–0.500 Hz
25ANG1	Synchronism-check element 25A1 maximum angle	0° to 80°
25ANG2	Synchronism-check element 25A2 maximum angle	0° to 80°
SYNCP	The number of degrees that synchronism-check voltage V_S constantly lags voltage V_P	0° to 330°, in 30° steps
TCLOSD	Breaker close time for angle compensation	0.00–60.00 cycles when NFREQ = 60 0.00–50.00 cycles when NFREQ = 50
BSYNCH	SELOGIC control equation block synchronism-check setting	Relay Word bits referenced in *Table F.1*

Accuracy

See *Specifications on page 1.9*.
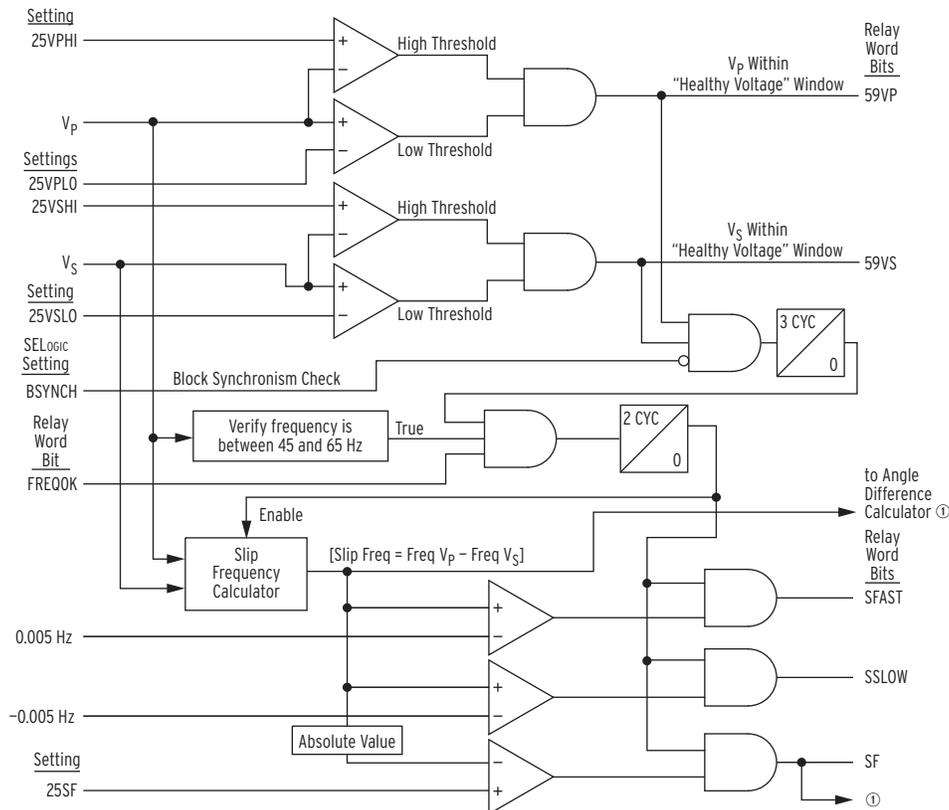
① See bottom of Figure 4.31.

Figure 4.30 Synchronism-Check Voltage Window and Slip Frequency Elements

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Synchronism-Check Elements Operation

Refer to *Figure 4.30* and *Figure 4.31*.

Voltage Window

Refer to *Figure 4.30*.

Single-phase voltage inputs VP and VS are compared to voltage windows, to verify that the voltages are "healthy" and lie within settable voltage limits. If both voltages are within their respective voltage windows, the following Relay Word bits assert:

59VP   indicates that voltage V_P is within voltage window setting limits 25VPLO and 25VPHI

59VS   indicates that voltage V_S is within voltage window setting limits 25VSLO and 25VSHI
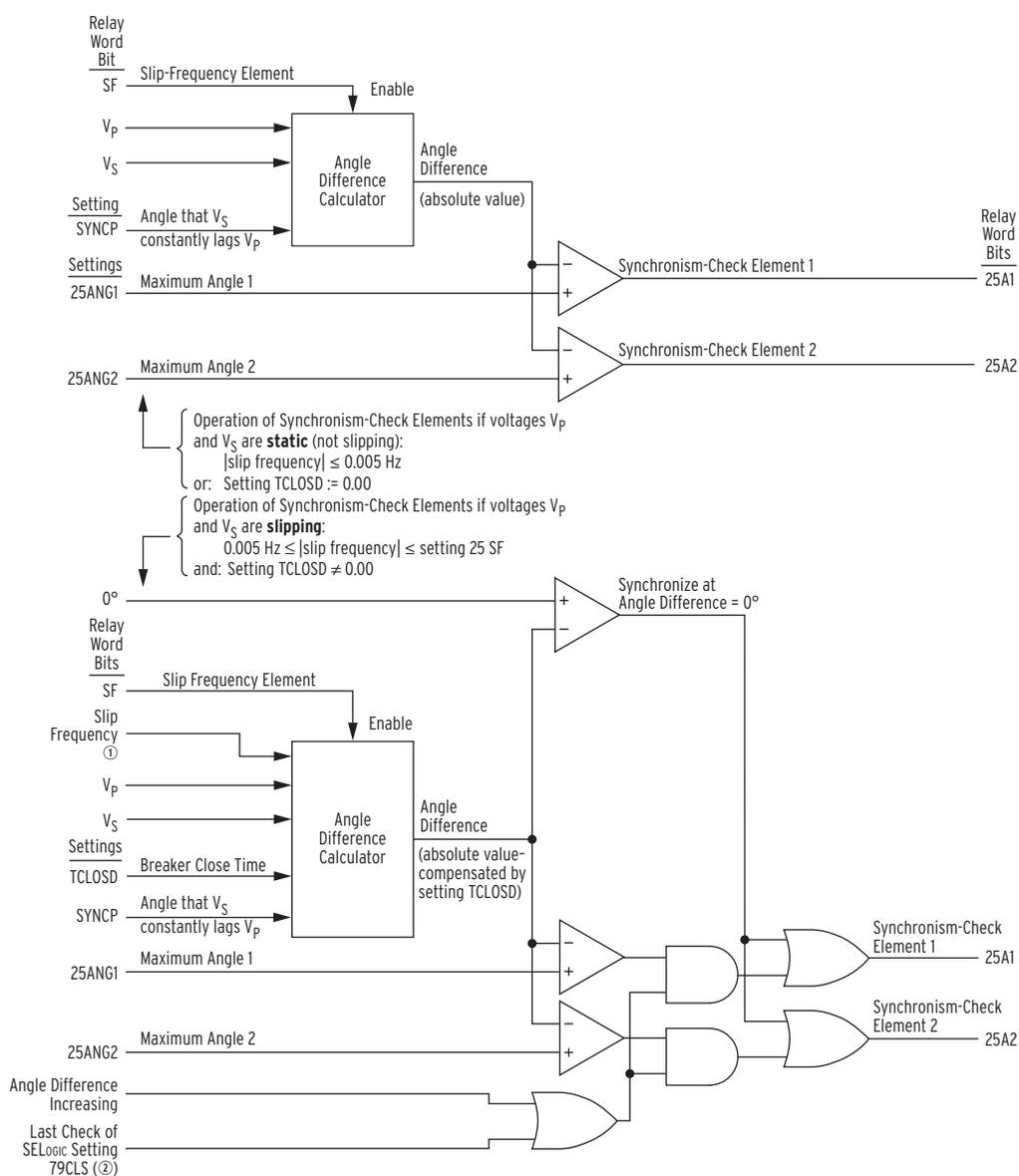
① From Figure 4.30; ② see Figure 6.7.

Figure 4.31   Synchronism-Check Elements

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Other Uses for Voltage Window Elements

If voltage limits 25VPLO/25VPHI and 25VSLO/25VSHI are applicable to other control schemes, Relay Word bits 59VP and 59VS can be used in other logic at the same time they are used in the synchronism-check logic.

If synchronism check is not being used, Relay Word bits 59VP and 59VS can still be used in other logic, with the voltage limit settings set as desired. Enable the synchronism-check logic (setting E25 := Y) and make settings 25VPLO/25VPHI and 25VSLO/25VSHI. Apply Relay Word bits 59VP and 59VS in the desired logic scheme, using SELOGIC control equations. Even though synchronism-check logic is enabled, the synchronism-check logic outputs (Relay Word bits SF, 25A1, and 25A2) do not need to be used.

Block Synchronism-Check Conditions

Refer to *Figure 4.30.*

The synchronism-check element slip frequency calculator runs if both voltages V_P and V_S are healthy (59VP and 59VS asserted to logical 1) and the SELOGIC control equation setting BSYNCH (Block Synchronism Check) is deasserted (= logical 0). Setting BSYNCH is most commonly set to block synchronism-check operation when the circuit breaker is closed (synchronism check is only needed when the circuit breaker is open):

> BSYNCH := **52A3P** see *Figure 6.2*

In addition, synchronism-check operation can be blocked when the relay is tripping:

> BSYNCH := **... OR TRIP3P**

Slip Frequency Calculator

Refer to *Figure 4.30.*

The synchronism-check element Slip Frequency Calculator in *Figure 4.30* runs if voltages V_P and V_S are healthy (59VP and 59VS asserted to logical 1) and the SELOGIC control equation setting BSYNCH (Block Synchronism Check) is deasserted (= logical 0). The Slip Frequency Calculator output is:

> Slip Frequency = $f_P - f_S$ (in units of Hz = slip cycles/second)
>
> f_P = frequency of voltage V_P (in units of Hz = cycles/second)
>
> f_S = frequency of voltage V_S (in units of Hz = cycles/second)

A complete slip cycle is one single 360-degree revolution of one voltage (e.g., V_S) by another voltage (e.g., V_P). Both voltages are thought of as revolving phasor-wise, so the "slipping" of V_S past V_P is the relative revolving of V_S past V_P.

For example, in *Figure 4.30*, if voltage V_P has a frequency of 59.95 Hz and voltage V_S has a frequency of 60.05 Hz, the difference between them is the slip frequency:

> Slip Frequency = 59.95 Hz – 60.05 Hz = –0.10 Hz = –0.10 slip cycles/second

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The slip frequency in this example is negative, indicating that voltage V_S is not "slipping" behind voltage V_P, but is in fact "slipping" ahead of voltage V_P. In a time period of one second, the angular distance between voltage V_P and voltage V_S changes by 0.10 slip cycles, which translates into:

0.10 slip cycles/second • (360°/slip cycle) • 1 second = 36°

Thus, in a time period of one second, the angular distance between voltage V_P and voltage V_S changes by 36 degrees.

The absolute value of the Slip Frequency output is run through a comparator and if the slip frequency is less than the maximum slip frequency setting, 25SF, Relay Word bit SF asserts to logical 1.

The SF Relay Word bit may not operate if the VP frequency is changing too quickly. This will not be an issue when the synchronism-check elements are being used to verify phase alignment across breakers in transmission systems with multiple paths. However, if one side of the circuit breaker is expected to vary in frequency (perhaps it is connected to a generator bus), the best configuration for using the synchronism-check element is to connect the VP terminals to the more stable system (e.g., the power grid) while the VS terminals are connected to the machine.

Generator Application for SSLOW and SFAST

Relay Word bits SSLOW and SFAST in *Figure 4.30* indicate the relative slip of voltages V_P and V_S.

The SFAST, SSLOW, and SF operation over various slip frequencies is summarized in *Table 4.15* and *Figure 4.32*.

Table 4.15   SSLOW and SFAST Relay Word Bit Operating Range

Slip Frequency Range	Relay Word Bit SSLOW	Relay Word Bit SFAST
$(f_P–f_S) < –0.005$ Hz	logical 1	logical 0
$–0.005 < (f_P–f_S) < 0.005$	logical 0	logical 0
$(f_P–f_S) > 0.005$ Hz	logical 0	logical 1

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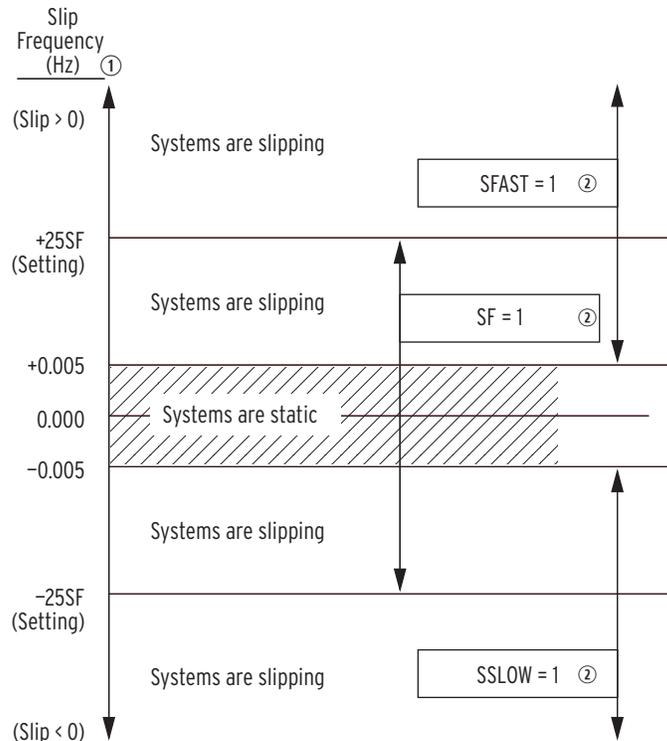
① Slip Frequency = Frequency of **VP** signal−Frequency of **VS** signal; ② from Figure 4.30.

Figure 4.32   Graphical Depiction of SFAST, SSLOW, and SF Operation Range

An application idea for SSLOW and SFAST is a small generator installation.

> With some logic (perhaps to create pulsing signals), SSLOW and SFAST might be used as signals (via output contacts) to the generator governor. SSLOW indicates that the V_P frequency is lower than the V_S frequency, while SFAST indicates that the V_P frequency is higher than the V_S frequency. If the enable into the slip frequency calculator in *Figure 4.30* is disabled (e.g., SELOGIC setting BSYNCH asserts because the breaker closes; BSYNCH = 52A3P OR …), then both SSLOW = logical 0 and SFAST = logical 0, regardless of slip frequency.

The SEL-651R-2 SSLOW and SFAST outputs are available over a larger slip frequency range than the synchronism-check element and are independent of the SF Relay Word bit. If the slip frequency is greater than the 25SF setting, Relay Word bit SF will be deasserted (logical 0) and one of the SSLOW or SFAST Relay Word bits may operate to indicate the polarity of the slip frequency.

The SSLOW and SFAST Relay Word bits may not operate reliably if the V_P frequency is changing too quickly. The best configuration for using the SSLOW and SFAST outputs is when the voltage terminal selected by Global setting FSELECT (and thus V_P) is connected to the most stable system (e.g., the power grid), while the other terminal (V_S) is connected to the "machine" side of the circuit breaker.

Angle Difference Calculator

The synchronism-check element Angle Difference Calculator in *Figure 4.31* runs if the absolute value of slip frequency is less than the maximum slip frequency setting 25SF (Relay Word bit SF is asserted).

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Voltages V_P and V_S are "Static"

Refer to the top of *Figure 4.31*.

If the absolute value of slip frequency is less than or equal to 0.005 Hz, the Angle Difference Calculator does not take into account breaker close time—it presumes voltages V_P and V_S are "static" (not "slipping" with respect to one another). This would usually be the case for an open breaker with voltages V_P and V_S that are paralleled via some other electric path in the power system. The Angle Difference Calculator calculates the angle difference between voltages V_P and V_S:

$$\text{Angle Difference} = \left| (\angle V_P - \angle V_S) \right|$$

For example, if SYNCP := 90 (indicating V_S constantly lags $V_P = V_A$ by 90 degrees), but V_S actually lags V_A by 100 angular degrees on the power system at a given instant, the Angle Difference Calculator automatically accounts for the 90 degrees and:

$$\text{Angle Difference} = \left| (\angle V_P - \angle V_S) \right| = 10°$$

Also, if breaker close time setting TCLOSD := 0.00, the Angle Difference Calculator does not take into account breaker close time, even if the voltages V_P and V_S are "slipping" with respect to one another. Thus, synchronism-check elements 25A1 or 25A2 assert to logical 1 if the Angle Difference is less than corresponding maximum angle setting 25ANG1 or 25ANG2.

Voltages V_P and V_S are "Slipping"

Refer to bottom of *Figure 4.31*.

If the absolute value of slip frequency is greater than 0.005 Hz and breaker close time setting TCLOSD ≠ 0.00, the Angle Difference Calculator takes the breaker close time into account with breaker close time setting TCLOSD (set in cycles; see *Figure 4.33*). The Angle Difference Calculator calculates the Angle Difference between voltages V_P and V_S, compensated with the breaker close time:

$$\text{Angle Difference} = \left| (\angle V_P - \angle V_S) + \left[(f_P - f_S) \bullet \text{ TCLOSD} \bullet \left(\frac{1 \text{ second}}{\text{NFREQ}} \right) \bullet \left(\frac{360°}{\text{slip cycle}} \right) \right] \right|$$

Equation 4.4

NFREQ is the Global setting that defines the nominal system frequency as 50 or 60 Hz.

Angle Difference Example (Voltages V_p and V_S are "Slipping")

Refer to bottom of *Figure 4.31*.

For example, for a 60 Hz nominal system, if the breaker close time is 10 cycles, set TCLOSD = 10 and NFREQ = 60. Presume the slip frequency is the example slip frequency calculated previously. The Angle Difference Calculator calculates the angle difference between voltages V_P and V_S, compensated with the breaker close time as shown in *Equation 4.4*.

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Intermediate calculations:

$(f_P - f_S) = (59.95 \text{ Hz} - 60.05 \text{ Hz}) = -0.10 \text{ Hz} = -0.10 \text{ slip cycles/second}$

TCLOSD • (1 second/60 cycles) = 10 cycles • (1 second/60 cycles)
= 0.167 second

Resulting in (using *Equation 4.4*):

$$= \left| (\angle V_P - \angle V_S) + [-0.10 \bullet \ 0.167 \bullet \ 360°] \right|$$
$$= \left| (\angle V_P - \angle V_S) - 6° \right|$$

NOTE: The angle compensation in Figure 4.33 appears much greater than six degrees. Figure 4.33 is for general illustrative purposes only.

During the breaker close time (TCLOSD), the voltage angle difference between voltages V_P and V_S changes by six degrees. This six degree angle compensation is applied to voltage V_S, resulting in derived voltage V_S*, as shown in *Figure 4.33*.

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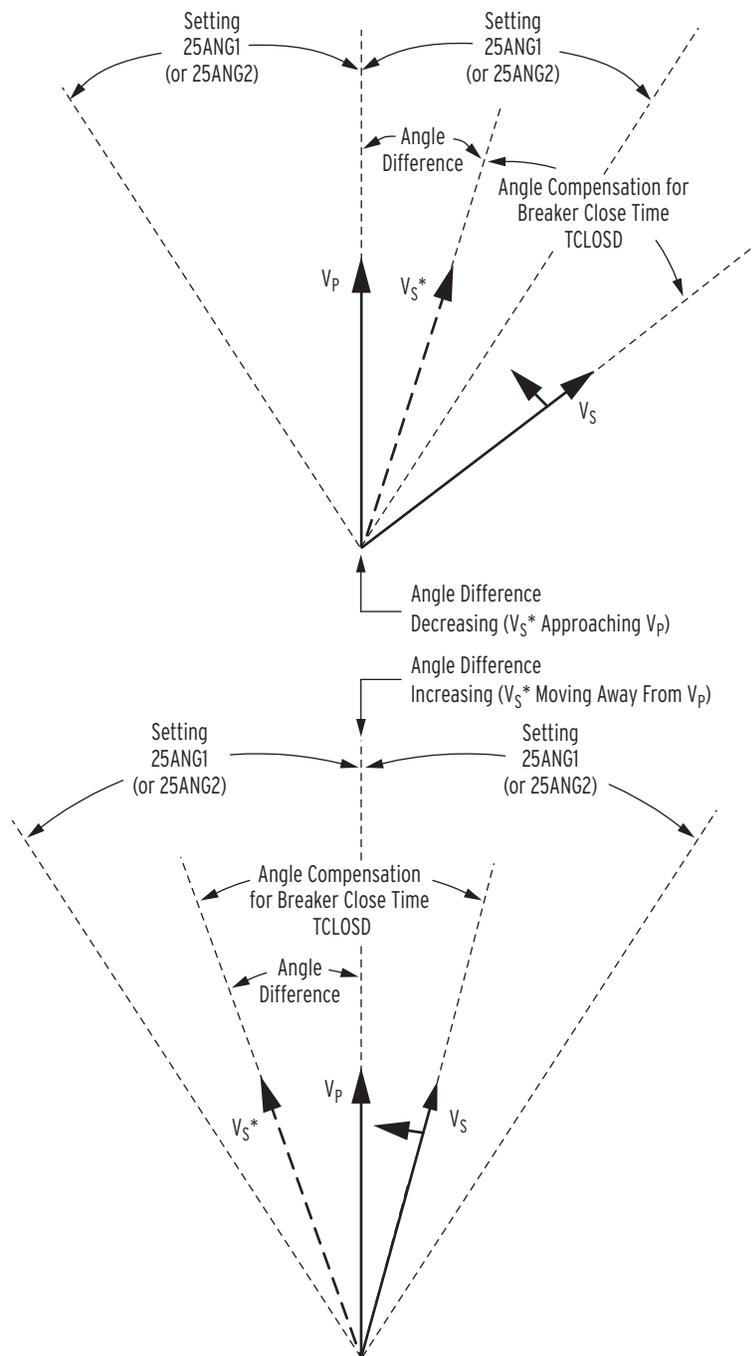
Figure 4.33   Angle Difference Between V_P and V_S Compensated by Breaker Close Time ($f_P < f_S$ and V_P Shown as Reference in This Example)

The top of *Figure 4.33* shows the Angle Difference *decreasing*—V_S^* is approaching V_P. Ideally, circuit breaker closing is initiated when V_S^* is in phase with V_P (Angle Difference = 0 degrees). Then when the circuit breaker main contacts finally close, V_S is in phase with V_P, minimizing system shock.

The bottom of *Figure 4.33* shows the Angle Difference *increasing*—V_S^* is moving away from V_P. Ideally, circuit breaker closing is initiated when V_S^* is in phase with V_P (Angle Difference = 0 degrees). Then when the circuit breaker main contacts finally close, V_S is in phase with V_P. But in this case,

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V_S* has already moved past V_P. To initiate circuit breaker closing when V_S* is in phase with V_P (Angle Difference = 0 degrees), V_S* has to slip around another revolution, relative to V_P.

Synchronism-Check Element Outputs

Synchronism-check element outputs (Relay Word bits 25A1 and 25A2 in *Figure 4.31*) assert to logical 1 for the conditions explained in the following text.

Voltages V_P and V_S are "Static" or Setting TCLOSD := 0.00

Refer to top of *Figure 4.31*.

If V_P and V_S are "static" (not "slipping" with respect to one another), the Angle Difference between them remains constant—it is not possible to close the circuit breaker at an ideal zero degree phase angle difference. Thus, synchronism-check elements 25A1 or 25A2 assert to logical 1 if the Angle Difference is less than corresponding maximum angle setting 25ANG1 or 25ANG2.

Also, if breaker close time setting (TCLOSD := 0.00), the Angle Difference Calculator does not take into account breaker close time, even if the voltages V_P and V_S are "slipping" with respect to one another. Thus, synchronism-check elements 25A1 or 25A2 assert to logical 1 if the Angle Difference is less than corresponding maximum angle setting 25ANG1 or 25ANG2.

Voltages V_P and V_S are "Slipping" and Setting TCLOSD $\neq$ 0.00

Refer to bottom of *Figure 4.31*. If V_P and V_S are "slipping" with respect to one another and breaker close time setting TCLOSD $\neq$ 0.00, the Angle Difference (compensated by breaker close time TCLOSD) changes through time. Synchronism-check element 25A1 or 25A2 asserts to logical 1 for any one of the following three scenarios.

1. The top of *Figure 4.33* shows the Angle Difference *decreasing*—V_S* is approaching V_P. When V_S* is in phase with V_P (Angle Difference = 0 degrees), synchronism-check elements 25A1 and 25A2 assert to logical 1.

2. The bottom of *Figure 4.33* shows the Angle Difference *increasing*—V_S* is moving away from V_P. V_S* was in phase with V_P (Angle Difference = 0 degrees), but has now moved past V_P. If the Angle Difference is *increasing*, but the Angle Difference is still less than maximum angle settings 25ANG1 or 25ANG2, then corresponding synchronism-check elements 25A1 or 25A2 assert to logical 1.

   In this scenario of the Angle Difference increasing, but still being less than maximum angle settings 25ANG1 or 25ANG2, the operation of corresponding synchronism-check elements 25A1 and 25A2 becomes *less restrictive*. Synchronism-check breaker closing does not have to wait for voltage V_S* to slip around again in phase with V_P (Angle Difference = 0 degrees). There might not be enough time to wait for this to happen. Thus, the "Angle Difference = 0 degrees" restriction is eased for this scenario.

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NOTE: In scenario 3, concerning reclose supervision, SELOGIC control equation setting 79CLS3P (reclose supervision for three-phase reclosing) is used. The logic discussed in scenario 3 is equally applicable to reclose supervision settings 79CLSA, 79CLSB, and 79CLSC if single-pole reclosing is enabled (Group setting ESPB := Y).

3. Refer to *Reclose Supervision Logic on page 6.10*.

Refer to the bottom of *Figure 6.6*. If timer 79CLSD is set greater than zero (e.g., 79CLSD := 60.00 cycles) and it times out without SELOGIC control equation setting 79CLS3P (Reclose Supervision) asserting to logical 1, the relay goes to the Lockout State (see top of *Figure 6.7*).

Refer to the top of *Figure 6.6*. If timer 79CLSD is set to zero (79CLSD := 0.00), SELOGIC control equation setting 79CLS3P (Reclose Supervision) is checked only once to see if it is asserted to logical 1. If it is not asserted to logical 1, the relay goes to the Lockout State.

Refer to the top of *Figure 4.33*. Ideally, circuit breaker closing is initiated when V_S^* is in phase with V_P (Angle Difference = 0 degrees). Then when the circuit breaker main contacts finally close, V_S is in-phase with V_P, minimizing system shock. But with time limitations imposed by timer 79CLSD, this may not be possible. To try to avoid going to the Lockout State, the following logic is employed:

If 79CLS3P has not asserted to logical 1 while timer 79CLSD is timing (or timer 79CLSD is set to zero and only one check of 79CLS3P is made), the synchronism-check logic at the bottom of *Figure 4.31* becomes *less restrictive* at the "instant" timer 79CLSD is going to time out (or make the single check). It drops the requirement of waiting until the *decreasing* Angle Difference (V_S^* approaching V_P) brings V_S^* in phase with V_P (Angle Difference = 0 degrees). Instead, it just checks to see that the Angle Difference is less than angle settings 25ANG1 or 25ANG2.

If the Angle Difference is less than angle setting 25ANG1 or 25ANG2, then the corresponding Relay Word bit, 25A1 or 25A2, asserts to logical 1 for that "instant" (asserts for 1/4 cycle).

For example, if SELOGIC control equation setting 79CLS3P (Reclose Supervision) is set as follows:

79CLS3P := **(25A1 OR ...) AND ...**

and the angle difference is less than angle setting 25ANG1 at that "instant," setting 79CLS3P asserts to logical 1 for 1/4 cycle, allowing the sealed-in open interval time-out to propagate to the close logic in *Figure 6.3*. Element 25A2 operates similarly. The AND is used in the example to include hardware requirements for reclosing. For example, AND TCCAP can be included to indicate sufficient stored energy for trips/reclosures.

Synchronism-Check Applications for Automatic Reclosing and Manual Closing

Refer to *Close Logic on page 6.5* and *Reclose Supervision Logic on page 6.10*.

For example, set 25ANG1 := 15 degrees and use the resultant synchronism-check element in the reclosing relay logic to supervise automatic reclosing:

79CLS3P := **(25A1 OR ...) AND ...** see *Figure 6.6*

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Set 25ANG2 := 25 degrees and use the resultant synchronism-check element in manual close logic to supervise manual closing (e.g., assert IN106 to initiate manual close):

> SV01 := **(R_TRIG IN106 or CC3) AND NOT TRIP3P OR SV01 AND NOT SV01T AND NOT TRIP3P AND NOT CLOSE3P**

> CL3P := **SV01 AND (25A2 OR ...)** see *Figure 6.3*

Set SV01PU := *n* cycles and SV01DO := 0.00 cycles. Choose *n* to represent the maximum period that a manual close may be attempted. A typical setting for *n* might be 50 to 600 cycles (approximately 1 to 10 seconds).

The timer effectively stretches the one processing interval CC3 pulse (asserted by the **CLOSE** command or via DNP3, Modbus, or SEL Fast Operate protocols—see *Section 10: Communications*) to improve the chances of closing if the synchronism-check element is not asserted at the instant the command is received. Other possible inputs to initiate manual closing include using a local bit (R_TRIG LB*n*), remote bit (R_TRIG RB*n*), or programmable operator control bit (PB*n*).

The rising edge operator "R_TRIG" on IN106 prevents a maintained assertion to logical 1 from creating a standing close condition. The NOT TRIP3P term defeats the manual close window if a relay trip is detected. The NOT CLOSE3P term cancels the timing once the close logic is activated. Other conditions could be added to defeat the manual close.

In this example, the angular difference across the circuit breaker can be greater for a manual close (25 degrees) than for an automatic reclose (15 degrees).

A single output contact (e.g., OUT102 := CLOSE3P) can provide the close function for both automatic reclosing and manual closing (see *Figure 6.1* logic output).

Frequency Elements

Six frequency elements are available. Enable the desired number of frequency elements with the E81 enable setting:

> E81 := **N (none), 1–6**

The enable setting is shown in *Figure 4.38*. Frequency is determined from the voltage applied to the recloser control voltage terminals V1Y and NY or V1Z and NZ, as shown in *Table 4.16*.

Table 4.16   Voltage Source for Frequency Elements

Global Setting FSELECT :=	Frequency for 81 elements measured on voltage terminals:
OFF	N/A[a]
VY	V1Y, NY
VZ	V1Z, NZ

[a] When Global setting FSELECT := OFF, the SEL-651R-2 will measure the frequency for frequency tracking and metering. See Frequency Source Selection Setting (FSELECT) on page 9.33 for more information on frequency tracking. When Global setting FSELECT := OFF, the enable setting E81 is forced to N and cannot be changed.

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Frequency Element Logic Diagrams

The frequency element logic in *Figure 4.38* is controlled by the Relay Word bit 27B81, which is derived from voltage signals in one of the undervoltage block diagrams *Figure 4.34–Figure 4.37*, depending on Global settings FSELECT, and VYCONN or VZCONN.
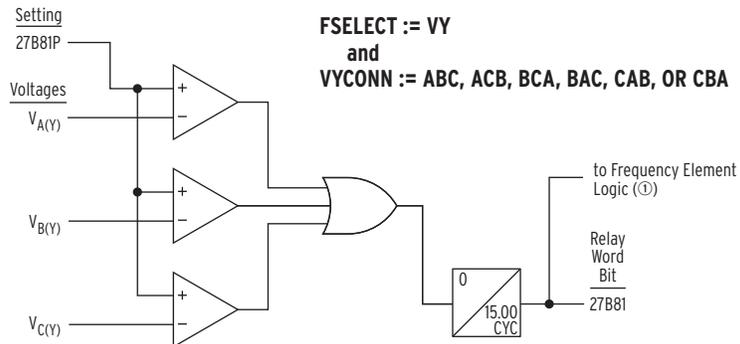
Figure 4.34 Undervoltage Block for Frequency Elements When FSELECT := VY and Three-Phase Voltage Connected
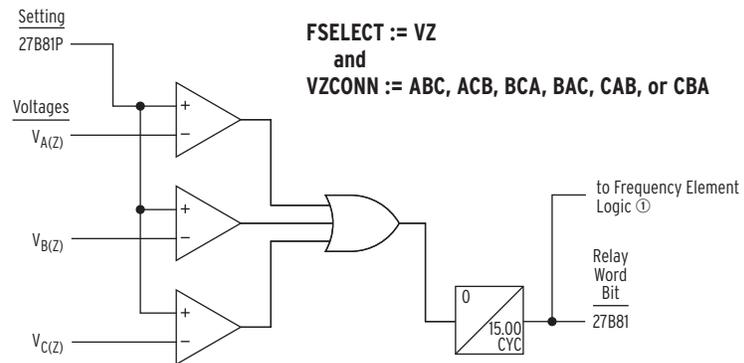
Figure 4.35 Undervoltage Block for Frequency Elements When FSELECT := VZ and Three-Phase Voltage Connected
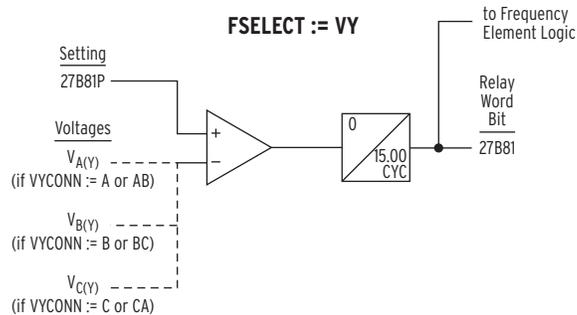
Figure 4.36 Undervoltage Block for Frequency Elements When FSELECT := VY and Single-Phase Voltage Connected

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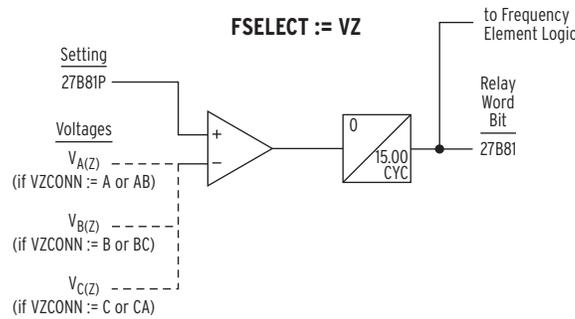
Figure 4.37 Undervoltage Block for Frequency Elements When FSELECT := VZ and Single-Phase Voltage Connected

Frequency Element Settings

Table 4.17 Frequency Elements Settings and Settings Ranges

Setting	Definition	Range
27B81P	undervoltage frequency element block (see *Figure 4.34–Figure 4.37*)	12.50–300.00 V secondary
81D1P	frequency element 1 pickup	40.00–65.00 Hz
81D1D	frequency element 1 time delay	2.00–16000.00 cycles, in 0.25-cycle steps
81D2P	frequency element 2 pickup	40.00–65.00 Hz
81D2D	frequency element 2 time delay	2.00–16000.00 cycles, in 0.25-cycle steps
81D3P	frequency element 3 pickup	40.00–65.00 Hz
81D3D	frequency element 3 time delay	2.00–16000.00 cycles, in 0.25-cycle steps
81D4P	frequency element 4 pickup	40.00–65.00 Hz
81D4D	frequency element 4 time delay	2.00–16000.00 cycles, in 0.25-cycle steps
81D5P	frequency element 5 pickup	40.00–65.00 Hz
81D5D	frequency element 5 time delay	2.00–16000.00 cycles, in 0.25-cycle steps
81D6P	frequency element 6 pickup	40.00–65.00 Hz
81D6D	frequency element 6 time delay	2.00–16000.00 cycles, in 0.25-cycle steps

Frequency element time delays are best set to no less than five cycles. Frequency is determined by a zero-crossing technique on voltage terminal VnY and NY or VnZ and NZ (where n = 1, 2, or 3). If voltage waveform offset occurs (e.g., because of a fault), then frequency may be off for a few cycles. A 5-cycle or greater time delay (e.g., 81D1D := 6.00 cycles) overrides this occurrence.

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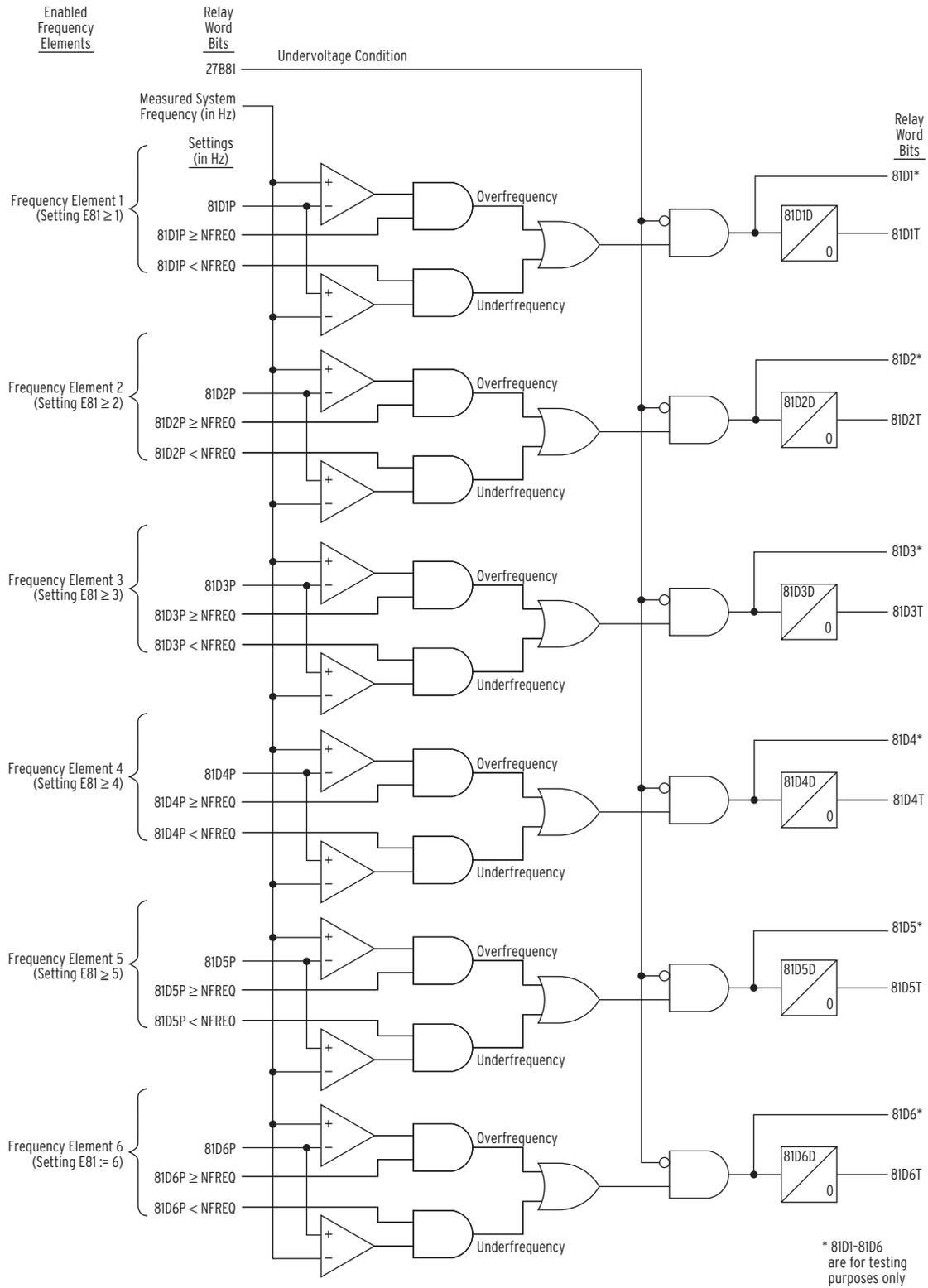
Figure 4.38 Levels 1 Through 6 Frequency Elements

Accuracy

See *Specifications on page 1.9*.

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Create Over- and Underfrequency Elements

Refer to *Figure 4.38*.

Note that pickup settings 81D1P–81D6P are compared to setting NFREQ. NFREQ is the nominal frequency setting (a global setting), set to 50 or 60 Hz.

Overfrequency Element

For example, make the following settings:

NFREQ := **60 Hz** nominal system frequency is 60 Hz

E81 ≥ **1** enable frequency element 1

81D1P := **61.25 Hz** frequency element 1 pickup

With these settings (81D1P ≥ NFREQ), the overfrequency part of frequency element 1 logic is enabled. 81D1 and 81D1T operate as overfrequency elements. 81D1 is used in testing only.

Underfrequency Element

For example, make the following settings:

NFREQ := **60 Hz** nominal system frequency is 60 Hz

E81 ≥ **2** enable frequency element 2

81D2P := **59.65 Hz** frequency element 2 pickup

With these settings (81D2P < NFREQ) the underfrequency part of frequency element 2 logic is enabled. Elements 81D2 and 81D2T operate as underfrequency elements. Setting 81D2 is used in testing only.

Frequency Element Operation

Refer to *Figure 4.38*.

Overfrequency Element Operation

With the previous overfrequency element example settings, if system frequency is less than or equal to 61.25 Hz (81D1P := 61.25 Hz), frequency element 1 outputs:

81D1 := **logical 0** instantaneous element

81D1T := **logical 0** time delayed element

If system frequency is greater than 61.25 Hz (81D1P := 61.25 Hz), frequency element 1 outputs:

81D1 := **logical 1** instantaneous element

81D2T := **logical 1** time delayed element

Relay Word bit 81D1T asserts to logical 1 only after time delay 81D1D.

Underfrequency Element Operation

With the previous underfrequency element example settings, if system frequency is less than or equal to 59.65 Hz (81D2P := 59.65 Hz), frequency element 2 outputs:

81D2 := **logical 1** instantaneous element

81D2T := **logical 1** time delayed element

Relay Word bit 81D2T asserts to logical 1 only after time delay 81D2D.

If system frequency is greater than 59.65 Hz (81D2P := 59.65 Hz), frequency element 2 outputs:

81D2 := **logical 0** instantaneous element

81D2T := **logical 0** time delayed element

Instantaneous Frequency Element Response Time

The SEL-651R-2 uses a zero-crossing period measurement technique on the voltage applied to the V1Y and NY or V1Z and NZ terminals (see *Table 4.16*) to determine the power system frequency. There is an intrinsic delay in the instantaneous frequency elements 81D1–81D6 that depends on the pickup setting, the applied signal, and the conditions prior to the change in signal.

The 81D1–81D6 response time to a valid frequency change is typically 1 to 3 cycles, but could be as long as 4.5 cycles. This detail is usually of little consequence when longer time delay settings 81D1D–81D6D are used. However, understanding this built-in delay may help during testing and in certain applications.

System disturbances that do not cause the undervoltage block element 27B81 to assert can affect the voltage signals and cause the instantaneous frequency elements to briefly assert when there is no actual frequency deviation. For this reason, time-delayed elements 81D1T–81D6T are the only Relay Word bits intended for use in protection, and the recommended minimum time-delay setting is 5 cycles.

Frequency Element Time Delay Considerations

The SEL-651R-2 frequency element time delay settings are specified in cycles, as shown in *Table 4.17*. When determining the time delay settings appropriate for an application, keep in mind that the power system frequency will not be at the nominal value (50 Hz or 60 Hz) when an overfrequency or underfrequency element times out. The relay adjusts the processing algorithms to track the system frequency, and this can make the time delay seem shorter or longer than anticipated.

For pickup settings that are close to the nominal frequency, or with short duration delays, the nominal frequency may be used to convert the desired time delay from seconds into cycles with negligible error.

However, for elements that have pickup settings (81DnP) set further from the nominal frequency, or elements set with long time delays (81DnD), the over- or underfrequency pickup setting may be used for the time-base conversion instead.

The observed time delay will depend on the frequency of the power system or test set during the excursion and whether the frequency change is applied as step-change, a ramp, or some other function.

Overfrequency Element Settings Example

On a 60 Hz nominal system, the planner requires an overfrequency trip to occur if the frequency exceeds 60.60 Hz for 30 seconds.

Convert the time delay from seconds to cycles by using the pickup setting.

$$
\begin{aligned}
\text{Delay} &= 30 \text{ s} \cdot 60.60 \text{ Hz} \\
&= 30 \text{ s} \cdot 60.60 \text{ cycles/s} \\
&= 1818 \text{ cycles}
\end{aligned}
$$

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Required settings.

> 81D1P = **60.60 Hz**
>
> 81D1D = **1818.00 cycles**

Using the example settings, if a 60.80 Hz signal is applied for testing, the SEL-651R-2 would be expected to assert 81D1T approximately

> 1818 cycles / 60.80 cycles/s = 29.90 s

after the instantaneous element (81D1) pickup.

If the nominal frequency 60 Hz conversion factor had been used instead, the time delay setting would have been 1800 cycles and the same 60.80 Hz test signal would be expected to assert 81D1T approximately 1800 cycles / 60.80 cycles/s = 29.61 s after the instantaneous element (81D1) pickup.

In this test example, the time delay settings adjustment improves the timing accuracy by about 1 percent.

Frequency Element Voltage Control

Refer to *Figure 4.34–Figure 4.38*.

Note that all six frequency elements are controlled by the same undervoltage element (Relay Word bit 27B81). For example, when Global setting FSELECT := VY and Global setting VYCONN := BAC, Relay Word bit 27B81 asserts to logical 1 and blocks the frequency element operation if any voltage ($V_{A(Y)}$, $V_{B(Y)}$, or $V_{C(Y)}$) goes below voltage pickup 27B81P. This control prevents erroneous frequency element operation following fault inception.

However, if Global setting FSELECT := VY and Global setting VYCONN := B, Relay Word bit 27B81 is affected only by the voltage applied to the V1Y and NY terminals (which is the quantity $V_{B(Y)}$; see *Figure 9.21*). This is useful in applications where there is only single-phase voltage available to the relay.

Other Uses for Undervoltage Element 27B81

If voltage pickup setting 27B81P is applicable to other control schemes, Relay Word bit 27B81 can be used in other logic at the same time it is used in the frequency element logic.

For example, in the SEL-651R-2 default settings, the torque-control equation 81RTC uses the logical inverse of 27B81, as described in *Rate-of-Change-of-Frequency (81R) Protection on page 4.57*.

If frequency elements are not being used, Relay Word bit 27B81 can still be used in other logic, with voltage setting 27B81P set as desired. Enable the frequency elements (setting E81 ≥1) and set 27B81P as desired. Apply Relay Word bit 27B81 in the desired logic scheme by using SELOGIC control equations. Even though frequency elements are enabled, the frequency element outputs (Relay Word bits 81D1T–81D6T) do not have to be used.

Frequency Element Uses

The instantaneous frequency elements (81D1–81D6) are used in testing only.

The time-delayed frequency elements (81D1T–81D6T) are used for underfrequency load shedding, frequency restoration, and other schemes.

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Underfrequency Load Shedding

For example, to implement underfrequency load shedding with time-delayed frequency element 81D1T, make the SELOGIC control equations trip setting:

TR3P := **... OR 81D1T**

Also make the following settings:

79DTL3P := **... OR 81D1T** drive-to-lockout—see *Figure 6.11* and following explanation

T11_LED := **81D1T** over- and underfrequency target LED—see *Figure 11.13* and *Table 5.3*

See the note at the end of the *Table 5.2* for background on making these two settings when making trip settings changes/modifications.

Rate-of-Change-of-Frequency (81R) Protection

Frequency changes occur in power systems when there is an unbalance between load and active power generated. Typically, generator control action adjusts the generated active power and restores the frequency to nominal value. Failure of such control action can lead to system instability unless remedial action, such as load shedding, is taken. You can use the rate-of-change-of-frequency element to detect and initiate a remedial action. The SEL-651R-2 provides four rate-of-change-of-frequency elements. *Table 4.18* shows the settings available for the elements.

Table 4.18 Rate-of-Change-of-Frequency Settings

Setting	Definition	Setting Range
E81R	Enable Rate-of-Change-of-Frequency Elements	N, 1–4
81RTC	Rate-of-Change-of-Frequency Elements Torque Control	Relay Word bits referenced in *Table F.1* or set directly to logical 1 (= 1)
81R1P	Element 1 Pickup	OFF, 0.10–15.00 Hz/sec
81R1TRND	Element 1 Trend	INC, DEC, ABS
81R1PU	Element 1 Timer Pickup	0.10–60.00 sec
81R1DO	Element 1 Timer Dropout	0.00–60.00 sec
81R2P	Element 2 Pickup	OFF, 0.10–15.00 Hz/sec
81R2TRND	Element 2 Trend	INC, DEC, ABS
81R2PU	Element 2 Timer Pickup	0.10–60.00 sec
81R2DO	Element 2 Timer Dropout	0.00–60.00 sec
81R3P	Element 3 Pickup	OFF, 0.10–15.00 Hz/sec
81R3TRND	Element 3 Trend	INC, DEC, ABS
81R3PU	Element 3 Timer Pickup	0.10–60.00 sec
81R3DO	Element 3 Timer Dropout	0.00–60.00 sec
81R4P	Element 4 Pickup	OFF, 0.10–15.00 Hz/sec
81R4TRND	Element 4 Trend	INC, DEC, ABS
81R4PU	Element 4 Timer Pickup	0.10–60.00 sec
81R4DO	Element 4 Timer Dropout	0.00–60.00 sec

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NOTE: The SEL-651R-2 measures the system frequency from the voltage input defined by the FSELECT setting. See Table 4.16 for related details.

Use E81R setting to enable the desired number of the elements. *Figure 4.39* shows the element logic. The SEL-651R-2 measures frequency (mf1), and then measures a second frequency (mf2) after a time window (dt) determined by the Trip Level setting (81RnP). The element has hysteresis, such that pickup is 100 percent of the 81RnP setting and dropout is 95 percent. *Table 4.19* shows the time windows for different trip level settings. The Relay Word bit 81RT = 81R1T OR 81R2T OR 81R3T OR 81R4T.

The SEL-651R-2 does not track the system frequency when the frequency changes faster than 20 Hz/second, and the 81R elements will not respond.
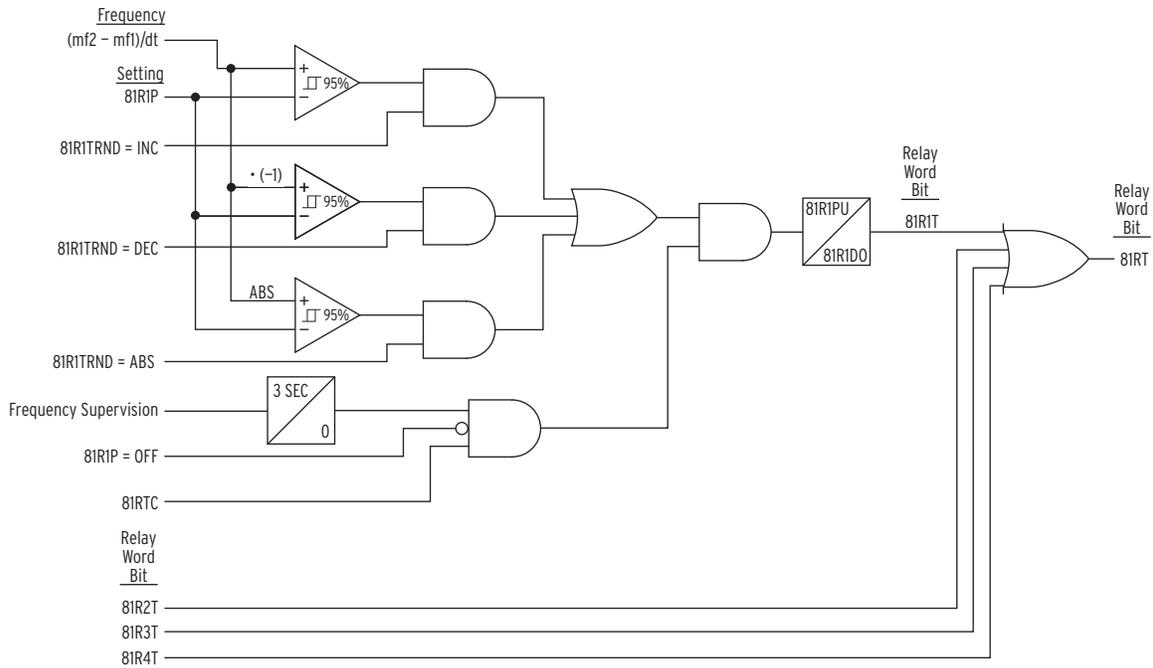
Logic shown for 81R1T. Logic for 81R2T–81R4T is similar.

Figure 4.39   81R Frequency Rate-of-Change Scheme Logic

Table 4.19   Time Window Versus 81RnP Setting

81RnP Setting (Hz/s)	Time Window (ms)
0.10–0.14	1000
0.15–0.19	666
0.20–0.29	500
0.30–0.39	333
0.40–0.59	250
0.60–1.19	166
1.20–2.39	83
2.40–15.00	41

For testing purposes, the expected pickup time can be calculated by using *Equation 4.5*, the 81RnP pickup setting, the corresponding time window from *Table 4.19*, and the rate-of-change-of-frequency of the applied signal. For a given 81RnP pickup setting, the pickup time of the element decreases as the rate of frequency change increases. Use *Equation 4.5* to select the time delay setting 81RnPU so that the element responds as desired.

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$$81\mathrm{R}n\mathrm{T}\ \text{Minimum Pickup Time}\ =\ \frac{81\mathrm{R}n\mathrm{P} \bullet\ \text{Time Window}}{\text{Rate of Frequency Change}} + 81\mathrm{R}n\mathrm{PU}$$

Equation 4.5

Set 81R*n* Trend to INC or DEC to limit operation of the element to increasing or decreasing frequency respectively. Set the trend to ABS if you want the element to disregard the frequency trend.

Frequency supervision ensures that the frequency measurement is valid, is between 40 and 70 Hz, and is being measured from the voltage V1Y or V1Z channel, according to the FSELECT setting.

Set 81RTC to limit when the 81R elements are active. The default setting is shown below:

81RTC := **NOT 27B81**

Relay Word bit 27B81 asserts when any of the phase voltages fall below the 27B81P threshold. By default, 27B81P is set to 80.00 V. As a result, when configured with default settings, the 81RTC SELOGIC control equation operates as an undervoltage supervision check for the 81R elements. This supervision is important because it prevents the elements from operating during a fault condition where the system frequency may not be measured accurately. The 27B81P pickup setting should be set so that it asserts for fault conditions. Frequency elements must be enabled to modify 27B81P; if no frequency elements are enabled, then 27B81P is set to its default value of 80.00 V.

Use the Relay Word bit 81R*n*T or 81RT in the SELOGIC trip equations to open appropriate breaker(s) as required by your load shedding scheme.

Voltage Sag, Swell, and Interruption Elements

The SEL-651R-2 has three types of elements to detect voltage disturbances. These elements detect voltage sags, swells, and interruptions (abbreviated as VSSI or SSI). These elements are enabled by Group setting ESSI := Y and controlled by the VINT, VSWELL, and VSAG settings.

The SEL-651R-2 VSSI elements monitor and respond to the three-phase voltages connected to either the VY- or VZ-voltage terminals, as designated by Global setting VSELECT := VY or VZ. If Global setting VSELECT := OFF, enable setting ESSI is forced to N and cannot be changed.

Enter the VSSI element threshold settings VSAG, VSWELL, and VINT in percentage units, which relate to the Positive-Sequence Reference Voltage: Vbase. The use of percentage settings instead of absolute voltage limits allows the SSI elements to perform better in systems that have a range of nominal voltages, with no need to adjust settings for seasonal loading or to set them far apart to accommodate the action of a tap-changing transformer. The SSI elements respond to phase-to-neutral voltages.

The Positive-Sequence Reference Voltage is discussed in its own subsection.

The Voltage Sag, Swell, Interruption Recorder automatically uses the SSI elements. These elements are also available as Relay Word bits, so they can be used in any SELOGIC control equation (see *Sag/Swell/Interruption (SSI) Report on page 12.42*).

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Voltage Sag Elements

As shown in *Figure 4.40*, if the magnitude of a voltage drops below the voltage sag pickup threshold for one cycle, the corresponding SAG Relay Word bit for that phase asserts (SAGA, SAGB, or SAGC). If all three SAG*p* elements assert, an additional Relay Word bit asserts—SAG3P. The SAG*p* elements remain asserted until the magnitude of the corresponding voltage rises and remains above the sag dropout threshold for one cycle.

The sag pickup and dropout thresholds depend on Vbase and the VSAG setting.
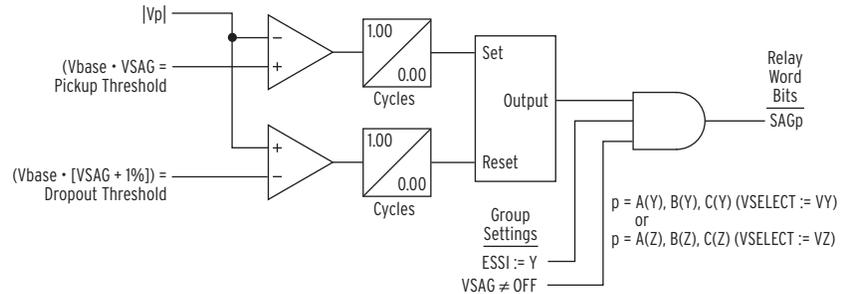
Figure 4.40   Voltage Sag Elements

Voltage Swell Elements

As shown in *Figure 4.41*, if the magnitude of a voltage rises above the voltage swell pickup threshold for one cycle, the corresponding SW Relay Word bit for that phase asserts (SWA, SWB, or SWC). If all three SW*p* elements assert, an additional Relay Word bit asserts—SW3P. The SW*p* elements remain asserted until the magnitude of the corresponding voltage drops and remains below the swell dropout threshold for one cycle.

The swell pickup and dropout thresholds depend on Vbase and the VSWELL setting.
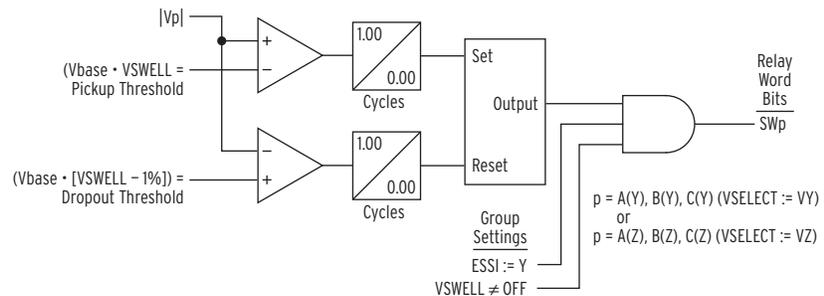
Figure 4.41   Voltage Swell Elements

Voltage Interruption Elements

As shown in *Figure 4.42*, if the magnitude of a voltage drops below the voltage interruption pickup threshold for one cycle, the corresponding INT Relay Word bit for that phase asserts (INTA, INTB, or INTC). If all three INT*p* elements assert, an additional Relay Word bit asserts—INT3P. The INT*p* elements remain asserted until the magnitude of the corresponding voltage rises and remains above the interruption dropout threshold for one cycle.

The interruption pickup and dropout thresholds depend on Vbase and the VINT setting.

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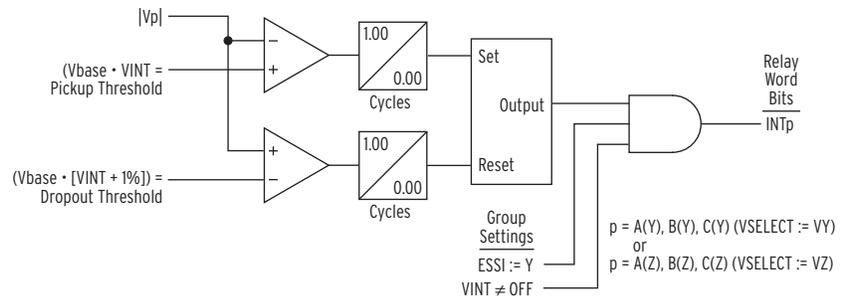
Figure 4.42   Voltage Interruption Elements

Voltage Sag, Swell, and Interruption Elements Settings

The settings ranges for the SSI thresholds are shown in *Table 4.20*.

The factory-default settings match the Interruption, Sag, and Swell definitions in IEEE Std 1159-1995, Classifications of RMS Variations.

**Table 4.20   Sag/Swell/Interruption Elements Settings
(Must First Set ESSI := Y)**

Settings	Definition	Range	Default
VINT[a]	Percentage of memory voltage compared to phase-to-neutral voltage to assert INT elements	OFF, 5 to 95 percent of reference voltage, Vbase	10.00%
VSAG	Percentage of memory voltage compared to phase-to-neutral voltage to assert SAG elements	OFF, 10 to 95 percent of reference voltage, Vbase	90.00%
VSWELL	Percentage of memory voltage compared to phase-to-neutral voltage to assert SW elements	OFF, 105 to 180 percent of reference voltage, Vbase (300 V secondary maximum upper limit)	110.00%

[a] VINT cannot be set higher than VSAG

Positive-Sequence Reference Voltage, Vbase

The relay converts the positive-sequence voltage quantity, $|V1|$, to a reference voltage, Vbase, which has a thermal demand characteristic with a time constant of 100 seconds. This allows the Vbase quantity to slowly track normal system voltage variations (tap changer operations and load effects), but not follow fast system voltage changes (unless the change is held for several seconds).

The $|V1|$ quantity for Vbase is obtained from the voltage terminals selected by the Global setting VSELECT := VY or VZ.

In a balanced three-phase system, $|V1|$ is the average of the three phase-to-neutral voltages.

Vbase tracks $|V1|$, and represents the average phase-to-neutral voltage.

The present value of Vbase can be viewed by issuing the **MET** command (see *MET Command (Metering Data) on page 10.57*).

Vbase Thermal Element Block

To prevent the Vbase quantity from tracking during transient voltage conditions, the calculation of the Vbase thermal element is blocked during the assertion of any of the SAG*p*, SW*p*, or INT*p* Relay Word bits or the SSI_TRIG or FAULT SELOGIC control equation settings. When blocked, the Vbase quantity will not change. This allows the SAG, SWELL, and INT

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elements voltage comparisons to be made with the reference Vbase locked at a "healthy" system voltage level. Once the disturbance is over and all of the SAG*p*, SW*p*, and INT*p* Relay Word bits and the FAULT SELOGIC control equation setting deassert, the thermal element for Vbase is unblocked.

Figure 4.43 shows an example of how Vbase tracking is suspended during a voltage disturbance. The example voltage disturbance is the result of an overload condition (three-phase sag), followed by a source-side breaker operation (three-phase interruption). To illustrate the dynamic nature of the VSSI thresholds, the Interrupt, Sag, and Swell pickup levels are also plotted with the factory-default settings for VINT, VSAG, and VSWELL. For this hypothetical three-phase disturbance, V1 has the same magnitude as V_A, V_B, and V_C (as shown). Single-phase disturbances are handled in a similar fashion, except that the phases and V1 will have different voltage magnitudes.

The use of a VSAG setting higher than 90 percent, at the same time as a VSWELL setting lower than 110 percent, should be carefully considered. Moving these thresholds too close together increases the probability that an end of disturbance condition is missed. This could create a false sag or swell condition that may not clear itself until the next disturbance, thus causing the Vbase thermal element to remain blocked.

The SSI_TRIG SELOGIC is described in *SSI Triggering and Recording on page 12.42*.

Vbase thermal element blocking by the FAULT Relay Word bit is programmable via SELOGIC setting FAULT. The FAULT Relay Word bit also controls other relay functions; see subsection *SELOGIC Control Equation Setting FAULT on page 5.18*.
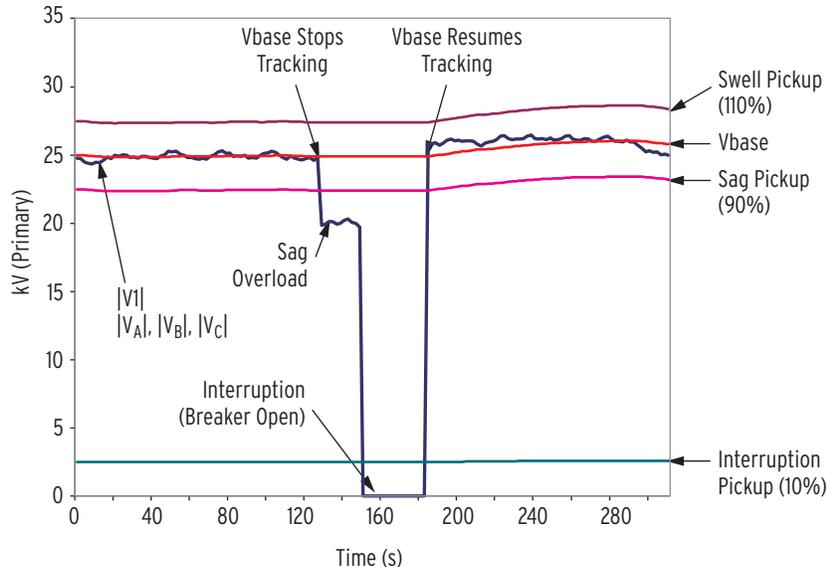
Figure 4.43   Vbase Tracking Example (Three-Phase Disturbance)

Vbase Initialization

The Vbase thermal element is automatically initialized when the relay is powered up, and also after a settings change or group change that results in a new ESSI := Y condition.

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You can also force Vbase to initialize by issuing the **SSI R** command (Access Level 1—see *SSI Command (Voltage Sag/Swell/Interruption Report) on page 10.69*).

During initialization, the SSI elements are deasserted and the SSI Recorder is disabled until all of the following conditions are met (for Y-terminal voltages when Global setting VSELECT := VY, or Z-terminal voltages when VSELECT := VZ):

➤ $|V1| > |3V2|$ (correct phase rotation check)

➤ $|V1| > |3V0|$ (correct phase connection check)

➤ V_A, V_B, V_C are all greater than 25 V secondary

➤ SELOGIC control equation setting FAULT is deasserted

➤ $|V1|$ is within three percent of the calculated Vbase value

➤ At least twelve seconds have elapsed

As soon as the above Vbase initialization conditions are satisfied, the SSI Relay Word bits will be allowed to change state according to their settings and the present voltage conditions, and the SSI Recorder will be enabled.

Vbase Tracking Range

The Vbase quantity will track the positive-sequence voltage over a large range of system voltages. The tracking limits are explained below. In normal relay use, these limits are not likely to be reached, because one of the Sag, Swell, or Interruption Relay Word bits would most likely assert for a large voltage deviation, thus blocking the Vbase thermal element from tracking to one of the range limits.

The minimum value that Vbase can achieve is equivalent to a positive-sequence (V1) value of 25 volts secondary. In primary units, the lowest value is the following:

When VSELECT := VY, minimum Vbase $= \dfrac{25V \cdot PTRY}{1000}$ kV.

Equation 4.6

> **NOTE:** If the SEL-651R-2 is ordered with LEA ac inputs on the VY terminals, Equation 4.6 still applies, provided that the PTRY setting is properly scaled—see PT Ratio Setting Adjustments on page 9.42.

When VSELECT := VZ, minimum Vbase $= \dfrac{25V \cdot PTRZ}{1000}$ kV.

Equation 4.7

The maximum value that Vbase can achieve is equivalent to 300 volts secondary divided by VSWELL; therefore, when VSELECT := VY the maximum Vbase in primary kV is the following:

$$\dfrac{300V \cdot PTRY \cdot 100}{VSWELL \cdot 1000} = \dfrac{30V \cdot PTRY}{VSWELL}$$

Equation 4.8

When VSELECT := VZ, the maximum Vbase in primary kV is the following:

$$\dfrac{300V \cdot PTRZ \cdot 100}{VSWELL \cdot 1000} = \dfrac{30V \cdot PTRZ}{VSWELL}$$

Equation 4.9

If the expected higher end of the "normal" system voltage range is close to 300 V secondary, then the VSWELL setting may need to be reduced or turned "OFF" to allow Vbase to track the actual system voltage and not run into the maximum value limit. For example, if connecting to an industrial service rated

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at 277 V_{LN} / 480 V_{LL} using the wye-connection (with no PTs), and the normal operating range goes as high as 285 V_{LN}, then the maximum VSWELL setting that will allow for proper Vbase tracking is 105 percent.

SSI Reset Command

After commissioning tests or other maintenance activities that have applied test voltages to the SEL-651R-2, the Vbase element may have locked onto a test voltage. Use the **SSI R** (reset) command once normal system voltages are restored on the voltage terminals. Powering up the relay automatically performs this reset.

See *Commissioning Testing on page 12.46* for more details.

Power Elements

Four independent three-phase power elements are available. Group setting EPWR determines how many (and what type of) power elements are enabled:

EPWR := **N, 3P1, 3P2, 3P3, 3P4**

where

N	None
3P1	Enable one (1) three-phase power element
3P2	Enable two (1, 2) three-phase power elements
3P3	Enable three (1, 2, 3) three-phase power elements
3P4	Enable four (1, 2, 3, 4) three-phase power elements

Each enabled power element can be set to detect real power or reactive power, with the settings in *Table 4.21*. With SELOGIC control equations, the power elements provide a wide variety of protection and control applications. Typical applications are:

➤ Overpower and/or underpower protection/control

➤ Reverse power protection/control

➤ VAR control for capacitor banks

Power Elements Settings

Table 4.21 Three-Phase Power Element Settings and Setting Ranges (EPWR := 3P1, 3P2, 3P3, or 3P4)

Settings	Definition	Range
3PWR1P, 3PWR2P, 3PWR3P, 3PWR4P	Power element pickup	OFF, 1.20–7800.00 VA secondary, three-phase
PWR1T, PWR2T, PWR3T, PWR4T	Power element type	+WATTS, –WATTS, +VARS, –VARS
PWR1D, PWR2D, PWR3D, PWR4D	Power element time delay	0.00–16000 cycles, in 0.25-cycle steps

NOTE: The CT Polarity Setting (CTPOL) on page 9.29 affects the sign of the calculated power quantities.

The power element type settings are made in reference to the load convention:

+WATTS: positive or forward real power
–WATTS: negative or reverse real power
+VARS: positive or forward reactive power (lagging)
–VARS: negative or reverse reactive power (leading)

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Power Element Time Delay Setting Considerations

The four power element time delay settings (PWR1D–PWR4D) can be set to have no intentional delay for testing purposes. For protection applications involving the power element Relay Word bits, SEL recommends a minimum time delay setting of 5.00 cycles for general applications. The classical power calculation is a product of voltage and current, to determine the real and reactive power quantities. During a system disturbance, because of the high sensitivity of the power elements, the changing system phase angles and/or frequency shifts may cause transient errors in the power calculation.

Using Power Elements in the Relay Trip Equation

The power elements are not supervised by any relay elements other than the minimum voltage and current level checks shown in *Figure 4.44*. If the protection application requires overcurrent protection in addition to the power elements, there may be a race condition, during a fault, between the overcurrent element(s) and the power element(s) if the power element(s) are still receiving sufficient operating quantities. In some protection schemes this may jeopardize coordination. One method of accommodating this is to increase the power element time delay settings.

Another method is to supervise the power element Relay Word bit(s) with the overcurrent element pickup (the overcurrent element has effective priority over the power element). For example, if the application requires that the relay trip the attached circuit breaker when a forward power flow threshold is exceeded and a phase definite-time overcurrent element is also in the relay trip equation, extra security can be achieved with these SELOGIC control equation settings:

SV01 := **3PWR1 AND NOT 50P1**

SV01PU := **1.50 cycle**

SV01DO := **0.00 cycles**

And Group settings:

50P1P := **5.00 A**

50P1D := **10.00 cycles**

3PWR1P := **360.00 VA**

PWR1T := **+WATTS**

PWR1D := **5.00 cycles**

TR3P := **... OR ... OR SV01T OR 50P1T**

During a fault that exceeds the pickup values of both the power element and the overcurrent element, these settings ensure that the definite-time overcurrent element (50P1T) trips the relay for the fault, even if the PWR1D setting is set to a smaller time delay than the 50P1D setting. Relay Word bit 3PWR1 is ANDed with Relay Word bit NOT(50P1), which effectively blocks 3PWR1 when 50P1 is asserted. The SELOGIC variable timer SV01 is employed in this example to avoid another race condition that could occur if the fault was cleared by another device before the definite-time element time-out, which could potentially deassert 50P1 a few quarter-cycles before 3PWR1 deasserts. Without this timer, an incorrect trip operation may occur.

Accuracy

See *Specifications on page 1.9*.

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Three-Phase Power Element Calculations

The numeric method used in the three-phase power elements uses line-to-line voltage and phase current quantities, corrected with zero-sequence voltage and current when unbalanced. The resulting power quantities are subject to the minimum voltage and current tests shown in the lower half of *Figure 4.44*.

Power Elements Logic Operation
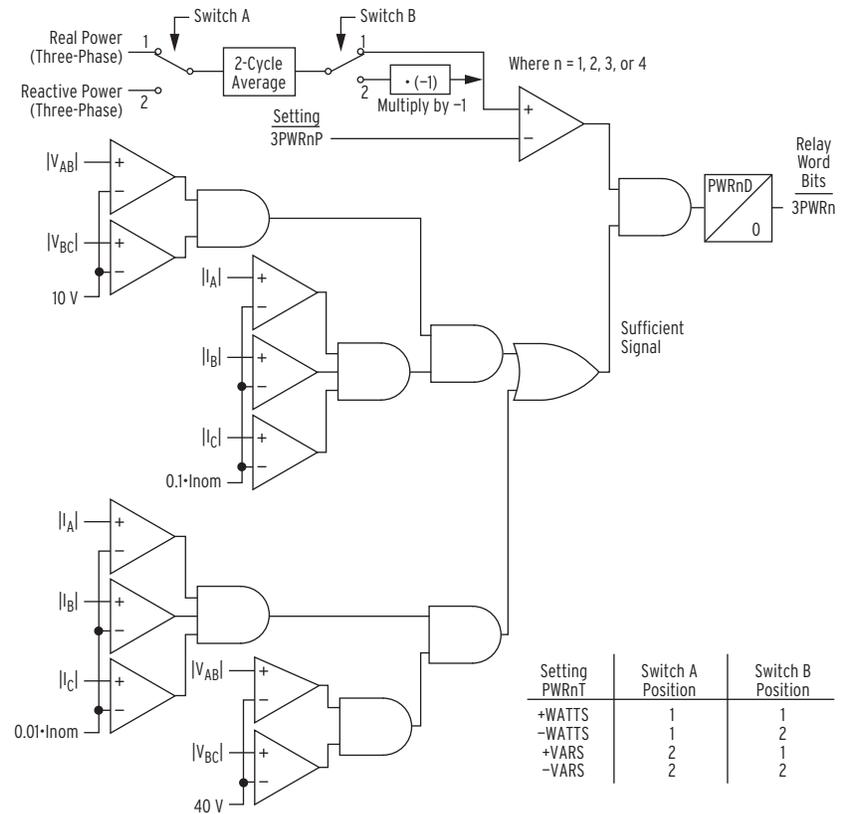
Figure 4.44   Three-Phase Power Elements Logic

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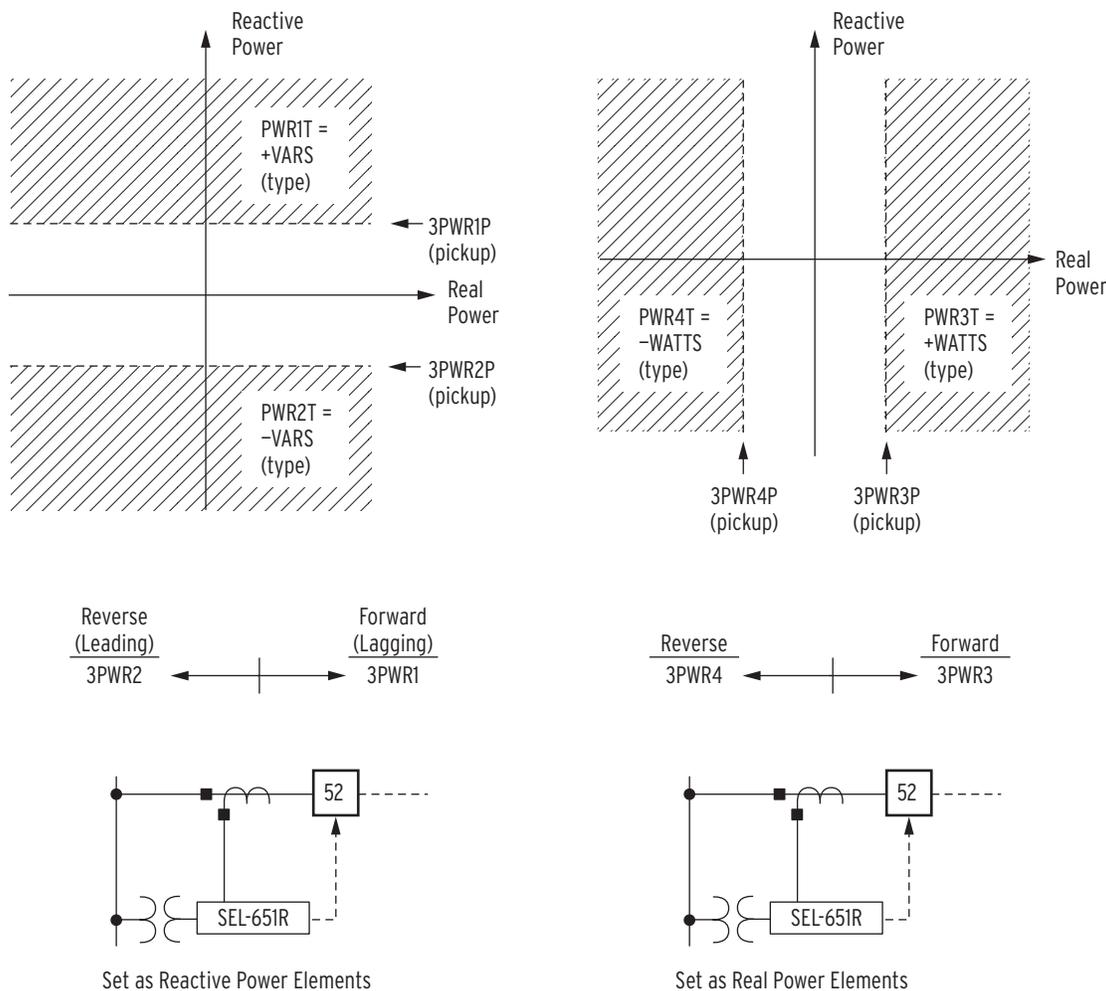
Figure 4.45   Power Elements Operation in the Real/Reactive Power Plane

In *Figure 4.45*, if the three-phase reactive power level is above pickup setting 3PWR*n*P, Relay Word bit 3PWR*n* asserts (3PWR*n* = logical 1) after time delay setting PWR*n*D (*n* = 1–4), subject to the "sufficient signal" conditions.

The "sufficient signal" conditions in *Figure 4.45* require at least 1 percent nominal current if the corresponding phase voltage is greater than 40 V secondary. If the voltage is between 10 and 40 V secondary, at least 10 percent nominal current is required.

Pickup setting 3PWR*n*P is always a positive number value (see *Table 4.21*). Thus, if –WATTS or –VARS are chosen with setting PWR*n*T, the corresponding real or reactive power values have to effectively be multiplied by –1 so that element PWR*n* asserts for negative real or reactive power.

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Power Elements Application—VAR Control for a Capacitor Bank
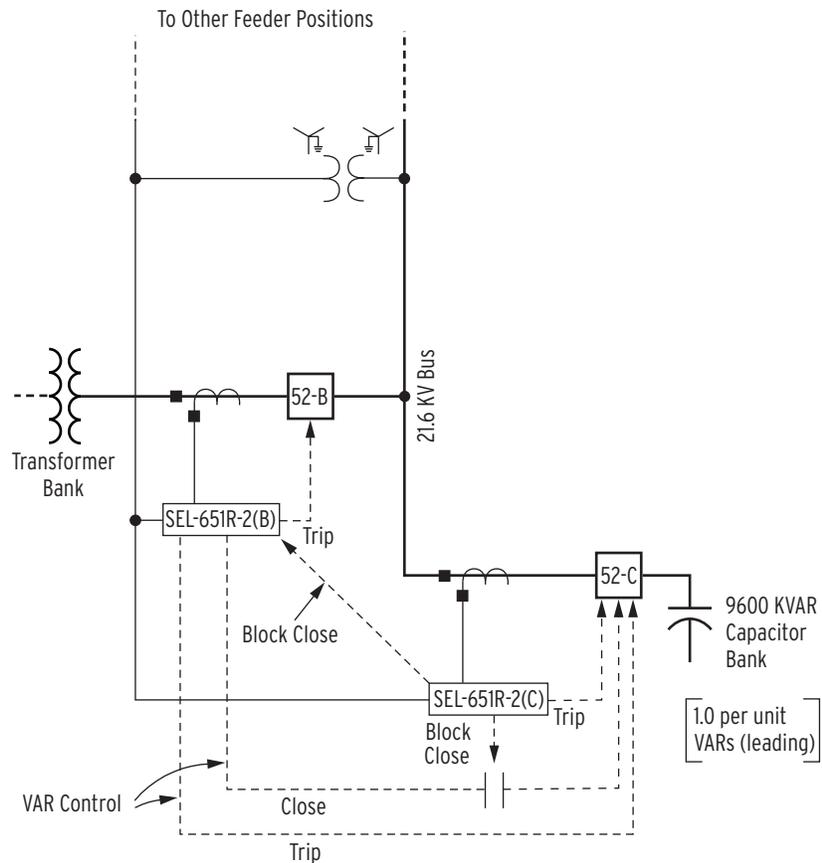
Figure 4.46   SEL-651R-2(B) Provides VAR Control for 9600 kVAR Capacitor Bank

The 9600 kVAR capacitor bank in *Figure 4.46* is put online and taken offline according to the VAR loading on the transformer bank feeding the 21.6 kV bus. The VAR loading is measured with the SEL-651R-2(B) located at bus circuit breaker 52-B.

Two SEL-651R-2 recloser controls operate the capacitor bank—both recloser controls are connected to capacitor bank circuit breaker 52-C. The SEL-651R-2(C) provides capacitor overcurrent protection and trips circuit breaker 52-C for a fault in the capacitor bank. The SEL-651R-2(B) provides VAR control and automatically puts the capacitor bank online (closes circuit breaker 52-C) or takes it offline (trips circuit breaker 52-C) according to the measured VAR level. The SEL-651R-2(B) also provides bus overcurrent protection and trips circuit breaker 52-B for a fault on the 21.6 kV bus.

In *Figure 4.46*, if the SEL-651R-2(C) trips circuit breaker 52-C for a fault in the capacitor bank, then a block close signal is sent from the SEL-651R-2(C) to the SEL-651R-2(B). This prevents the SEL-651R-2(B) from issuing an automatic close to circuit breaker 52-C.

For additional security, the close circuit from the SEL-651R-2(B) to circuit breaker 52-C is supervised by a block close output contact from the SEL-651R-2(C). This block close output contact opens if the SEL-651R-2(C) trips circuit breaker 52-C for a fault in the capacitor bank—no automatic closing can then take place.

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These block close signals seal in when the SEL-651R-2(C) trips circuit breaker 52-C for a fault in the capacitor bank. Automatic closing of circuit breaker 52-C with the SEL-651R-2(B) can then take place only after the block close signals are reset. The exact implementation of this block close logic requires an application note beyond the scope of this discussion.

The rest of this discussion focuses on the determination of VAR levels (and corresponding power element settings) for automatic tripping and closing of circuit breaker 52-C with the SEL-651R-2(B).

Convert three-phase 9600 kVAR (kVA) to three-phase VA (volt-amperes) secondary, assuming a 1000:1 current transformer ratio and 100:1 potential transformer ratio:

$$9600 \text{ kVA pri} \cdot \frac{1000 \text{ V}}{1 \text{ kV}} \cdot \frac{1}{1000} \cdot \frac{1}{100} = 96 \text{ VA secondary}$$

The three-phase 9600 kVAR capacitor is converted to 1.0 per unit VARs (leading) for demonstration convenience in *Figure 4.46*. *Figure 4.47* shows the per unit VAR levels for putting online (closing circuit breaker 52-C) or taking offline (tripping circuit breaker 52-C) the capacitor bank.
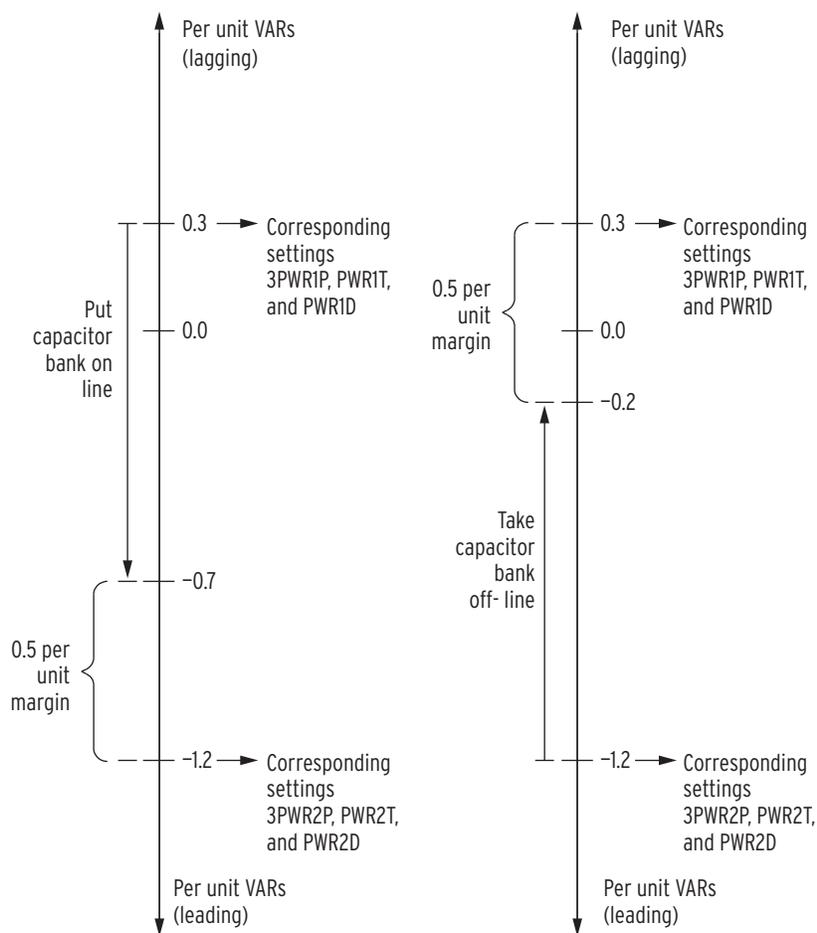
Figure 4.47   Per Unit Setting Limits for Switching 9600 kVAR Capacitor Bank Online and Offline

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The capacitor bank is put online at the 0.3 per unit VAR level (lagging) on the bus. The per unit VAR level immediately changes to the –0.7 per unit VAR level (leading) when the capacitor bank is put online (0.3 – 1.0 = –0.7). There is a margin of 0.5 per unit VARs until the capacitor bank is then taken offline (–0.7 – 0.5 = –1.2).

The capacitor bank is taken offline at the –1.2 per unit VAR level (leading) on the bus. The per unit VAR level immediately changes to –0.2 per unit VAR level (leading) when the capacitor bank is taken offline (–1.2 + 1.0 = –0.2). There is a margin of 0.5 per unit VARs until the capacitor bank is put online again (–0.2 + 0.5 = 0.3).

Settings for Three-Phase Power Elements

From preceding calculations and figures:

9600 kVAR ≈ 1.0 per unit VARs ≈ 96.0 VA secondary (three-phase)

Convert the per unit VAR levels 0.3 and –1.2 to VA (volt-amperes) secondary:

0.3 • 96.0 VA secondary = 28.8 VA secondary

–1.2 • 96.0 VA secondary = –115.2 VA secondary

Make the following power element settings for the SEL-651R-2(B):

EPWR := **2** (enable two power elements)

3PWR1P := **28.8** (power element pickup; VA secondary)

PWR1T := **+VARS** (power element type; lagging VARs)

PWR1D := **____** (power element time delay; cycles; see following discussion for setting idea)

3PWR2P := **115.2** (power element pickup; VA secondary)

PWR2T := **–VARS** (power element type; leading VARs)

PWR2D := **____** (power element time delay; cycles; see following discussion for setting idea)

To override transient reactive power conditions, set the above power element time delay settings equivalent to several seconds (or perhaps minutes).

Resulting three-phase power element 3PWR1 asserts when the lagging VAR level exceeds the 0.3 per unit VAR level (lagging) (See *Figure 4.47* and left-hand side of *Figure 4.45*.) This element is used in close logic in the SEL-651R-2(B) to automatically put the 9600 kVAR capacitor bank online.

Resulting three-phase power element 3PWR2 asserts when the leading VAR level exceeds the –1.2 per unit VAR level (leading) (see *Figure 4.47* and the left-hand side of *Figure 4.45*). This element is used in trip logic in the SEL-651R-2(B) to automatically take the 9600 kVAR capacitor bank offline.

Load-Encroachment Logic

The load-encroachment logic (see *Figure 4.48*) and settings are enabled/disabled with setting ELOAD (:= Y or N). (If Global setting VSELECT := OFF, then ELOAD can be set only to N. See *Voltage Source Selection Setting (VSELECT) on page 9.33* for more details on the VSELECT setting.)

The load-encroachment feature allows phase overcurrent elements to be set without regard for load levels. This is especially helpful in bus overcurrent applications. A bus relay sees the cumulative currents of all the feeders but still has to provide overcurrent backup protection for all these feeders. If the phase elements in the bus relay are set to provide adequate backup, they often are set close to maximum bus load current levels. This runs the risk of tripping on bus load current. The load-encroachment feature prevents this from happening as shown in the example that follows in this subsection.
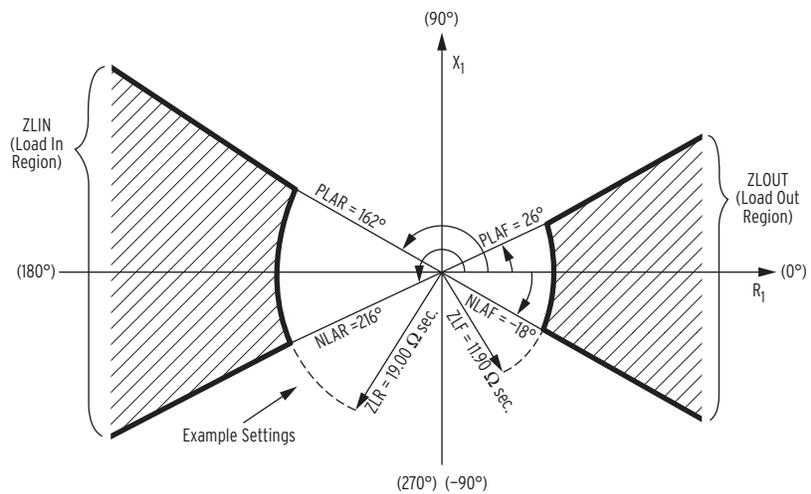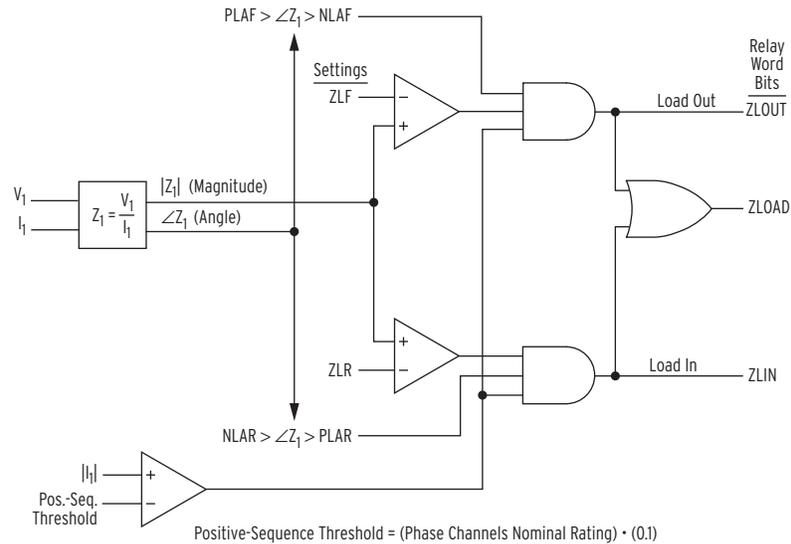
Figure 4.48   Load-Encroachment Logic

Note that a positive-sequence impedance calculation (Z_1) is made in the load-encroachment logic in *Figure 4.48*. Load is largely a balanced condition, so apparent positive-sequence impedance is a good load measure. The load-encroachment logic operates only if the positive-sequence current (I_1) is greater than the Positive-Sequence Threshold defined in *Figure 4.48*. For a balanced load condition, I_1 = phase current magnitude.

Forward load (load flowing out) lies within the hatched region labeled ZLOUT. Relay Word bit ZLOUT asserts to logical 1 when the load lies within this hatched region.

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NOTE: The CT Polarity Setting (CTPOL) on page 9.29 affects the sign of the positive-sequence impedance calculation.

Reverse load (load flowing in) lies within the hatched region labeled ZLIN. Relay Word bit ZLIN asserts to logical 1 when the load lies within this hatched region.

Relay Word bit ZLOAD is the OR-combination of ZLOUT and ZLIN:

ZLOAD := **ZLOUT OR ZLIN**

Settings Ranges

Refer to *Table 4.22*.

Table 4.22   Load-Encroachment Settings Ranges

Setting[a]	Description and Range
ZLF	Forward Minimum Load Impedance-corresponding to maximum load flowing out 0.50-640.00 ohms secondary
ZLR	Reverse Minimum Load Impedance-corresponding to maximum load flowing in 0.50-640.00 ohms secondary
PLAF	Maximum Positive Load Angle Forward ($-90°$ to $+90°$)
NLAF	Maximum Negative Load Angle Forward ($-90°$ to $+90°$)
PLAR	Maximum Positive Load Angle Reverse ($+90°$ to $+270°$)
NLAR	Maximum Negative Load Angle Reverse ($+90°$ to $+270°$)

[a] If Global setting VSELECT := VY and LEA ac inputs are ordered, the impedance values for ZLF and ZLR must be scaled (see Line Impedance Conversions (Group Settings) on page 9.50).

Load-Encroachment Setting Example

Example system conditions:

Nominal Line-Line Voltage:	230 kV
Maximum Forward Load:	800 MVA
Maximum Reverse Load:	500 MVA
Power Factor (Forward Load):	0.90 lag to 0.95 lead
Power Factor (Reverse Load):	0.80 lag to 0.95 lead
CT ratio:	400/1 = 400
PT ratio:	134000/67 = 2000

The PTs are connected line-to-neutral.

Convert Maximum Loads to Equivalent Secondary Impedances

Start with maximum forward load:

$$800 \text{ MVA} \cdot (1/3) = 267 \text{ MVA per phase}$$

$$230 \text{ kV} / (\sqrt{3}) = 132.8 \text{ kV line-to-neutral}$$

$$267 \text{ MVA} \cdot (1/132.8 \text{ kV}) \cdot (1000\text{kV/MV}) = 2010 \text{ A primary}$$

$$2010 \text{ A primary} \cdot (1/\text{CT ratio}) = 2010 \text{ A primary} \cdot (1 \text{ A secondary}/400 \text{ A primary})$$
$$= 5.03 \text{ A secondary}$$

$$132.8 \text{ kV} \cdot (1000 \text{ V/kV}) = 132800 \text{ V primary}$$

$$132800 \text{ V primary} \cdot (1/\text{PT ratio}) = 132800 \text{ V primary} \cdot (1 \text{ V secondary}/2000 \text{ V primary})$$
$$= 66.4 \text{ V secondary}$$

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Now, calculate the equivalent secondary impedance:

66.4 V secondary/5.03 A secondary = 13.2 Ω secondary

This Ω secondary value can be calculated more expediently with the following equation:

[(line-line voltage in kV)^2 • (CT ratio)]/[(three-phase load in MVA) • (PT ratio)]

Again, for the maximum forward load:

[(230)^2 • (400)]/[(800) • (2000)] = 13.2 Ω secondary

To provide a margin for setting ZLF, multiply by a factor of 0.9:

ZLF := **13.2 Ω secondary • 0.9 = 11.90 Ω secondary**

For the maximum reverse load:

[(230)^2 • (400)]/[(500) • (2000)] = 21.1 Ω secondary

Again, to provide a margin for setting ZLR:

ZLR := **21.1 Ω secondary • 0.9 = 19.00 Ω secondary**

Convert Power Factors to Equivalent Load Angles

The power factor (forward load) can vary from 0.90 lag to 0.95 lead.

PLAF := **cos^{-1} (0.90) = 26°**

NLAF := **cos^{-1} (0.95) = −18°**

The power factor (reverse load) can vary from 0.80 lag to 0.95 lead.

PLAR := **180° − cos^{-1} (0.95) = 180° − 18° = 162°**

NLAR := **180° + cos^{-1} (0.80) = 180° + 37° = 217°**

Apply Load-Encroachment Logic to a Phase Time-Overcurrent Element

Again, from *Figure 4.48*:

ZLOAD := **ZLOUT OR ZLIN**

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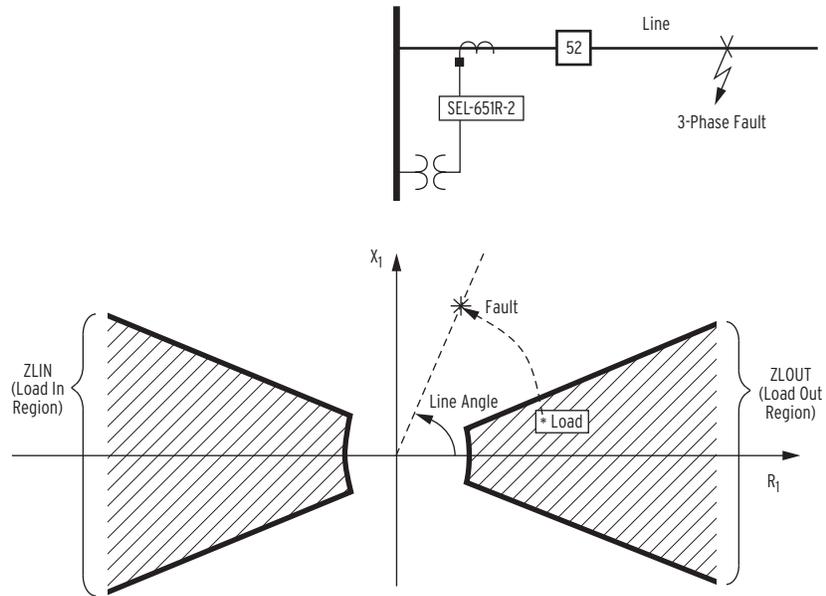
Figure 4.49   Migration of Apparent Positive-Sequence Impedance for a Fault Condition

Refer to *Figure 4.49*. In a load condition, the apparent positive-sequence impedance is within the ZLOUT area, resulting in:

ZLOAD := **ZLOUT OR ZLIN = logical 1 OR ZLIN = logical 1**

If a fault occurs, the apparent positive-sequence impedance moves outside the ZLOUT area (and stays outside the ZLIN area, too), resulting in:

ZLOAD := **ZLOUT OR ZLIN = logical 0 OR logical 0 = logical 0**

Load Encroachment for Directionally Controlled Elements

Directional elements can be used in torque-control settings for directional control of phase time overcurrent elements, as shown in *Table 4.25*. Directional control elements come from *Figure 4.61*, which refers back to *Figure 4.60*. In *Figure 4.60*, notice that the "NOT ZLOAD" condition is embedded in the positive-sequence voltage-polarized directional element logic. This logic prevents a phase overcurrent element that is being torque controlled by a directional element from operating when the measured positive sequence impedance is within the Load In or Load Out regions.

Load Encroachment for Nondirectional Elements

It is possible to use SELOGIC control equation torque-control settings to apply load encroachment supervision for nondirectional overcurrent elements. However, keep in mind that load encroachment is not a valid representation of the positive-sequence impedance during unbalanced faults, and ZLOAD may assert during certain unbalanced faults. This means that a torque-control equation intended to prevent operation of a phase overcurrent element for load conditions may also prevent operation of the element for unbalanced faults. Therefore, when using load encroachment to control phase overcurrent elements, residual or neutral-ground overcurrent elements must be used to detect phase-ground faults. Similarly negative-sequence overcurrent elements must be used to detect phase-to-phase faults (see *Setting Negative-Sequence Overcurrent Elements on page 4.105*). These phase-to-ground and phase-to-phase elements must be at least as sensitive as the phase overcurrent elements.

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Example 1

If it is acceptable for the phase overcurrent element to operate for some unbalanced fault conditions, refer to *Figure 4.16* and make the following SELOGIC control equation torque-control setting:

> 51PTC := **NOT(ZLOAD) AND NOT(LOP) OR 50P6**

As shown in *Figure 4.48*, load-encroachment logic is a positive-sequence calculation. During LOP conditions (loss-of-potential; see *Figure 4.50*), positive-sequence voltage (V_1) can be substantially depressed in magnitude or changed in angle. This change in V_1 can possibly cause ZLOAD to deassert (= logical 0), erroneously indicating that a "fault condition" exists. Thus, NOT (ZLOAD) should be supervised by NOT (LOP) in a torque-control setting. This also effectively happens in the directional element in *Figure 4.60*, where ZLOAD and LOP are part of the logic.

In the above setting example, phase instantaneous overcurrent element 50P6 is set above any maximum load current level—if 50P6 picks up, there is assuredly a fault. For faults below the pickup level of 50P6, but above the pickup of phase time-overcurrent element 51PT, the NOT(ZLOAD) AND NOT(LOP) logic discriminates between high load and fault current. If an LOP condition occurs (LOP = logical 1), the pickup level of 50P6 becomes the effective pickup of phase time-overcurrent element 51PT (51PT loses its sensitivity when an LOP condition occurs):

> 51PTC := **NOT(ZLOAD) AND NOT(LOP) OR 50P6**
>
> := **NOT(ZLOAD) AND NOT(logical 1) OR 50P6**
>
> := **50P6**

Example 2

If it is *not* acceptable for the phase overcurrent element to operate for any unbalanced fault current less than 50P6P or for load conditions, enable load encroachment, refer to *Figure 4.16*, and make the following SELOGIC control equation torque-control setting:

> 51PTC = **F32P OR R32P OR 50P6**

This uses the directional control logic (*Figure 4.60*) to cause the phase overcurrent element to be sensitive only to three-phase fault conditions. Residual or neutral ground-overcurrent elements must be used to detect phase-to-ground faults, and negative-sequence overcurrent elements must be used to detect phase-to-phase faults (see *Setting Negative-Sequence Overcurrent Elements on page 4.105*). These phase-to-ground and phase-to-phase elements must be at least as sensitive as the phase overcurrent elements.

Because the directional control logic is defeated when a loss-of-potential occurs, phase instantaneous overcurrent element 50P6 is set above any maximum load current level—if 50P6 picks up, there is assuredly a fault. If an LOP condition occurs (LOP = logical 1), the pickup level of 50P6 becomes the effective pickup of phase time-overcurrent element 51PT. In other words, 51PT loses its sensitivity when an LOP condition occurs.

The directional elements must be enabled by setting E32 to Y or AUTO. See *Directional Control Settings on page 4.89* for a discussion of other settings that may be necessary for directional control to function properly.

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See SEL Application Guide *AG2005-07, Guidelines for Applying Load-Encroachment Element for Overcurrent Supervision*, available on the SEL website, for more information.

Use SEL-321 Relay Application Guide for the SEL-651R-2

The load-encroachment logic and settings in the SEL-651R-2 are similar to those in the SEL-321. Refer to SEL Application Guide *AG93-10, SEL-321 Relay Load-Encroachment Function Setting Guidelines* for applying the load-encroachment logic in the SEL-651R-2. Note that *Application Guide AG93-10* discusses applying the load-encroachment feature to phase distance elements in the SEL-321. The SEL-651R-2 does not have phase distance elements, but the principles and settings example are still generally applicable to the SEL-651R-2.

Ground Switch Logic

PHASE CURRENT CHANNEL ASSIGNMENTS
Made with Global setting IPCONN (see Table 9.8).

Global setting EGNDSW is the primary control for the ground switch logic. The operation of the ground switch logic is summarized in *Table 4.23* and its outputs are listed below:

➤ Ground current I_G

➤ Relay Word bit GNDSW (indicating the I_G current source)

RESIDUALLY CONNECTED CHANNEL IN
The following figures show the factory-default wiring for channel IN wired residually with the phase current channels for the various recloser applications: Figure 2.49, Figure 2.52, Figure 2.55, Figure 2.59, Figure 2.62, Figure 2.65, Figure 2.68, Figure 2.70, Figure 2.71, Figure 2.76, and Figure 2.77.

Ground current I_G is used in the following:

➤ Ground instantaneous/definite-time overcurrent elements (see *Ground Instantaneous/ Definite-Time Overcurrent Elements on page 4.9*)

➤ Ground time-overcurrent elements (see *Ground Time-Overcurrent Elements on page 4.23*)

➤ Directional control (see *Ground Current I_G on page 4.80*)

➤ Metering (see *Ground Switch Option on page 8.3*)

Table 4.23 Ground Switch Logic

Scenario	Channel IN Wiring Configuration	Global Setting EGNDSW :=	Current Transformer Ratio Settings	Source of Ground Current I_G	
				When $|IN| < 4.7$ A, Relay Word bit GNDSW = logical 1	When $|IN| \geq 4.7$ A, Relay Word bit GNDSW = logical 0
1 (factory default)	Residually connected with phase current channels	Y	CTR = CTRN	IN	$3I_0$
2	Separate core-balance CT, encompassing all three phases, on same line section as phase CTs	Y	CTR ≥ CTRN	IN	$3I_0 \bullet \left(\dfrac{CTR}{CTRN} \right)$
				At all times Relay Word bit GNDSW = logical 0	
3	Separate current source (unrelated to phase currents)	N	CTR and CTRN set independently	$3I_0$	
4	Not connected	N	Make CTR; CTRN "don't care"	$3I_0$	

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EXTRA ELEMENTS ENABLED WHEN EGNDSW := N
See Neutral Instantaneous/ Definite-Time Overcurrent Elements on page 4.7 and Neutral Time-Overcurrent Elements on page 4.21.

When Global setting EGNDSW := Y (Scenarios 1 and 2 in *Table 4.23*), ground current I_G is automatically switched between the following (depending on the magnitude of channel IN current):

➤ channel IN current

➤ calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (vector summation)

The switching point of 4.7 A secondary (channel IN current) in *Table 4.23* has some intentional hysteresis to prevent rapid I_G current source changes. EGNDSW:= Y gives the aforementioned ground overcurrent elements the widest range for pickup settings and operating current. It especially provides for increased sensitivity at lower ground current values.

Notice that for uncommon Scenario 2 in *Table 4.23*, the $3I_0$ current is adjusted by the current transformer ratio settings CTR and CTRN. This is because the secondary current $3I_0$ needs to be adjusted to the channel IN current base because the ground overcurrent elements (that operate off of ground current I_G) are set on the channel IN current base when EGNDSW:= Y.

If current transformer ratio settings are set the same (CTR = CTRN), then the phase channel current base is the same as the channel IN current base.

When Global setting EGNDSW := N (Scenarios 3 and 4 in *Table 4.23*), ground current I_G is fixed on the calculated residual-ground current $3I_0 = I_A + I_B + I_C$ (vector summation).

Loss-of-Potential Logic

The loss-of-potential (LOP) logic operates as shown in *Figure 4.50*.
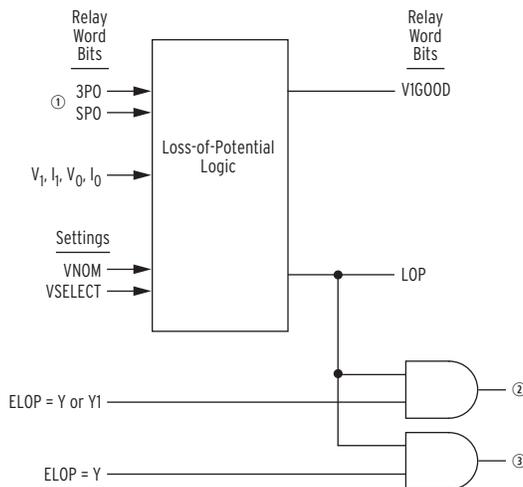
① From Figure 5.5; ② to Figure 4.52 and Figure 4.53; ③ to Figure 4.57 and Figure 4.61.

Figure 4.50   Loss-of-Potential Logic

Inputs into the LOP logic are described in *Table 4.24*.

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Table 4.24 LOP Logic Inputs

Input	Description
3PO	Three-pole open condition (indicates circuit breaker open condition).
SPO	Single-pole open condition (indicates one or two phases are open, of a single-pole trip capable recloser)
V_1	Positive-sequence voltage (V secondary).
I_1	Positive-sequence current (A secondary).
I_0	Zero-sequence current (A secondary).
V_0	Zero-sequence voltage (V secondary).
VNOM	PT nominal voltage setting (line-to-neutral secondary).
VSELECT	Voltage source selection (global) setting—selects three-phase source (VY or VZ) for LOP, directional logic, etc.
ELOP	Loss-of-potential enable setting.

The circuit breaker has to be closed (Relay Word bit 3PO = logical 0 and SPO = logical 0) for the LOP logic to operate.

A loss of potential is declared (Relay Word bit LOP = logical 1) when a 10 percent or larger drop in V_1 is detected, with no corresponding change in I_1 or I_0. If the LOP condition persists for 15 cycles, it latches in.

LOP resets (Relay Word bit LOP = logical 0) when V_1 returns above 85 percent of setting VNOM (Relay Word bit V1GOOD also asserts) and V_0 is less than 7.8 percent of setting VNOM.

The loss-of-potential enable setting, ELOP, does not enable or disable the LOP logic. It just routes the LOP Relay Word bit to different logic, as shown in *Figure 4.50* and explained in the remainder of this subsection.

Setting VSELECT := OFF

If setting VSELECT := OFF, the loss-of-potential logic is disabled (Relay Word bits LOP and V1GOOD are forced to logical 0) and setting ELOP can only be set to "N."

Setting ELOP := Y or Y1

If setting ELOP := Y or Y1 and a loss-of-potential condition occurs (Relay Word bit LOP asserts to logical 1), all directional element enables are disabled (see *Figure 4.52*, *Figure 4.53*, and *Figure 4.60*). The loss-of-potential condition makes the voltage-polarized directional elements (which are controlled by these internal enables) unreliable. Thus, they are disabled. The overcurrent elements controlled by these voltage-polarized directional elements are disabled also (unless overridden by conditions explained in the following Setting ELOP := Y discussion).

Setting ELOP := Y

Additionally, if setting ELOP := Y and a loss-of-potential condition occurs (Relay Word bit LOP asserts to logical 1), overcurrent elements set direction forward are enabled (see *Figure 4.57* and *Figure 4.61*). These direction forward overcurrent elements effectively become nondirectional and provide overcurrent protection during a loss-of-potential condition.

As detailed previously, voltage-based directional elements are disabled during a loss-of-potential condition. Thus, the overcurrent elements controlled by these voltage-based directional elements are also disabled. However, this disable condition is overridden for the overcurrent elements set direction forward if setting ELOP := Y.

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Setting ELOP := N

If setting ELOP := N, the loss-of-potential logic still operates (Relay Word bit LOP asserts to logical 1 for a loss-of-potential condition) but does not disable any voltage-based directional elements (as occurs with ELOP := Y or Y1) or enable overcurrent elements set direction forward (as occurs with ELOP := Y).

Directional Control for Ground Overcurrent Logic

Setting E32 enables directional control for overcurrent elements. Setting E32 and other directional control settings are described in *Directional Control Settings on page 4.89*.

Two elements are available to control the ground overcurrent elements. These two directional elements are:

➤ Negative-sequence voltage-polarized directional element

➤ Zero-sequence voltage-polarized directional element
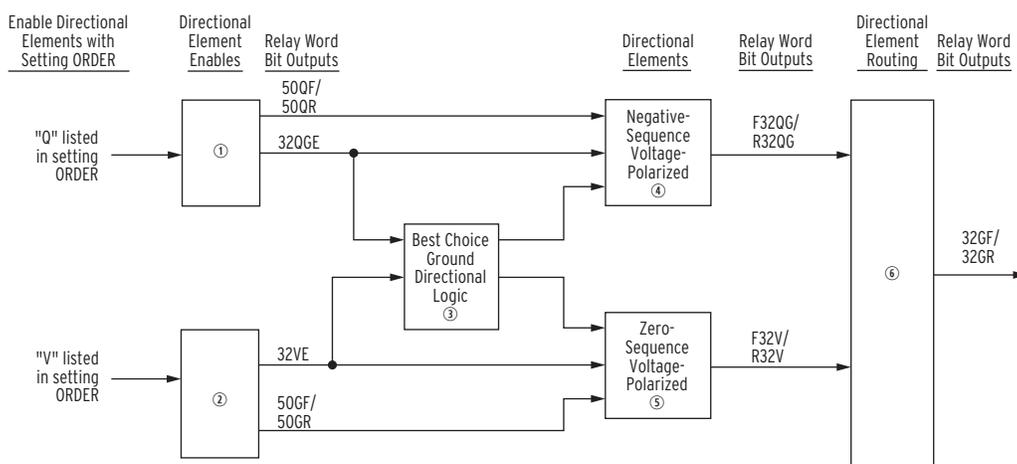
① Figure 4.52; ② Figure 4.53; ③ Figure 4.54; ④ Figure 4.55; ⑤ Figure 4.56; ⑥ Figure 4.57.

Figure 4.51 General Logic Flow of Directional Control for Ground Overcurrent Elements

Figure 4.51 gives an overview of how these directional elements are enabled and routed for control of the ground overcurrent elements.

Note in *Figure 4.51* that setting ORDER enables the directional elements. Set ORDER with any combination of Q and V. They have the following correspondence to the directional elements:

➤ Q (Negative-sequence voltage-polarized directional element)

➤ V (Zero-sequence voltage-polarized directional element)

The order in which these directional elements are listed in setting ORDER determines the priority in which they operate to provide Best Choice Ground Directional Element logic control. See discussion on setting ORDER in *Directional Control Settings on page 4.89*.

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Directional Element Enables

Refer to *Figure 4.51*, *Figure 4.52*, and *Figure 4.53*.

The directional element enables, Relay Word bits 32QGE and 32VE, have the following correspondence to the directional elements:

➤ 32QGE (Negative-sequence voltage-polarized directional element)

➤ 32VE (Zero-sequence voltage-polarized directional element)

Note in *Figure 4.52* and *Figure 4.53* that if:

➤ enable setting ELOP = Y or Y1 and a loss-of-potential condition occurs (Relay Word bit LOP asserts; see *Table 4.50*)

➤ or a single-pole open condition occurs (Relay Word bit SPO asserts; see *Table 5.5*)

then both directional element enables are disabled. The directional element enables also have current signal thresholds that must be met (settings 50QFP/50QRP and 50GFP/50GRP, respectively).

Figure 4.52 has extra directional element enable 32QE, which is used in the logic that controls the negative-sequence and phase overcurrent elements (see *Figure 4.58* and *Figure 4.59*).

The settings involved with 32QGE and 32VE in *Figure 4.52* and *Figure 4.53* (e.g., settings a2, k2, a0G, E32IV) are explained in *Directional Control Settings on page 4.89*.

Ground Current I_G

Ground current I_G in *Figure 4.52*, *Figure 4.53*, and *Figure 4.56* can possibly switch between sources, depending on Global setting EGNDSW (see *Table 4.23* and accompanying text).

Best Choice Ground Directional Element Logic

Refer to *Figure 4.51* and *Figure 4.54*.

Relay Word bits 32QGE and 32VE and setting ORDER are used in the Best Choice Ground Directional Element logic in *Figure 4.54*. The Best Choice Ground Directional Element logic determines the order in which the directional element should be enabled to operate. The ground overcurrent elements set for directional control are then controlled by this directional element.

Directional Elements

Refer to *Figure 4.51*, *Figure 4.55*, and *Figure 4.56*.

The enable output of Best Choice Ground Directional Element logic in *Figure 4.54* determines which directional element will run.

Presuming sufficient current signal is present (Relay Word bit 50GF, 50GR, 50QF, or 50QR asserted), an impedance-based directional calculation is then made. Technical paper *Negative-Sequence Impedance Directional Element* by Bill Fleming goes into more detail on this impedance-based calculation for the negative-sequence voltage-polarized directional element (paper available at selinc.com/literature/technical-papers/). The principles discussed in this paper also generally apply to the zero-sequence voltage-polarized directional element.

Directional Element Routing

Refer to *Figure 4.51* and *Figure 4.57*.

The directional element outputs are routed to the forward (Relay Word bit 32GF) and reverse (Relay Word bit 32GR) logic points, for use in controlling ground overcurrent elements.

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Table 4.25 and accompanying text give examples of directional control implementation (i.e., by using the outputs of *Figure 4.57* and *Figure 4.61* in overcurrent element torque-control settings and other SELOGIC settings to realize desired directional control).

Loss-of-Potential

Note in *Figure 4.57* that if *both* the following are true:

➤ enable setting ELOP = Y

➤ a loss-of-potential condition occurs (Relay Word bit LOP asserts; see *Figure 4.50*)

then the forward logic point (Relay Word bit 32GF) asserts to logical 1, thus enabling the ground overcurrent elements that are set direction forward. These direction forward overcurrent elements effectively become nondirectional and provide overcurrent protection during a loss-of-potential condition.

As detailed in *Figure 4.52* and *Figure 4.53*, voltage-based directional elements are disabled during a loss-of-potential condition. Thus, the overcurrent elements that are directionally controlled by these voltage-based directional elements are disabled also. But this disable condition is overridden if setting ELOP := Y, as explained above.
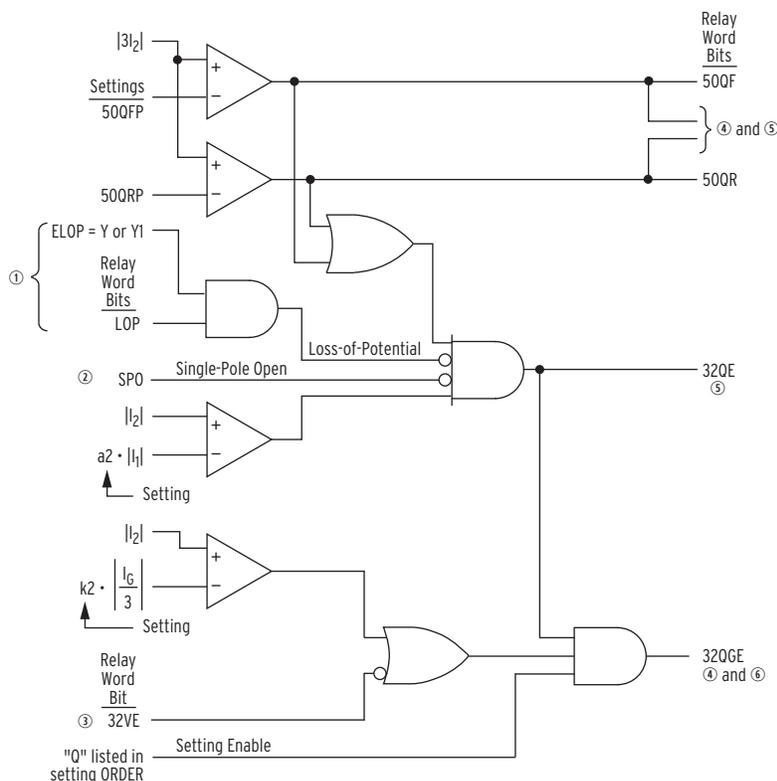
① From Figure 4.50; ② from Figure 5.5; ③ from Figure 4.53; ④ to Figure 4.55; ⑤ to Figure 4.59; ⑥ to Figure 4.54.

Figure 4.52   Directional Element Enables (32QE and 32QGE) Logic for Negative-Sequence Voltage-Polarized Directional Elements

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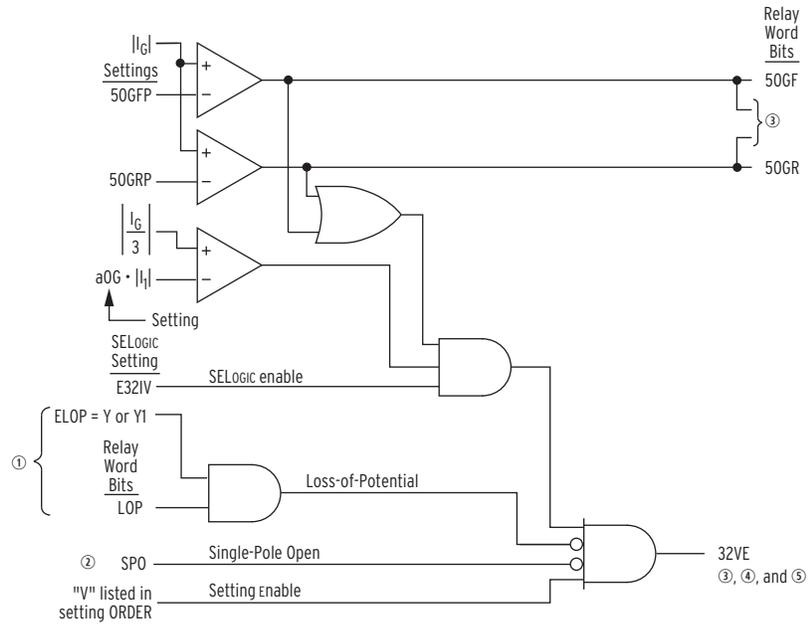
① From Figure 4.50; ② from Figure 5.5; ③ to Figure 4.56; ④ to Figure 4.52; ⑤ to Figure 4.54.

Figure 4.53   Directional Element Enable (32VE) Logic for Zero-Sequence Voltage-Polarized Directional Elements
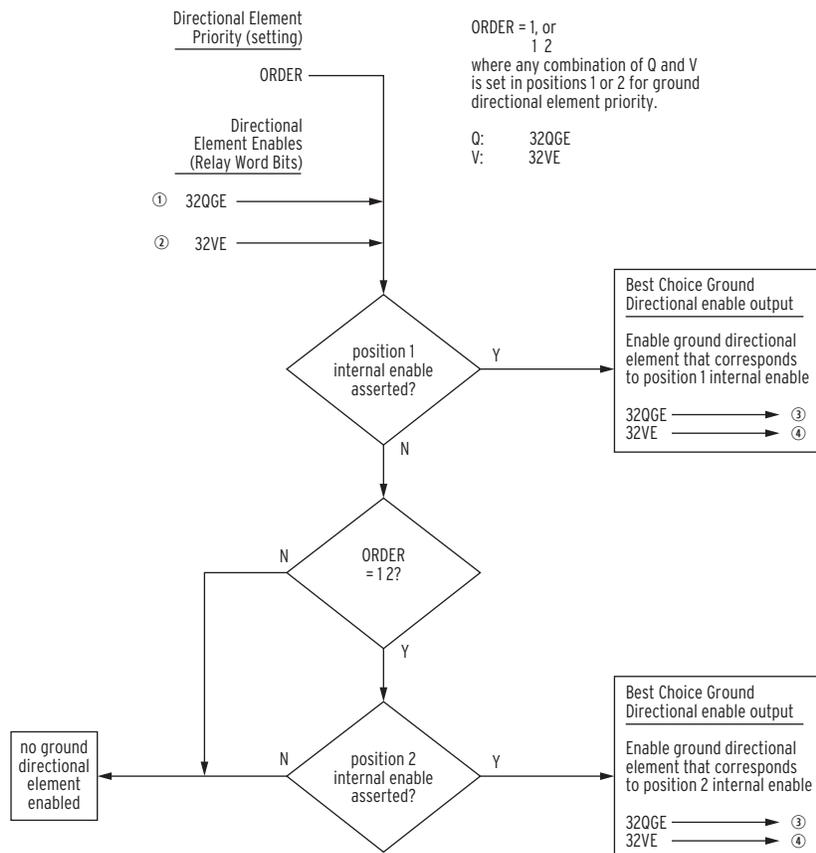
① From Figure 4.52; ② from Figure 4.53; ③ to Figure 4.55; ④ to Figure 4.56.

Figure 4.54   Best Choice Ground Directional Logic
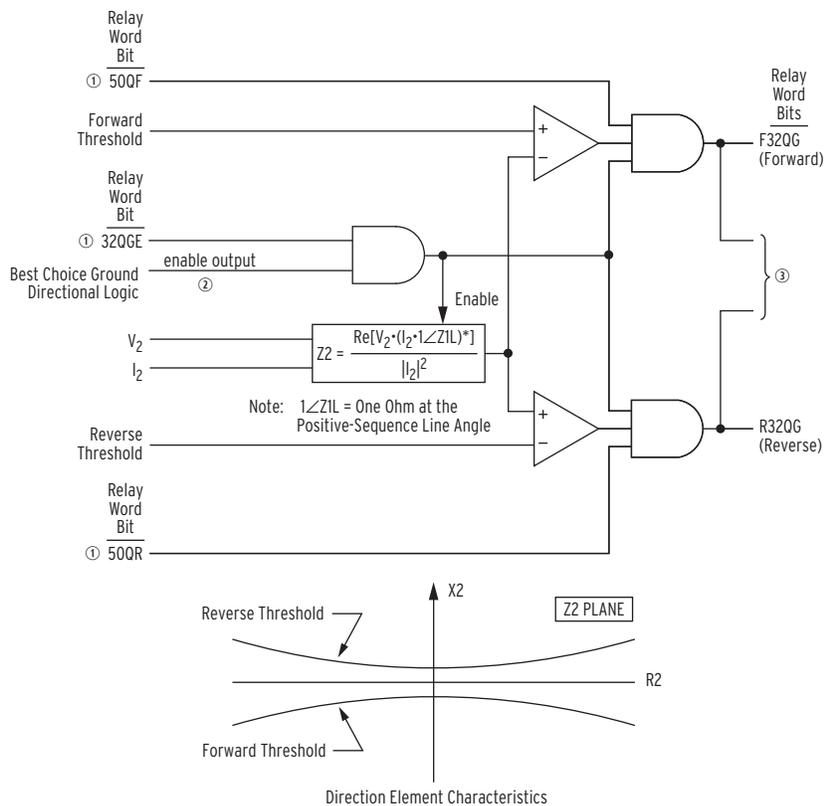
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Forward Threshold:

If Z2F Setting ≤ 0, Forward Threshold = $0.75 \cdot Z2F - 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

If Z2F Setting > 0, Forward Threshold = $1.25 \cdot Z2F - 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

Reverse Threshold:

If Z2R Setting ≥ 0, Reverse Threshold = $0.75 \cdot Z2R + 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

If Z2R Setting < 0, Reverse Threshold = $1.25 \cdot Z2R + 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

① From Figure 4.52; ② from Figure 4.54; ③ to Figure 4.57.

Figure 4.55   Negative-Sequence Voltage-Polarized Directional Element for Ground Overcurrent Elements

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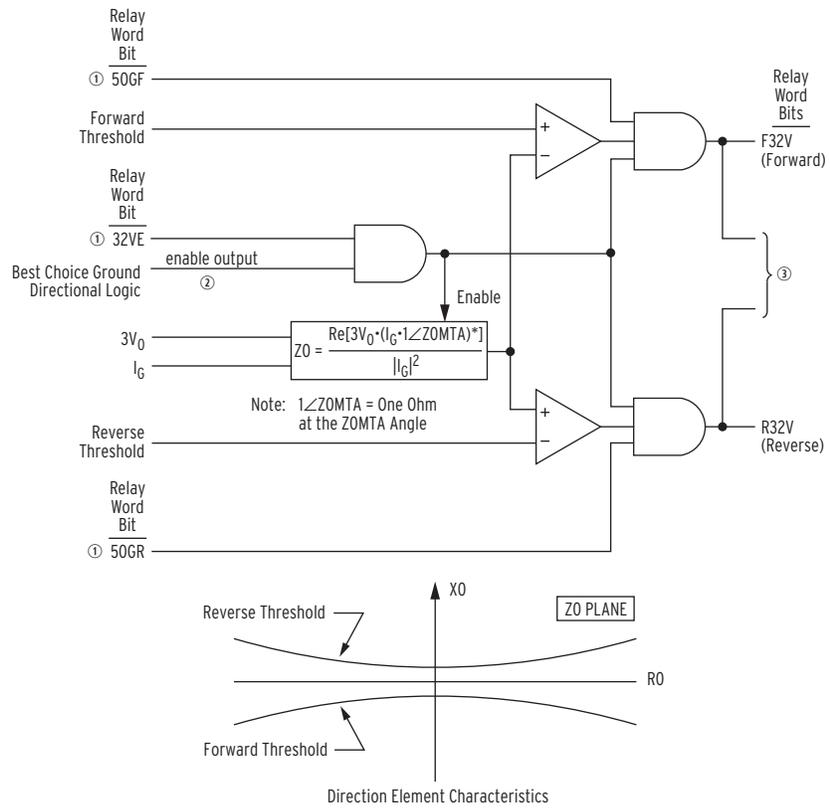
Forward Threshold:

$$\text{If Z0F Setting} \leq 0, \text{ Forward Threshold} = 0.75 \cdot \text{Z0F} - 0.25 \cdot \left| \frac{V_0}{I_0} \right|$$

$$\text{If Z0F Setting} > 0, \text{ Forward Threshold} = 1.25 \cdot \text{Z0F} - 0.25 \cdot \left| \frac{V_0}{I_0} \right|$$

Reverse Threshold:

$$\text{If Z0R Setting} \geq 0, \text{ Reverse Threshold} = 0.75 \cdot \text{Z0R} + 0.25 \cdot \left| \frac{V_0}{I_0} \right|$$

$$\text{If Z0F Setting} < 0, \text{ Reverse Threshold} = 1.25 \cdot \text{Z0R} + 0.25 \cdot \left| \frac{V_0}{I_0} \right|$$

① From Figure 4.53; ② from Figure 4.54; ③ to Figure 4.57.

Figure 4.56   Zero-Sequence Voltage-Polarized Directional Element for Ground Overcurrent Elements
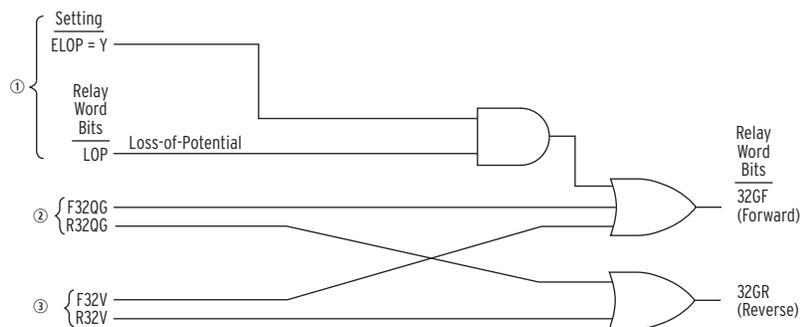
① From Figure 4.50; ② from Figure 4.55; ③ from Figure 4.56.

Figure 4.57   Routing of Directional Elements for Ground Directional Elements

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Directional Control for Negative-Sequence and Phase Overcurrent Elements

Setting E32 enables directional control for overcurrent elements. Setting E32 and other directional control settings are described in *Directional Control Settings on page 4.89*.

The negative-sequence voltage-polarized directional element controls the negative-sequence overcurrent elements. Negative-sequence voltage-polarized and positive-sequence voltage-polarized directional elements control the phase overcurrent elements. *Figure 4.58* gives an overview of how the negative-sequence voltage-polarized and positive-sequence voltage-polarized directional elements are enabled and routed to control the negative-sequence and phase overcurrent elements.
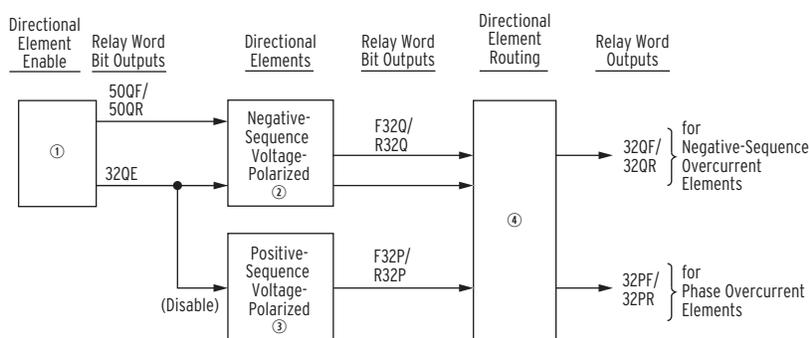
① Figure 4.52; ② Figure 4.59; ③ Figure 4.60; ④ Figure 4.61.

Figure 4.58   General Logic Flow of Directional Control for Negative-Sequence Overcurrent and Phase Overcurrent Elements

Directional Element Enable

Refer to *Figure 4.52* and *Figure 4.58*.

The Relay Word bit 32QE enables the negative-sequence voltage-polarized directional element and disables the positive-sequence voltage-polarized directional element. The positive-sequence voltage-polarized directional element is only operative for three-phase faults, where negative-sequence current (I_2) is minimal or nonexistent, compared to positive-sequence current (I_1; see the a2 setting factor in *Figure 4.52*).

Note in *Figure 4.52* that if:

➤ enable setting ELOP := Y or Y1 and a loss-of-potential condition occurs (Relay Word bit LOP asserts; see *Figure 4.50*)

➤ or a single-pole open condition occurs (Relay Word bit SPO asserts; see *Figure 5.5*)

then the 32QE directional element enable is disabled. The loss-of-potential condition (Relay Word bit LOP) also applies to the positive-sequence voltage-polarized directional element (*Figure 4.60*) and a single-pole open condition (or lack thereof) is effectively checked for in *Figure 4.60* with three-phase overcurrent element 50P32. The 32QE directional element enable also has current signal thresholds that must be met (settings 50QFP/50QRP).

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Figure 4.52 has extra directional element enable 32QGE, which is used in the directional element logic that controls the ground overcurrent elements (see *Figure 4.55*).

The settings involved with 32QE in *Figure 4.52* (e.g., setting a2) are explained in *Directional Control Settings on page 4.89*.

Directional Elements

Refer to *Figure 4.58*, *Figure 4.59*, and *Figure 4.60*.

For an unbalanced fault, presuming sufficient negative-sequence current signal is present (Relay Word bit 50QF or 50QR asserted), an impedance-based directional calculation is then made in *Figure 4.59*. The technical paper *Negative-Sequence Impedance Directional Element* by Bill Fleming goes into more detail on this impedance-based calculation for the negative-sequence voltage-polarized directional element (paper available from website: selinc.com/literature/technical-papers/).

The negative-sequence voltage-polarized directional element operates for unbalanced faults while the positive-sequence voltage-polarized directional element operates for three-phase faults.

VPOLV in *Figure 4.60* indicates that there is sufficient positive-sequence voltage for the positive-sequence voltage-polarized directional element to operate. If there is a three-phase fault close-in to the SEL-651R-2, all three phase voltages depress to zero magnitude. In such a scenario, the SEL-651R-2 then internally generates a positive-sequence memory voltage for a time period of about 30 cycles or more after the voltage depression. This memory voltage is used in the internal phase-to-phase distance-type elements indicated in *Figure 4.60* to keep directional decisions going for several more cycles in the face of such a voltage depression. VPOLV remains asserted until this memory voltage expires.

Note in *Figure 4.60* that the assertion of ZLOAD disables the positive-sequence voltage-polarized directional element. ZLOAD asserts when the relay is operating in a user-defined load region (see *Figure 4.48*).

Directional Element Routing

Refer to *Figure 4.58* and *Figure 4.61*.

The directional element outputs are routed to the forward (Relay Word bits 32QF and 32PF) and reverse (Relay Word bits 32QR and 32PR) logic points, for use in controlling negative-sequence and phase overcurrent elements.

Table 4.25 and accompanying text give examples of directional control implementation (i.e., by using the outputs of *Figure 4.57* and *Figure 4.61* in overcurrent element torque-control settings and other SELOGIC settings to realize desired directional control).

Loss of Potential

Note in *Figure 4.61* that if *both* the following are true:

➤ enable setting ELOP := Y

➤ a loss-of-potential condition occurs (Relay Word bit LOP asserts)

then the forward logic points (Relay Word bits 32QF and 32PF) assert to logical 1, thus enabling elements that are set direction forward. These direction forward elements effectively become nondirectional and provide protection during a loss-of-potential condition.

As detailed previously (in *Figure 4.52* and *Figure 4.60*), voltage-based directional elements are disabled during a loss-of-potential condition. Thus, the overcurrent elements controlled by these voltage-based directional elements are also disabled. But this disable condition is overridden for the overcurrent elements set direction forward if setting ELOP := Y, as explained above.
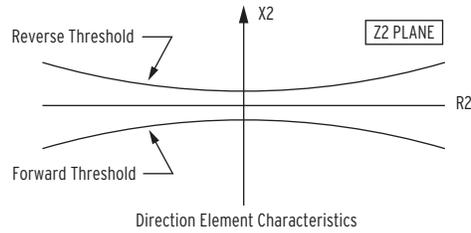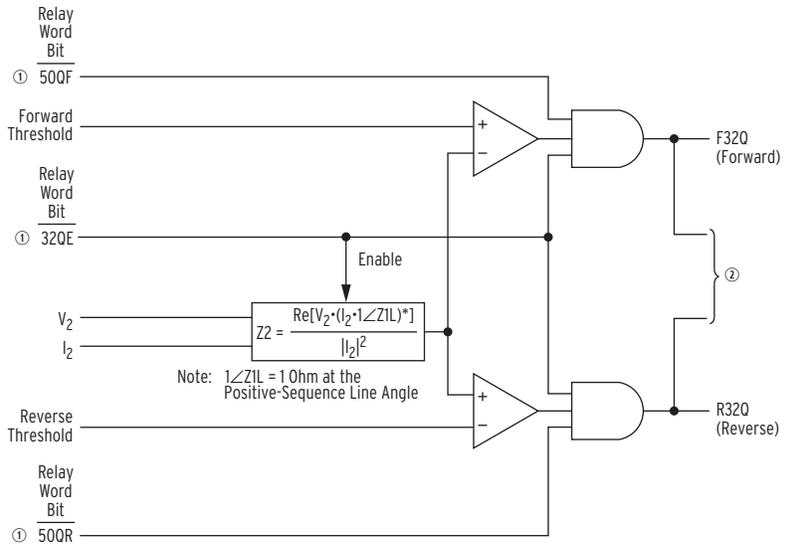
Forward Threshold:

If Z2F Setting ≤ 0, Forward Threshold $= 0.75 \cdot Z2F - 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

If Z2F Setting > 0, Forward Threshold $= 1.25 \cdot Z2F - 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

Reverse Threshold:

If Z2R Setting ≥ 0, Reverse Threshold $= 0.75 \cdot Z2R + 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

If Z2R Setting < 0, Reverse Threshold $= 1.25 \cdot Z2R + 0.25 \cdot \left| \dfrac{V_2}{I_2} \right|$

① From Figure 4.52; ② to Figure 4.61.

Figure 4.59   Negative-Sequence Voltage-Polarized Directional Element for Negative-Sequence and Phase Overcurrent Elements

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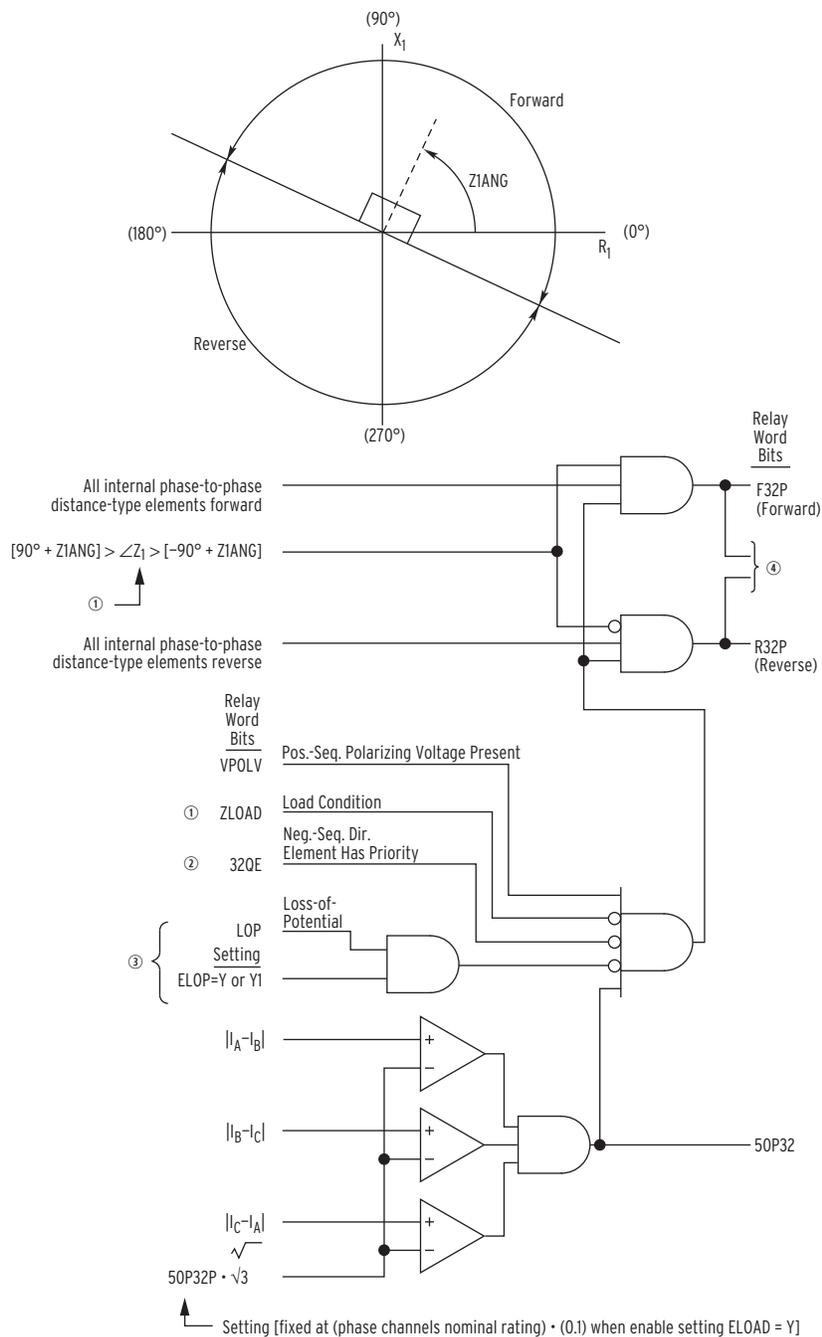
① From Figure 4.48; ② from Figure 4.52; ③ from Figure 4.50; ④ to Figure 4.61.

Figure 4.60   Positive-Sequence Voltage-Polarized Directional Element for Phase Overcurrent Elements

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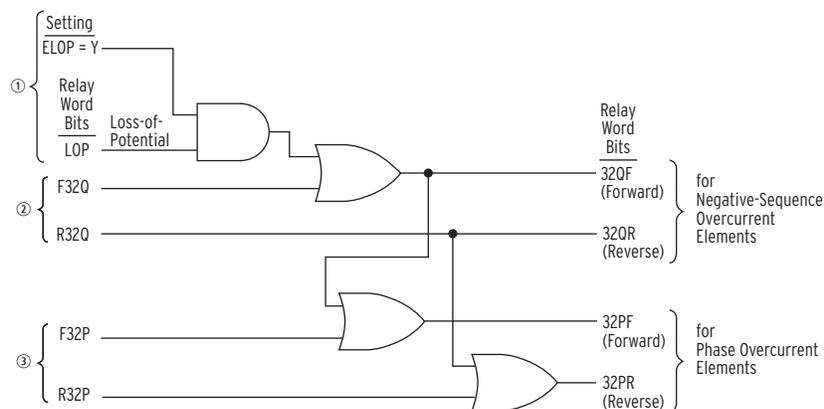
① From Figure 4.50; ② from Figure 4.59; ③ from Figure 4.60.

Figure 4.61   Routing of Directional Elements to Negative-Sequence and Phase Overcurrent Elements

Directional Control Settings

The directional control for overcurrent elements is configured by making directional control enable setting E32. Setting E32 has setting choices:

➤ Y (All directional control settings made manually)

➤ N (Disable directional control)

➤ AUTO or AUTO2 (Sets most of the directional control settings automatically)

The directional elements require that three-phase voltages be connected to either the VY- or VZ-voltage terminals, as designated by Global setting VSELECT := VY or VZ. If VSELECT := OFF, enable setting E32 is forced to N and cannot be changed.

Settings Made Automatically

If the directional control enable setting E32 is set:

E32 := **AUTO** or **AUTO2**

then the following directional control settings are calculated and set automatically:

Z2F, Z2R, 50QFP, 50QRP, a2, k2, 50GFP, 50GRP, a0G, Z0F, Z0R, and Z0MTA

AUTO VS. AUTO2
The only difference between E32 := AUTO and E32 := AUTO2 is how settings Z2F, Z2R, Z0F, and Z0R are calculated and set automatically. E32 := AUTO2 is preferred for making automatic settings. See Z2F and Z2R Set Automatically and Z0F and Z0R Set Automatically for details.

Once these settings are calculated automatically, they can only be modified if the user goes back and changes the directional control enable setting to E32 := Y. The remaining directional control settings are not set automatically if setting E32 := AUTO or AUTO2. They have to be set by the user, whether setting E32 := AUTO, AUTO2, or Y. These settings are:

ORDER, 50P32P, and E32IV (E32IV is a SELOGIC setting)

All these settings are explained in detail in the remainder of this subsection.

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Not all these directional control settings (set automatically or by the user) are used in every application. The following are particular directional control settings that are hidden/not made for particular conditions:

Settings Hidden/Not Made:	For Condition:
50P32P	setting ELOAD := Y
50GFP, 50GRP, a0G, Z0F, Z0R, Z0MTA, E32IV	setting ORDER does not contain V

Settings

ORDER–Ground Directional Element Priority Setting

Setting Range:

Q (Negative-sequence voltage-polarized directional element)

V (Zero-sequence voltage-polarized directional element)

OFF (Disable ground directional control)

Setting ORDER can be set with any combination of Q and V. The order in which these directional elements are listed determines the priority in which they operate to provide Best Choice Ground Directional logic control. See *Figure 4.54*.

For example, if setting:

ORDER := **QV**

then the first listed directional element (Q = negative-sequence voltage-polarized directional element; see *Figure 4.55*) is the first priority directional element to provide directional control for the ground overcurrent elements.

If the negative-sequence voltage-polarized directional element is not operable (i.e., it does not have sufficient operating quantity as indicated by its internal enable, 32QGE, not being asserted), then the second listed directional element (V = zero-sequence voltage-polarized directional element; see *Figure 4.56*) provides directional control for the ground overcurrent elements.

Another example, if setting:

ORDER := **V**

then the zero-sequence voltage-polarized directional element (V = zero-sequence voltage-polarized directional element; see *Figure 4.56*) provides directional control for the ground overcurrent elements all the time.

Setting ORDER can be set with any element combination (i.e., ORDER := QV, ORDER := VQ, ORDER := V, ORDER := Q, or ORDER := OFF).

50P32P-Phase Directional Element Three-Phase Current Pickup

Setting Range:

0.10–2.00 A secondary

The 50P32P setting is set to pick up for all three-phase faults that need to be covered by the phase overcurrent elements. It supervises the positive-sequence voltage-polarized directional elements F32P and R32P (see *Figure 4.60*).

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If the load-encroachment logic is enabled (enable setting ELOAD := Y), then setting 50P32P is not made or displayed, but is fixed internally at:

0.1 A secondary

Z2F–Forward Directional Z2 Threshold
Z2R–Reverse Directional Z2 Threshold

Setting Range:

–640.00 to 640.00 Ω secondary

Z2F and Z2R are used to calculate the Forward and Reverse Thresholds, respectively, for the negative-sequence voltage-polarized directional elements (see *Figure 4.55* and *Figure 4.59*).

If configuration setting E32 := Y, settings Z2F and Z2R (negative-sequence impedance values) are calculated by the user and entered by the user, but setting Z2R must be greater in value than setting Z2F by 0.10 Ω secondary.

Figure 4.62 and *Figure 4.63* and supporting text concern the zero-sequence impedance network, relay polarity, and the derivation of settings Z0F and Z0R. The same general approach outlined for deriving settings Z0F and Z0R can also be applied to deriving settings Z2F and Z2R in the negative-sequence impedance network. If the basis for Z2F and Z2R values (Ω secondary) is primary impedance values (Ω primary), convert these primary impedance values to secondary impedance values by using *Equation 9.16* (Global setting VSELECT := VY) or *Equation 9.17* (Global setting VSELECT := VZ).

Z2F and Z2R Set Automatically

If configuration setting E32 := AUTO, settings Z2F and Z2R (negative-sequence impedance values) are calculated automatically, using the positive-sequence line impedance magnitude setting Z1MAG as follows:

Z2F := **Z1MAG/2** (Ω secondary)

Z2R := **Z1MAG/2 + 1.00** (Ω secondary)

If configuration setting E32 := AUTO2, the settings are then set as follows:

Z2F := **–1.5** (Ω secondary; preferred setting for most scenarios)

Z2R := **1.5** (Ω secondary; preferred setting for most scenarios)

These automatic settings for Z2F and Z2R (when E32 := AUTO2) are the preferred settings. For controls with older firmware that does not include the E32 := AUTO2 option, these settings can be set directly as such (Z2F := –1.5 and Z2R := 1.5) when setting E32 := Y.

For more information on these preferred Z2F and Z2R settings, see the following technical paper (available at selinc.com):

Fundamentals and Improvements for Directional Relays by Karl Zimmerman and David Costello (Schweitzer Engineering Laboratories, Inc.)

In particular, see the following pertinent discussions in Section III. FIELD CASE STUDIES:

➤ Subsection A. Low V2 Magnitude Challenges Automatic Thresholds

➤ Subsection D. New Automatic Settings Recommendation

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These subsections assume 5 A nominal secondary current inputs, while the SEL-651R-2 has 1 A nominal secondary current inputs. Thus, *Figure 15* and *Figure 20* in these particular subsections show forward and reverse settings that differ from the preferred settings for the SEL-651R-2 (Z2F := –1.5 and Z2R := 1.5) by a factor of five.

One of the only exceptions to using these preferred settings (Z2F := –1.5 and Z2R := 1.5) is if there is an extremely strong source behind the SEL-651R-2. If the absolute value of the equivalent negative-sequence source impedance behind the SEL-651R-2 is less than 2.5 Ω secondary (again, the reference paper shows a factor of five difference for this value), this is indicative of a strong source, and settings Z2F and Z2R should both be set as positive values with Z2F < Z2R. This is similar to the automatic setting of Z2F and Z2R when E32 := AUTO.

50QFP-Forward Directional Negative-Sequence Current Pickup
50QRP-Reverse Directional Negative-Sequence Current Pickup

Setting Range:

0.05–1.00 A secondary

The 50QFP setting ($3I_2$ current value) is the pickup for the forward fault detector 50QF of the negative-sequence voltage-polarized directional elements (see *Figure 4.52*). Ideally, the setting is above normal load unbalance and below the lowest expected negative-sequence current magnitude for unbalanced forward faults.

The 50QRP setting ($3I_2$ current value) is the pickup for the reverse fault detector 50QR of the negative-sequence voltage-polarized directional elements (see *Figure 4.52*). Ideally, the setting is above normal load unbalance and below the lowest expected negative-sequence current magnitude for unbalanced reverse faults.

50QFP and 50QRP Set Automatically

If configuration setting E32 := AUTO or AUTO2, settings 50QFP and 50QRP are set automatically at:

50QFP := **0.10 A secondary**

50QRP := **0.05 A secondary**

a2−Positive-Sequence Current Restraint Factor, $|I_2|/|I_1|$

Setting Range:

0.02–0.50 (unitless)

Refer to *Figure 4.52*.

The a2 factor increases the security of the negative-sequence voltage-polarized directional elements. It prevents the elements from operating for negative-sequence current (i.e., system unbalance), which can circulate as a result of line asymmetries, CT saturation during three-phase faults, or other events.

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a2 Set Automatically

If configuration setting E32 := AUTO or AUTO2, setting a2 is set
automatically at:

a2 := **0.1**

For setting a2 := 0.1, the negative-sequence current (I_2) magnitude has to be
greater than 1/10 of the positive-sequence current (I_1) magnitude in order for
the negative-sequence voltage-polarized directional elements to be enabled
($|I_2| > 0.1 \cdot |I_1|$).

k2–Zero-Sequence Current Restraint Factor, $|I_2|/|I_0|$

Setting Range:

0.10–1.20 (unitless)

Note the directional enable logic outputs in *Figure 4.52*:

➤ 32QE (enable for the negative-sequence voltage-polarized
directional element that controls the negative-sequence and
phase overcurrent elements)

➤ 32QGE (enable for the negative-sequence voltage-polarized
directional element that controls the ground overcurrent
elements)

Factor k2 is an additional threshold to be met by directional element enable
32QGE if the zero-sequence voltage-polarized directional element enable
32VE is already asserted. The negative-sequence current (I_2) magnitude has to
be greater than the zero-sequence current (I_0) magnitude multiplied by k2 in
order for the 32QGE enable (and following negative-sequence voltage-
polarized directional element in *Figure 4.55*) to be enabled:

$$\left|I_2\right| > k2 \cdot \left|I_0\right|$$

Equation 4.10

This check ensures that the relay uses the most robust analog quantities in
making directional decisions for the ground overcurrent elements.

If directional element enable 32VE is deasserted, then factor k2 (and its
effective threshold) is not a requirement for directional element enable
32QGE operation.

Setting k2 is often derived by using zero-sequence current (I_0) values and
negative-sequence current (I_2) values from system studies, load profiles, or
metering. Make sure these current values are on the same base. The easiest
way to ensure the same base is to use primary values.

The zero-sequence current ($I_0 = I_G/3$; I_G is the ground current) source can
switch between residual ground ($I_G = 3I_0 = I_A + I_B + I_C$) and neutral ground
($I_G = I_N$; channel IN) for some scenarios (see *Table 4.23*). This apparent
switching of zero-sequence current base (if CTR ≠ CTRN) is handled
internally for setting k2 applied in *Figure 4.52*.

k2 Set Automatically

If configuration setting E32 := AUTO or AUTO2, setting k2 is set
automatically at:

k2 := **0.2**

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For setting k2 := 0.2, the negative-sequence current (I_2) magnitude has to be greater than 1/5 of the zero-sequence current (I_0) magnitude in order for the negative-sequence voltage-polarized directional elements to be enabled ($|I_2| >$ 0.2 • $|I_0|$). Again, this further threshold requirement presumes enable 32VE is asserted, as described previously.

50GFP-Forward Directional Ground Current Pickup
50GRP-Reverse Directional Ground Current Pickup

Setting Range:

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

    0.005–1.00 A secondary
        on channel IN base (see Note), when Global setting EGNDSW := Y and Group setting CTR = CTRN

    0.005–[1.00 • (CTR/CTRN)] A secondary
        on channel IN base, when Global setting EGNDSW := Y and Group setting CTR ≠ CTRN

    0.010–1.00 A secondary
        on IA, IB, IC base, when Global setting EGNDSW := N

If preceding setting ORDER does not contain V (the zero-sequence voltage-polarized directional element is not enabled), then settings 50GFP and 50GRP are not made or displayed.

The 50GFP setting (I_G ground current value) is the pickup for the forward fault detector 50GF of the zero-sequence voltage-polarized directional element (see *Figure 4.53*). Ideally, the setting is above normal load unbalance and below the lowest expected zero-sequence current magnitude for unbalanced forward faults.

The 50GRP setting (I_G ground current value) is the pickup for the reverse fault detector 50GR of the zero-sequence voltage-polarized directional element (see *Figure 4.53*). Ideally, the setting is above normal load unbalance and below the lowest expected zero-sequence current magnitude for unbalanced reverse faults.

50GFP and 50GRP Set Automatically

If configuration setting E32 := AUTO or AUTO2, settings 50GFP and 50GRP are set automatically at:

    50GFP := **0.100 A secondary**
    50GRP := **0.050 A secondary**

a0G–Positive-Sequence Current Restraint Factor, $|I_0|/|I_1|$

Setting Range:

    0.001–0.500 (unitless)

If preceding setting ORDER does not contain V (the zero-sequence voltage-polarized directional element is not enabled), then setting a0G is not made or displayed.

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Refer to *Figure 4.53*.

The a0G factor increases the security of the zero-sequence voltage-polarized directional element. It prevents the elements from operating for zero-sequence current (i.e., system unbalance), which can circulate as a result of line asymmetries, CT saturation during three-phase faults, or other events.

Setting a0G is often derived by using zero-sequence current (I_0) values and positive-sequence current (I_1) values from system studies, load profiles, or metering. Make sure these current values are on the same base. The easiest way to ensure the same base is to use primary values.

The zero-sequence current ($I_0 = I_G/3$; I_G is the ground current) source can switch between residual ground ($I_G = 3I_0 = I_A + I_B + I_C$) and neutral ground ($I_G = I_N$; channel IN) for some scenarios (see *Table 4.23*). This apparent switching of zero-sequence current base (if CTR ≠ CTRN) is handled internally for setting a0G applied in *Figure 4.53*.

a0G Set Automatically

If configuration setting E32 := AUTO or AUTO2, setting a0G is set automatically at:

a0G := **0.1**

For setting a0G := 0.1, the zero-sequence current (I_0) magnitude has to be greater than 1/10 of the positive-sequence current (I_1) magnitude in order for the zero-sequence voltage-polarized directional element to be enabled ($|I_0| > 0.1 \cdot |I_1|$).

Z0F-Forward Directional Z0 Threshold
Z0R-Reverse Directional Z0 Threshold

Setting Range:

–640.00 to 640.00 Ω secondary

If preceding setting ORDER does not contain V (the zero-sequence voltage-polarized directional element is not enabled), then settings Z0F and Z0R are not made or displayed.

Z0F and Z0R are used to calculate the Forward and Reverse Thresholds, respectively, for the zero-sequence voltage-polarized directional element (see *Figure 4.56*).

If configuration setting E32 := Y, settings Z0F and Z0R (zero-sequence impedance values) are calculated by the user and entered by the user, but setting Z0R must be greater in value than setting Z0F by 0.1 Ω secondary.

If the basis for Z0F and Z0R values (Ω secondary) is primary impedance values (Ω primary), convert these primary impedance values to secondary impedance values, by using *Equation 9.16* (Global setting VSELECT := VY) or *Equation 9.17* (Global setting VSELECT := VZ).

The zero-sequence current ($I_0 = I_G/3$; I_G is the ground current) source can switch between residual ground ($I_G = 3I_0 = I_A + I_B + I_C$) and neutral ground ($I_G = I_N$; channel IN) for some scenarios (see *Table 4.23*). This apparent switching of zero-sequence current base (if CTR ≠ CTRN) is handled internally for settings Z0F and Z0R applied in the bottom equations in *Figure 4.56*.

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ZOF and ZOR Set Automatically

If configuration setting E32 := AUTO, settings Z0F and Z0R (zero-sequence impedance values) are calculated automatically, using the zero-sequence line impedance magnitude setting Z0MAG as follows:

Z0F := **Z0MAG/2** (Ω secondary)

Z0R := **Z0MAG/2 + 1.00** (Ω secondary)

If configuration setting E32 := AUTO2, the settings are then set as follows:

Z0F := **-1.5** (Ω secondary; preferred setting for most scenarios)

Z0R := **1.5** (Ω secondary; preferred setting for most scenarios)

These automatic settings for Z0F and Z0R (when E32 := AUTO2) are the preferred settings. For controls with older firmware that does not include the E32 := AUTO2 option, these settings can be set directly as such (Z0F := –1.5 and Z0R := 1.5) when setting E32 := Y.

Refer to the technical paper reference and discussion that follows in the preceding *Z2F and Z2R Set Automatically* subsection. Though discussing negative-sequence impedance networks, this information is still generally applicable to zero-sequence impedance networks and settings Z0F and Z0R.

Deriving ZOF and ZOR Settings

Figure 4.62 shows the voltage and current polarity for an SEL-651R-2 in a zero-sequence impedance network (the same approach can also be instructive for negative-sequence impedance analysis using settings Z2F and Z2R). For a forward fault, the SEL-651R-2 effectively sees the sequence impedance behind it as:

$Z_M = V_0/(-I_0) = -(V_0/I_0)$ $V_0/I_0 = -Z_M$ (what the relay sees for a forward fault)

For a reverse fault, the SEL-651R-2 effectively sees the sequence impedance in front of it:

$Z_N = V_0/I_0$ $V_0/I_0 = Z_N$ (what the relay sees for a reverse fault)

If the system in *Figure 4.62* is a solidly grounded system (mostly inductive; presume uniform system angle), the impedance plot (in the R + jX plane) would appear as in *Figure 4.63a*, with resultant Z0F and Z0R settings as in *Figure 4.63b*. The zero-sequence line angle noted in *Figure 4.63a* ($\angle$Z0MTA) is the same angle found in *Figure 4.56* (in the equation box with the Enable line).

The preceding method of automatically making settings Z0F and Z0R (where both Z0F and Z0R are positive values; still Z0R > Z0F) usually suffices for mostly inductive systems—*Figure 4.62* and *Figure 4.63* just provide a theoretic background.

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Zero-Sequence Reference Bus
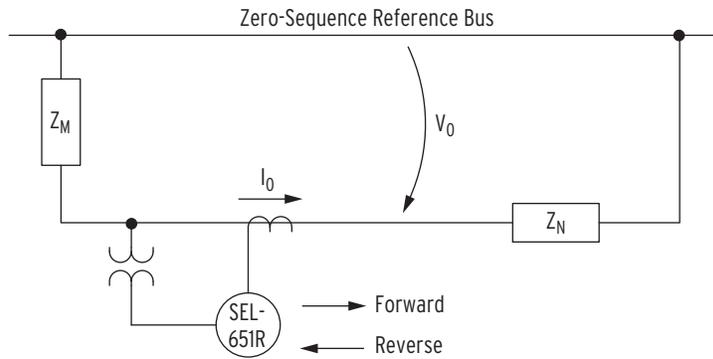
Figure 4.62   Zero-Sequence Impedance Network and Relay Polarity

(a) Impedance Plot

(b) ZOF and ZOR Settings
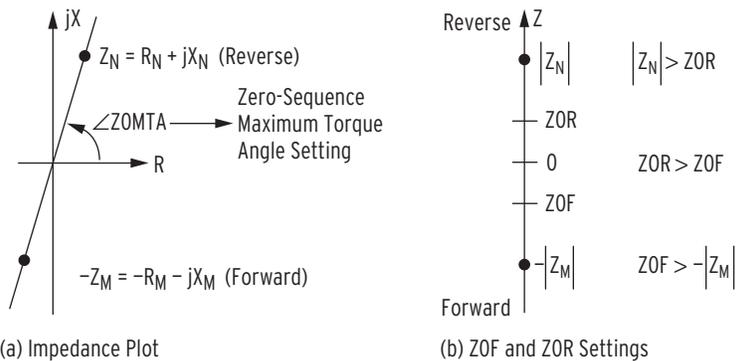
Figure 4.63   Zero-Sequence Impedance Plot for Solidly Grounded, Mostly Inductive System

Z0MTA–Zero-Sequence Maximum Torque Angle

Setting Range:

–90.00 to –5.00 degrees and 5.00 to 90.00 degrees

The Z0MTA setting is at the heart of the zero-sequence voltage-polarized directional element of *Figure 4.56*. Z0MTA is only available if both of the following conditions are true:

➤ enable setting E32 := Y, AUTO, or AUTO2

➤ setting ORDER contains the value "V"

Otherwise, Z0MTA is hidden and of no consequence. Z0MTA can be set one of two ways:

STILL MAKE SETTING Z0ANG WHEN E32 := Y
Even though setting Z0MTA is not automatically set equal to the value of setting Z0ANG when enable setting E32 := Y, setting Z0ANG should still be made for fault location purposes.

➤ If enable setting E32 := AUTO or AUTO2, then Z0MTA is automatically set to the value of setting Z0ANG (the setting range of Z0MTA encompasses that of setting Z0ANG).

As long as E32 := AUTO or AUTO2, Z0MTA can be seen, but not changed. This automatic setting mode is primarily for traditional applications, where the angle of the zero-sequence system impedance behind the control is deemed to be essentially the same as the angle of the zero-sequence line impedance in front of it (see *Figure 4.62* and *Figure 4.63(a)*).

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➤ If enable setting E32 := Y, then Z0MTA is set independently within its setting range.

This option is primarily used for such applications as low-impedance grounded systems, which are discussed in the balance of this subsection.

The distribution system in *Figure 4.64* is low-impedance grounded at the substation by either of the following methods:

➤ a resistance in the transformer bank neutral

➤ a grounding bank with a resistance in its broken-delta secondary (effectively making it a neutral resistance)
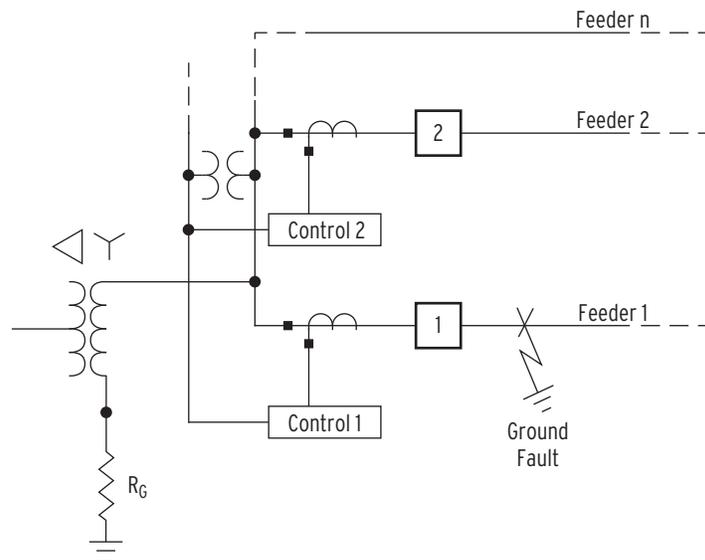
Figure 4.64   Low-Impedance Grounded Distribution System With a Ground Fault on Feeder 1

A grounding bank is installed if low-impedance grounding is desired at a substation and the transformer bank is to remain ungrounded. *Figure 4.64* also shows a ground fault out on Feeder 1 (a forward fault from the perspective of Control 1). This example assumes that SEL-651R-2 recloser controls (Control 1, Control 2, etc.) are installed at feeder positions in a distribution substation.

Figure 4.65 shows the resultant zero-sequence impedance network for the ground fault on Feeder 1 in *Figure 4.64*. V_0 in *Figure 4.65* is the zero-sequence voltage seen by all the controls connected to the distribution substation bus three-phase voltage.

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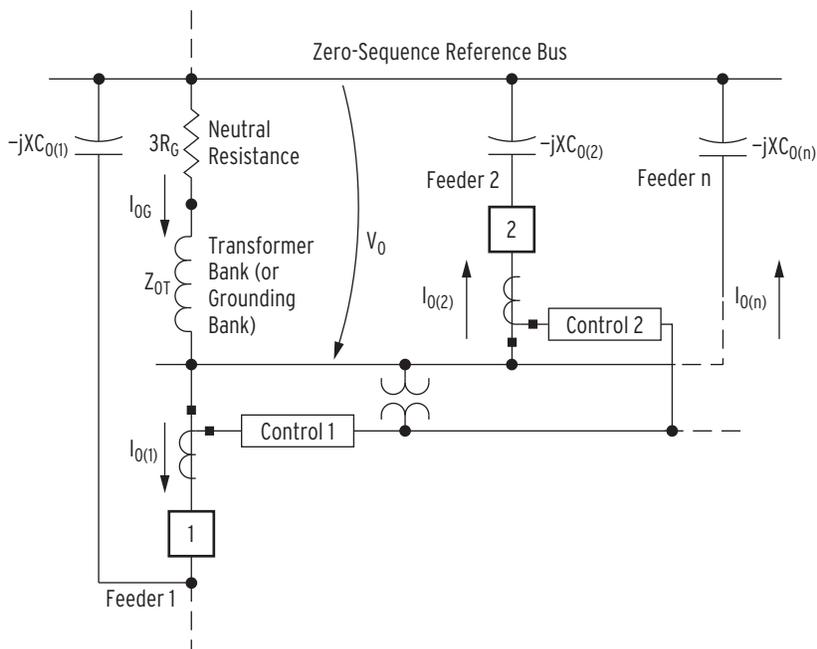
Figure 4.65   Zero-Sequence Impedance Network for Low-Impedance Grounded Distribution System With a Ground Fault on Feeder 1

Impedance definitions for *Figure 4.65*:

➤ $-jXC_{0(1)}$ = zero-sequence capacitive reactance for Feeder 1 (the faulted feeder)

➤ $-jXC_{0(2)}$ = zero-sequence capacitive reactance for Feeder 2

➤ $-jXC_{0(n)}$ = zero-sequence capacitive reactance for the cumulative other feeders

➤ Z_{0T} = transformer bank (or grounding bank) zero-sequence impedance

➤ R_G = neutral resistance, connected to transformer bank (or grounding bank)

The zero-sequence capacitive reactance values of the feeders are much larger than the zero-sequence feeder line impedances, so the zero-sequence feeder line impedances are ignored in this fault analysis.

Current definitions for *Figure 4.65*:

➤ $I_{0(1)}$ = zero-sequence current flow for Feeder 1 (forward direction for Control 1)

➤ $I_{0(2)}$ = zero-sequence current flow for Feeder 2 (forward direction for Control 2)

➤ $I_{0(n)}$ = zero-sequence current flow for cumulative other feeders (forward direction for controls on other feeders)

➤ I_{0G} = zero-sequence current flow through neutral resistance R_G and transformer bank (or grounding bank)

Presume there is a substantial capacitance-creating network (e.g., underground cable) on the individual feeders. As cable capacitance increases, capacitive reactance decreases, allowing for increased capacitive current flow. For the ground fault in *Figure 4.64* (a reverse fault from the perspective of

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Control 2), Control 2 sees zero-sequence current $I_{0(2)}$ flow toward the zero-sequence capacitive reactance $-jXC_{0(2)}$. If this current flow is high enough, a false trip may occur, unless otherwise prevented (e.g., by directional control).

Figure 4.66 plots the increase in zero-sequence current I_{0G} resulting from decreasing neutral resistance R_G.
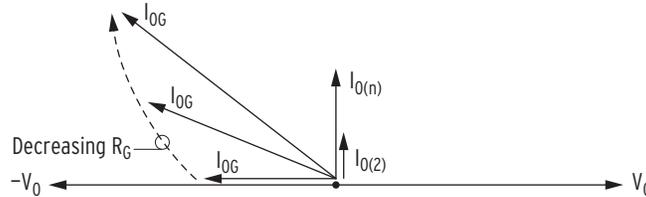
Figure 4.66   Decreasing Neutral Resistance R_G Results in Increasing Zero-Sequence Current I_{0G}

Vectorially add currents $I_{0(2)}$ and $I_{0(n)}$ to I_{0G} (per direction in *Figure 4.65*):

$$I_{0(1)} = I_{0G} - I_{0(2)} - I_{0(n)}$$

Figure 4.67 plots the increase in zero-sequence current $I_{0(1)}$ (seen by Control 1) resulting from decreasing neutral resistance R_G.
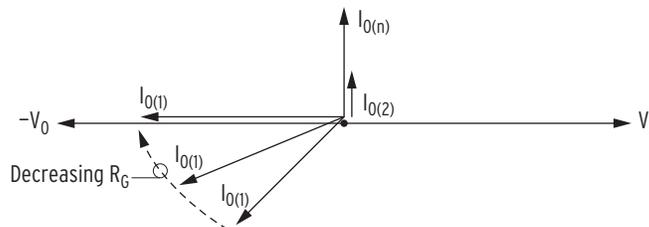
Figure 4.67   Decreasing Neutral Resistance R_G Results in Increasing Zero-Sequence Current $I_{0(1)}$ (Seen by Control 1)

In *Figure 4.67*, the lowest magnitude of zero-sequence current $I_{0(1)}$ (at 225 degrees from zero-sequence voltage V_0) represents a high-resistance grounded system. The following (absolute value) comparisons are typically true for a high-resistance grounded system:

➤ $3R_G \gg Z_{0T}$ (ignore transformer bank [or grounding bank] impedance Z_{0T})

➤ $3R_G$ = resultant impedance from the parallel combination of zero-sequence capacitive reactance values $-jXC_{0(2)}$ and $-jXC_{0(n)}$ (the total capacitive reactance behind Control 1)

As neutral resistance R_G decreases, zero-sequence current $I_{0(1)}$ increases in *Figure 4.67*. The system is moving away from being a high-resistance grounded system toward being a low-resistance grounded system.

APPLY ZOMTA TO HIGH-RESISTANCE GROUNDED SYSTEM?
This example for the ZOMTA setting discussion addresses low-impedance grounded systems. A high-resistance grounded system (with its lower zero-sequence current values for ground fault conditions) requires that channel IN be connected to a separate current transformer, instead of in a factory-default residual connection with the phase current channels.

Such a separate current transformer would have the three primary phase wires running through its core, eliminating any false residual current (see Scenario 2 in Table 4.23). Such current transformer applications are often referred to by one of the following names: flux-summing, core-balance, zero-sequence, ground fault, or window current transformers.

Other settings (see Figure 4.53 and Figure 4.56) also have to be considered to make sure they are sensitive enough for a high-resistance grounded system application.

The technical paper referenced at the end of this subsection also discusses directional element applications for high-resistance grounded systems.

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The zero-sequence voltage/current vector values of *Figure 4.67* are converted (by using polarity and impedances in *Figure 4.65*) to the apparent zero-sequence impedances that the respective controls see, as plotted in *Figure 4.68*:

➤ Ground fault on Feeder 1 is in the forward direction for Control 1:

$V_0/(-I_{0(1)}) =$ parallel combination of zero-sequence impedance values $-jXC_{0(2)}$, $-jXC_{0(n)}$, and $3R_G + Z_{0T}$

$V_0/I_{0(1)} =$ $-$(parallel combination of zero-sequence impedance values $-jXC_{0(2)}$, $-jXC_{0(n)}$, and $3R_G + Z_{0T}$)

$V_0/I_{0(1)} =$ the negative value of the aggregate zero-sequence impedance behind Control 1

➤ Ground fault on Feeder 1 is in the reverse direction for Control 2:

$V_0/I_{0(2)} =$ $-jXC_{0(2)}$

$V_0/I_{0(2)} =$ the zero-sequence capacitive reactance for Feeder 2 in front of Control 2
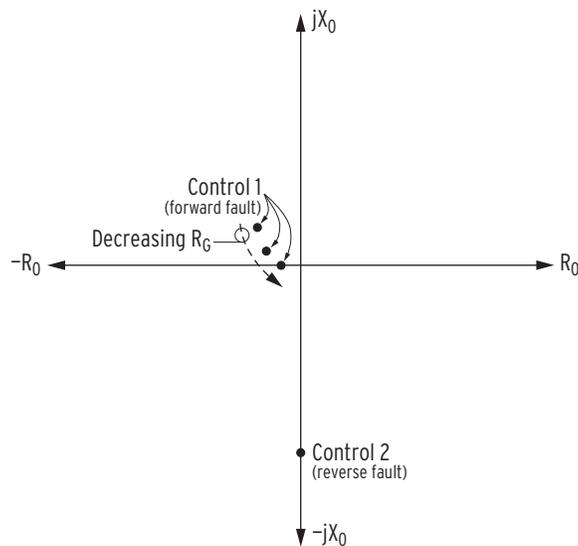
Figure 4.68 Zero-Sequence Impedance Plots for Ground Fault on Low-Impedance Grounded Distribution System

Assuming that all of the feeders in this distribution substation example have roughly the same amount of capacitance-creating network (e.g., underground cable), the following will apply:

➤ The Control 1 apparent zero-sequence impedance plot in *Figure 4.68* is representative of a ground fault in front of any control in the substation (forward fault).

➤ The Control 2 apparent zero-sequence impedance plot in *Figure 4.68* is representative of a ground fault behind any control in the substation (e.g., a ground fault on another parallel feeder; reverse fault).

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The forward/reverse impedance plots in *Figure 4.68* appear asymmetric, especially when compared to *Figure 4.63*(a) for a solidly grounded system with sources at each end. The Z0MTA setting in *Figure 4.63(a)* would (by inspection) be approximately 75 degrees.

Contrastingly, the Z0MTA setting for *Figure 4.68* has to allow the forward/reverse characteristic to fit in between the forward/reverse impedance plots. The forward impedance plot is the most critical to accommodate—one definitely wants to operate for a forward fault. This necessitates a Z0MTA setting of approximately -40 degrees (for the lowest value of neutral resistance R_G), as shown in *Figure 4.69* for this example. Necessary settings are as follows:

Global Settings

EGNDSW:= **Y**

Group Settings

E32:= **Y**

Z0F:= **−0.05**

Z0R:= **0.05**

Z0MTA:= **−40.00**

Other directional settings also have to be made (see *Figure 4.53* and *Figure 4.56*).

All these settings, zero-sequence voltage, and zero-sequence current converge on the zero-sequence voltage-polarized directional element in *Figure 4.56* (and its preceding enable logic in *Figure 4.53*) to produce the directional characteristic in *Figure 4.69*.

THE PATH FROM I_0 TO I_G
The I_G current value in Figure 4.53 and Figure 4.56 comes from the logic in Table 4.23. With Global setting EGNDSW := Y and channel IN wired in the factory-default residual connection with the phase current channels, I_G is always 3x the zero-sequence current I_0 of the feeders in the Figure 4.65 example. For a forward fault, $I_G = 3xI_{0(1)}$. For a reverse fault, $I_G = 3xI_{0(2)}$.
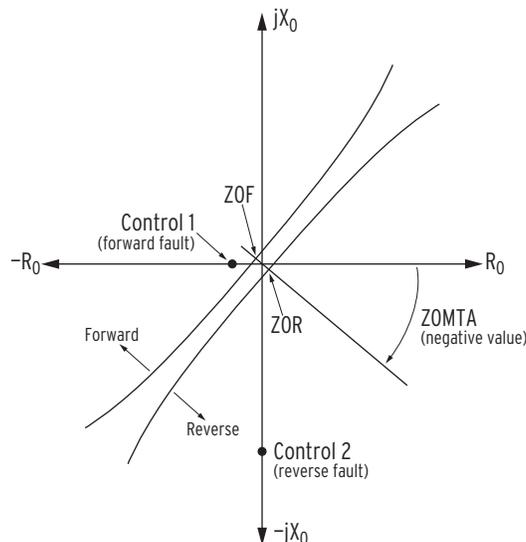
Figure 4.69   Z0MTA Setting Provides Forward/Reverse Ground Fault Discrimination in a Low-Impedance Grounded Distribution System

For more details on applying the Z0MTA setting on low-impedance grounded systems, refer to the following technical paper (available at selinc.com):

Selecting Directional Elements for Impedance-Grounded Distribution Systems by Ronald Lavorin (Southern California Edison), Daqing Hou, Héctor J. Altuve, Normann Fischer, and Fernando Calero (Schweitzer Engineering Laboratories, Inc.)

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In this paper, especially see pertinent discussion on modified 32V (zero-sequence voltage-polarized directional) elements in the following subsections:

➤ V. Modified Directional Elements for Low-Impedance-Grounded Systems with High Charging Capacitances

➤ VI. Analysis of a Practical Resistance-Grounded System

This subsection includes setting considerations involving the transformer bank (or grounding bank) zero-sequence impedance Z_{0T} and the neutral resistance R_G.

E32IV—SELOGIC Control Equation Enable

Refer to *Figure 4.53*.

SELOGIC control equation setting E32IV must be asserted to logical 1 to enable the zero-sequence voltage-polarized directional element for directional control of ground overcurrent elements.

Most often, this setting is set directly to logical 1:

E32IV := **1** (numeral 1)

For situations where zero-sequence source isolation can occur (e.g., by the opening of a circuit breaker) and result in possible mutual coupling problems for the zero-sequence voltage-polarized directional element, SELOGIC control equation setting E32IV should be deasserted to logical 0. In this example, this is accomplished by connecting a circuit breaker auxiliary contact from the identified circuit breaker to the SEL-651R-2:

E32IV := **IN106** (52a connected to optoisolated input **IN106**)

Almost any desired control can be set in SELOGIC control equation setting E32IV.

Overcurrent Directional Control Provided by Torque-Control Settings

The Relay Word bit outputs of *Figure 4.57* and *Figure 4.61* are used in the torque-control settings to provide directional control for overcurrent elements. These Relay Word bit outputs are listed in the middle column of *Table 4.25*. Each line in *Table 4.25* (left to right) lists the torque-control setting, the suggested Relay Word bits to provide directional control, and the overcurrent element controlled by the torque-control setting. The torque-control setting (left column) can be found in the same figure reference as the corresponding overcurrent element (right column).

Table 4.25 Providing Directional Control for Overcurrent Elements With Torque-Control Settings (Sheet 1 of 2)

Torque-Control Settings	Relay Word Bits Providing Directional Control (Figure Reference)	Controlled Overcurrent Elements (Figure Reference)
50P1TC–50P4TC	32PF/32PR (*Figure 4.61*)	50P1T–50P4T (*Figure 4.3*)
50A1TC–50A4TC	32PF/32PR (*Figure 4.61*)	50A1T–50A4T (*Figure 4.4*)
50B1TC–50B4TC	32PF/32PR (*Figure 4.61*)	50B1T–50B4T (*Figure 4.5*)

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Table 4.25 Providing Directional Control for Overcurrent Elements With Torque-Control Settings (Sheet 2 of 2)

Torque-Control Settings	Relay Word Bits Providing Directional Control (Figure Reference)	Controlled Overcurrent Elements (Figure Reference)
50C1TC–50C4TC	32PF/32PR (*Figure 4.61*)	50C1T–50C4T (*Figure 4.6*)
50N1TC–50N4TC		50N1T–50N4T (*Figure 4.10*)
50G1TC–50G4TC	32GF/32GR (*Figure 4.57*)	50G1T–50G4T (*Figure 4.12*)
50Q1TC–50Q4TC	32QF/32QR (*Figure 4.61*)	50Q1T–50Q4T (*Figure 4.14*)
51PTC	32PF/32PR (*Figure 4.61*)	51PT (*Figure 4.16*)
51ATC	32PF/32PR (*Figure 4.61*)	51AT (*Figure 4.17*)
51BTC	32PF/32PR (*Figure 4.61*)	51BT (*Figure 4.18*)
51CTC	32PF/32PR (*Figure 4.61*)	51CT (*Figure 4.19*)
51N1TC		51N1T (*Figure 4.20*)
51N2TC		51N2T (*Figure 4.21*)
51G1TC	32GF/32GR (*Figure 4.57*)	51G1T (*Figure 4.22*)
51G2TC	32GF/32GR (*Figure 4.57*)	51G2T (*Figure 4.23*)
51QTC	32QF/32QR (*Figure 4.61*)	51QT (*Figure 4.24*)

For example, to provide forward directional control for time-overcurrent element 51G1T, make the following torque-control setting:

51G1TC := **32GF**

The factory-default for this torque-control setting is as follows:

51G1TC := **LT01**   (see *Figure 9.31*)

Latch output LT01 (see *Figure 7.6*) is set to enable/disable ground overcurrent tripping (see setting SET01 and RST01 in *Figure 9.32*), via the **GROUND ENABLED** operator control pushbutton (see *Table 11.9*). To incorporate this factory-default front-panel operator control capability with forward directional control, make the following combined setting:

51G1TC := **LT01 AND 32GF**

Channel IN Overcurrent Elements

Note that no suggested Relay Word bits for directional control are given in the corresponding middle column in *Table 4.25* for channel IN overcurrent elements 50N1T–50N4T, 51N1T, and 51N2T.

As explained in the text accompanying *Figure 4.10* and *Figure 4.20*, these channel IN overcurrent elements only become available if Global setting EGNDSW := N. *Table 4.23* shows that channel IN current is treated as a totally separate current source for this scenario (separate from internal residually derived ground current $I_G = 3I_0 = I_A + I_B + I_C$). Thus, it is unlikely that these channel IN overcurrent elements would be used in a directional scheme, where ground directionality would come from currents I_G (ground/zero-sequence) and I_2 (negative-sequence) derived from currents I_A, I_B, and I_C (see *Figure 4.55* and *Figure 4.56*).

Instantaneous Overcurrent Elements

The 50_ _TC torque-control settings in *Table 4.25* do not control the corresponding instantaneous elements. For example, at the top of *Figure 4.12*, torque-control setting 50G1TC controls the ground definite-time overcurrent element 50G1T, but not ground instantaneous overcurrent element 50G1. To make an instantaneous overcurrent element directional, supervise it with a directional element in SELOGIC control equations (e.g., 50G1 AND 32GR).

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Single-Phase Tripping

If a recloser is set for single-phase or three-phase tripping (Group setting ESPB := Y; see *Figure 5.1*), the ground directional elements (*Figure 4.55* and *Figure 4.56*) and negative-sequence directional element (*Figure 4.59*) automatically turn off when one or two phases are tripped. This is because of the single-pole open logic (*Figure 5.5*) and Relay Word bit output SPO that supervises the ground directional element enables 32QGE and 32VE (*Figure 4.52* and *Figure 4.53*) and the negative-sequence directional element enable 32QE (*Figure 4.52*).

The phase directional element (*Figure 4.60*) is not supervised by the Relay Word bit output SPO. But once one or two phases are tripped, the phase directional element effectively shuts down/turns off—it cannot make a three-phase decision (all three phases have to agree for a directional decision).

Setting Negative-Sequence Overcurrent Elements

Setting Negative-Sequence Definite-Time Overcurrent Elements

Negative-sequence instantaneous overcurrent elements 50Q1–50Q6 should not be set to trip directly. This is because negative-sequence current can transiently appear when a circuit breaker is closed and balanced load current suddenly appears.

To avoid tripping for this transient condition, use negative-sequence definite-time overcurrent elements 50Q1T–50Q4T with at least 1.5 cycles of time delay (transient condition lasts less than 1.5 cycles). For example, make the following time delay setting for negative-sequence definite-time overcurrent element 50Q1T:

    50Q1D := **1.50**

Refer to *Figure 4.14* and *Figure 4.15* for more information on negative-sequence instantaneous and definite-time overcurrent elements.

Negative-sequence instantaneous overcurrent elements 50Q5 and 50Q6 do not have associated timers (compare *Figure 4.15* to *Figure 4.14*). If 50Q5 or 50Q6 need to be used for tripping, run them through SELOGIC control equation variable timers (see *Figure 7.3*) and use the outputs of the timers for tripping.

Continue reading in *Coordinating Negative-Sequence Overcurrent Elements on page 4.106* for guidelines on coordinating negative-sequence definite-time overcurrent elements and a following coordination example. The coordination example uses time-overcurrent elements, but the same principles can be applied to definite-time overcurrent elements.

Setting Negative-Sequence Time-Overcurrent Elements

Negative-sequence time-overcurrent element 51QT should not be set to trip directly when it is set with low time-dial settings 51QJTD or 51QKTD, which result in curve times below 3 cycles (see curves in *Figure 9.1–Figure 9.20*). This is because negative-sequence current can transiently appear when a circuit breaker is closed and balanced load current suddenly appears. Refer to *Figure 4.24* for more information on negative-sequence time-overcurrent element 51QT.

To avoid having negative-sequence time-overcurrent element 51QT with such low time-dial settings trip for this transient negative-sequence current condition, make corresponding minimum response time setting:

    51Q_MR := **1.50 cycles** (minimum response time; transient condition lasts less than 1.5 cycles) (replace "_" with J or K).

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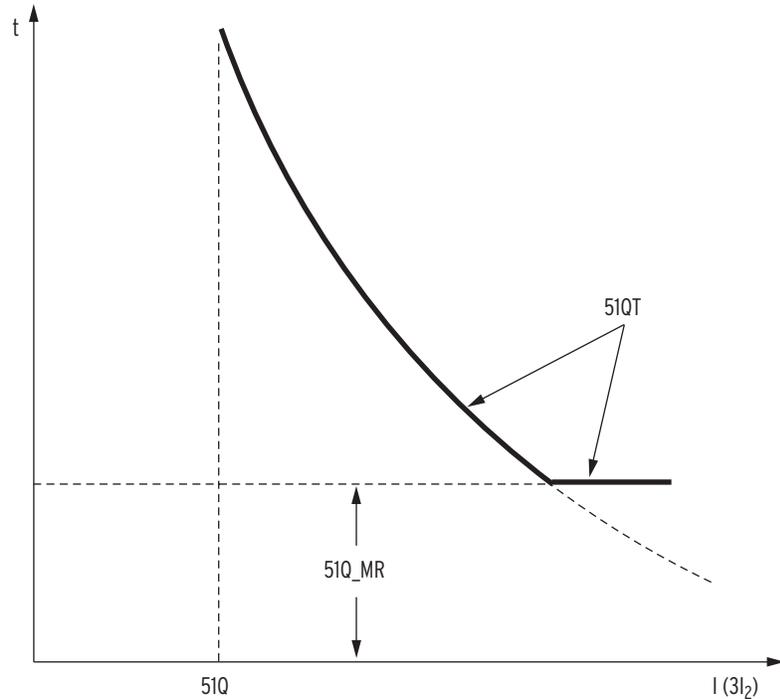
Figure 4.70   Minimum Response Time Added to a Negative-Sequence Time-Overcurrent Element 51QT

Coordinating Negative-Sequence Overcurrent Elements

NOTE: The overcurrent element labels in the example are not the same as the labels of the corresponding SEL-651R-2 overcurrent elements.

The following coordination guidelines and example assume that the negative-sequence overcurrent elements operate on $3I_2$ magnitude negative-sequence current and that the power system is radial. The negative-sequence overcurrent elements in the SEL-651R-2 operate on $3I_2$ magnitude negative-sequence current.

The coordination example is a generic example that can be used with any relay containing negative-sequence overcurrent elements that operate on $3I_2$ magnitude negative-sequence current. The SEL-651R-2 can be inserted as the feeder relay in this example.

Coordination Guidelines

1. Start with the farthest downstream negative-sequence overcurrent element (e.g., distribution feeder relay in a substation).

2. Identify the phase overcurrent device (e.g., line recloser, fuse) downstream from the negative-sequence overcurrent element that is of greatest concern for coordination. This is usually the phase overcurrent device with the longest clearing time.

3. Consider the negative-sequence overcurrent element as an "equivalent" phase overcurrent element. Derive pickup, time dial (lever), curve type, or time-delay settings for this equivalent element to coordinate with the downstream phase overcurrent device, as any phase coordination would be performed. Load considerations can be disregarded when deriving the equivalent phase overcurrent element settings.

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4. Multiply the equivalent phase overcurrent element pickup setting by $\sqrt{3}$ to convert it to the negative-sequence overcurrent element pickup setting in terms of $3I_2$ current.

$$\binom{\text{Negative-sequence overcurrent}}{\text{element pickup}} = \sqrt{3} \cdot \binom{\text{equivalent phase overcurrent}}{\text{element pickup}}$$

Any time dial (lever), curve type, or time delay calculated for the equivalent phase overcurrent element is also used for the negative-sequence overcurrent element with no conversion factor applied.

5. Set the next upstream negative-sequence overcurrent element to coordinate with the first downstream negative-sequence overcurrent element and so on. Again, coordination is not influenced by load considerations.

Coordination Example

In *Figure 4.71*, the phase and negative-sequence overcurrent elements of the feeder relay (51F and 51QF, respectively) must coordinate with the phase overcurrent element of the line recloser (51R).
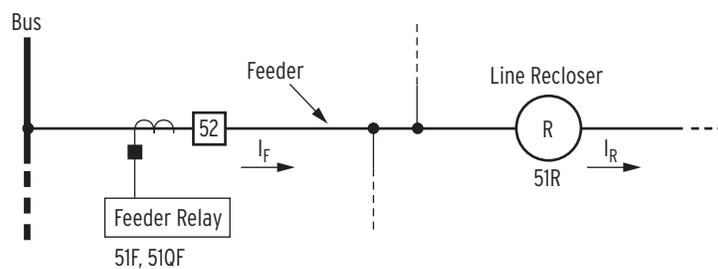
I_F = Maximum load current through feeder relay = 450 A
I_R = Maximum load current through line recloser = 150 A
51F = Feeder relay phase time-overcurrent element
51QF = Feeder relay negative-sequence time-overcurrent element
51R = Line recloser phase time-overcurrent element (phase "slow curve")

Figure 4.71   Distribution Feeder Protective Devices

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Traditional Phase Coordination
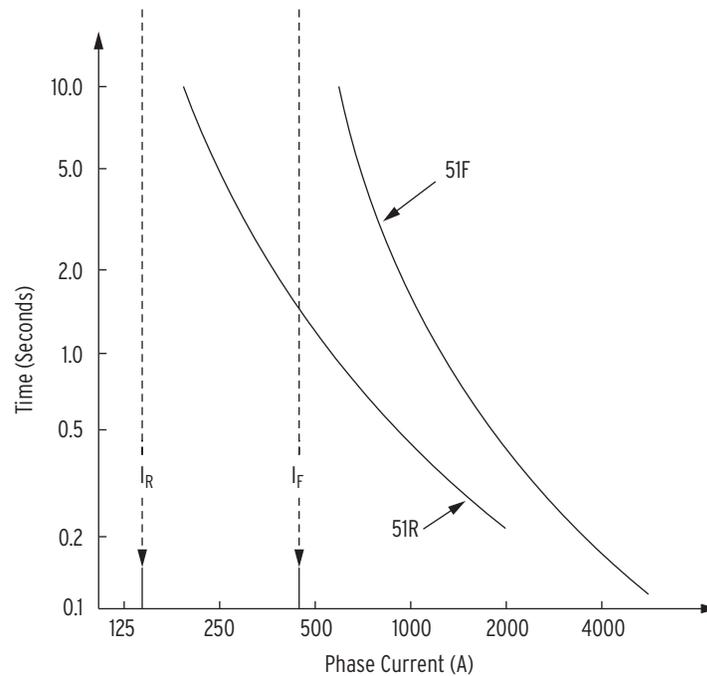
51F: pickup = 600 A (above max. feeder load, I_F)
51R: pickup = 200 A (above max. line recloser load, I_R)

Figure 4.72   Traditional Phase Coordination

Figure 4.72 shows traditional phase overcurrent element coordination between the feeder relay and line recloser phase overcurrent elements. Phase overcurrent elements must accommodate load and cold load pickup current. The 450 A maximum feeder load current limits the sensitivity of the feeder phase overcurrent element, 51F, to a pickup of 600 A. The feeder relay cannot back up the line recloser for phase faults below 600 A.

Apply the Feeder Relay Negative-Sequence Overcurrent Element (Guidelines 1 to 3)

Applying negative-sequence overcurrent element coordination Guidelines 1 to 3 results in the feeder relay equivalent phase overcurrent element (51EP) in *Figure 4.73*. Curve for 51F is shown for comparison only.

Considerable improvement in sensitivity and speed of operation for phase-to-phase faults is achieved with the 51EP element. The 51EP element pickup of 300 A has twice the sensitivity of the 51F element pickup of 600 A. The 51EP element speed of operation for phase-to-phase faults below about 2000 A is faster than that for the 51F element.

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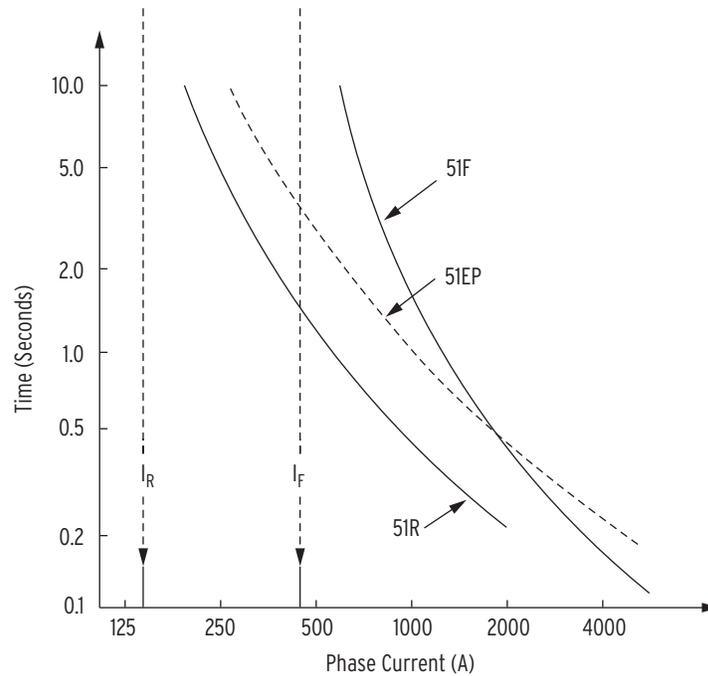
51EP: pickup = 300 A (below max. feeder load, I_F)

Figure 4.73   Phase-to-Phase Fault Coordination

Convert Equivalent Phase Overcurrent Element Settings to Negative-Sequence Overcurrent Element Settings (Guideline 4)

The equivalent phase overcurrent element (51EP element in *Figure 4.73*) converts to true negative-sequence overcurrent element settings (51QF in *Figure 4.74*) by applying the equation given in Guideline 4. The time dial (lever) and curve type of the element remain the same (if the element is a definite-time element, the time delay remains the same).

Having achieved coordination between the feeder relay negative-sequence overcurrent element (51QF) and the downstream line recloser phase overcurrent element (51R) for phase-to-phase faults, coordination between the two devices for other fault types is also achieved.

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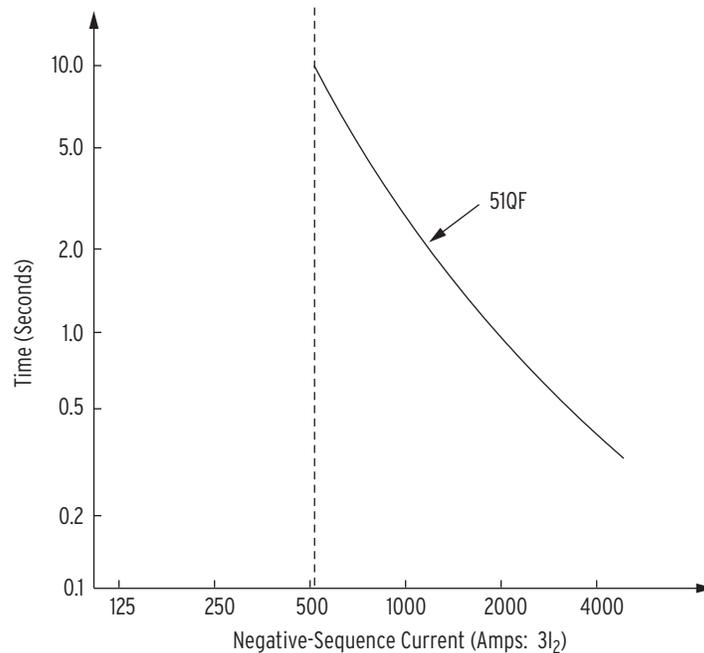
Figure 4.74   Negative-Sequence Overcurrent Element Derived From Equivalent Phase Overcurrent Element 51EP

Negative-Sequence Overcurrent Element Applied at a Distribution Bus (Guideline 5)

The preceding example was for a distribution feeder. A negative-sequence overcurrent element protecting a distribution bus provides an even more dramatic improvement in phase-to-phase fault sensitivity.

The distribution bus phase overcurrent element pickup must be set above the combined load of all the feeders on the bus, plus any emergency load conditions. The bus phase overcurrent element pickup is often set at least four times greater than the pickup of the feeder phase overcurrent element it backs up. Thus, sensitivity to both bus and feeder phase faults is greatly reduced. Feeder relay backup by the bus relay is limited.

Negative-sequence overcurrent elements at the distribution bus can be set significantly below distribution bus load levels and provide dramatically increased sensitivity to phase-to-phase faults. It is coordinated with the distribution feeder phase or negative-sequence overcurrent elements and provides more-sensitive and faster phase-to-phase fault backup.

Ground Coordination Concerns

If the downstream protective device includes ground overcurrent elements, in addition to phase overcurrent elements, there should be no need to check the coordination between the ground overcurrent elements and the upstream negative-sequence overcurrent elements. The downstream phase overcurrent element, whether it operates faster or slower than its complementary ground overcurrent element, will operate faster than the upstream negative-sequence overcurrent element for all faults, including those that involve ground.

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Other Negative-Sequence Overcurrent Element References

The following IEEE paper is the source of the coordination guidelines and example given in this appendix. The paper also includes analyses of system unbalances and faults and the negative-sequence current generated by such conditions:

> A. F. Elneweihi, E. O. Schweitzer, M. W. Feltis, *Negative-Sequence Overcurrent Element Application and Coordination in Distribution Protection*, IEEE Transactions on Power Delivery, Volume 8, Number 3, July 1993, pp. 915-924.

The following conference paper gives many good application examples for negative-sequence overcurrent elements. The focus is on the transmission system, where negative-sequence overcurrent elements provide better sensitivity than zero-sequence overcurrent elements in detecting some single-line-to-ground faults:

> A. F. Elneweihi, *Useful Applications for Negative-Sequence Overcurrent Relaying*, 22nd Annual Western Protective Relay Conference, Spokane, Washington, October 24-26, 1995.

High-Impedance Fault Detection (Arc Sense Technology)

NOTE: The SEL-651R-2 uses nonharmonic content in phase currents to detect arcing during high impedance faults. SEL-451 and SEL-751 uses both nonharmonic and odd-harmonic content to detect arcing.

NOTE: Detecting high-impedance faults has challenged utilities and researchers for years, especially in situations where a fault occurs on asphalt or dry sand or generates little or virtually no fault current. As is commonly known, not all HIFs are detectable. Detecting HIFs potentially reduces the risks associated with these faults. The SEL HIF detection method increases the likelihood that an HIF will be detected.

High-impedance fault detection (Arc Sense technology) is available in select SEL-651R-2 models. The part number indicates whether the relay supports high-impedance fault detection.

High-impedance faults (HIF) are short-circuit faults with fault currents smaller than what a traditional overcurrent protective relay can detect. The main causes of HIFs are tree branches touching a phase conductor, failing or dirty insulators that cause flashovers between a phase conductor and the ground or downed conductors. Almost all HIFs involve the ground directly or indirectly.

Staged downed-conductor fault tests in North America indicate that downed-conductor HIFs generate quite small fault currents. The HIF current of multigrounded systems depends highly on the surface types upon which a conductor falls, and the fault current varies from zero to less than 100 A.

The high-impedance fault (HIF) detection method shown in *Figure 4.75* incorporates the following key elements:

> ➤ An informative quantity that reveals HIF signatures as much as possible without being affected by loads and other system operation conditions.

> ➤ A running average of the quantity that provides a stable prefault reference.

> ➤ An adaptive tuning feature that learns and tunes out feeder ambient noise conditions.

> ➤ Decision logic to differentiate an HIF condition from other system conditions such as switching operations and noisy loads.

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High-Impedance Fault Detection (Arc Sense Technology)

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The HIF detection element derives a Sum of Difference Current (SDI) that represents the total nonharmonic contents of the phase currents to detect a HIF signature. An averaging filter generates a stable reference of SDI and adapts to the ambient conditions of feeder loads. In turn, an adapted detection threshold is established based on the trends of the measured SDI and decision logic is used to separate normal trending from the existence of a HIF on the distribution system. The SEL Technical Paper *Detection of High-Impedance Faults in Power Distribution Systems* by Daqing Hou, details additional information about this HIF detection method.

(a) Block Diagram of HIF Detection Non-Harmonic
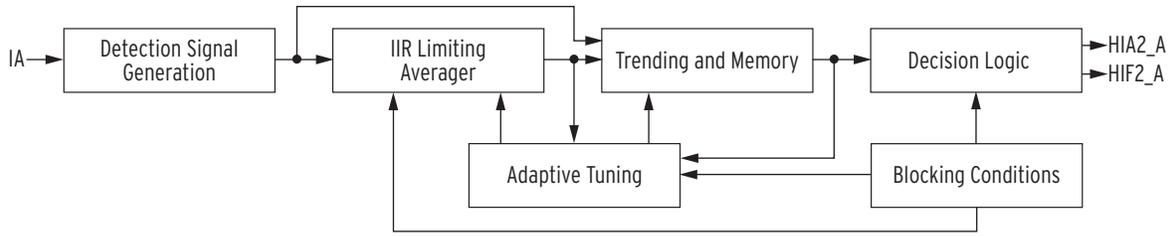
(b) Detection Signal Generation SDI Non-Harmonic
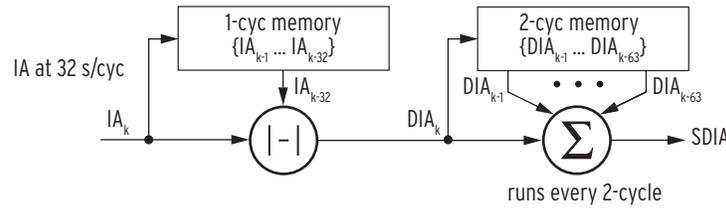
Note: A-phase logic is shown above; B and C phases are similar.

Figure 4.75   Block Diagram of HIF Detection

HIF Detection Settings

Table 4.26 lists the relay settings corresponding to high-impedance fault detection.

Table 4.26   High-Impedance Fault (HIF) Detection Settings

Label	Prompt	Default Value
EHIF	EHIF Enable High Impedance Fault Detection (Y,N,T)	N
HIFMODE	HIF Detection Sensitivity (SELOGIC Equation)	NA
HIFFRZ	Freeze HIF Detection Algorithm (SELOGIC Equation)	TRIP3P OR TRIPA OR TRIPB OR TRIPC
HIFITUNE	Begin Initial 24-Hour HIF Tuning Process (SELOGIC Equation)	NA
HIFLER	Length of HIF Event Report	10 minutes
HIFER	HIF Event Report Ext. Trigger (SELOGIC Equation)	NA

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High-impedance fault detection is enabled by Group setting EHIF := Y or T. When EHIF is set to Y and current above the threshold of $0.05 \cdot I_{NOM}$ is applied to the relay, the detection algorithm calculates a running average of the sum of difference current to provide a stable prefault reference. This process is referred to as the initial tuning mode. When the relay is in the initial tuning mode, Relay Word bits ITUNE_A, ITUNE_B, and/or ITUNE_C assert if current is detected on that particular phase. During the initial tuning process, the HIF alarm and fault bits are disabled. The initial tuning process takes 24 hours but is interrupted by a change in the EHIF setting, a change in the NFREQ setting, a change in the VSELECT setting, a loss of load current, or a relay trip condition. Once interrupted, the initial tuning process re-starts when load current is detected.

The initial tuning process can be forced to re-start with either the **INI HIF** command or by asserting the programmable SELOGIC equation HIFITUNE. The **INI HIF** command or HIFITUNE equation are also used to force initial tuning when the line configuration the relay is monitoring changes (see *Example 4.1– Example 4.5* for details). See *INI HIF Command (Only Available In Relays That Support Arc Sense Technology) on page 10.55* for more information on the **INI HIF** command.

After the initial tuning process, the relay enters the normal tuning mode where it continues to tune to the present power system conditions. When the relay is in normal tuning mode, Relay Word bits NTUNE_A, NTUNE_B, and/or NTUNE_C are asserted if current is detected on that particular phase. If the relay does not detect load current while in normal tuning mode, the relay stops tuning and retains the long-term reference value for four hours, this prevents the relay from re-tuning following a short system disturbance. The programmable SELOGIC control equation HIFFRZ can be used to retain the learned reference quantities indefinitely (see *Example 4.1– Example 4.5* for details). If a line is de-energized for more than four hours and the SELOGIC equation HIFFRZ is not asserted, the relay re-starts the initial tuning process upon the re-energization of the line.

When EHIF is set to T (Test), the detection algorithm bypasses the 24-hour tuning process and is immediately available for testing purposes. The relay must be tracking frequency (Relay Word bit FREQOK = 1) in order for the high-impedance fault detection algorithm to work; if the relay is not tracking frequency (Relay Word bit FREQOK = 0) the algorithm is disabled.

The SEL-651R-2 is often applied in systems where reconfiguration occurs. For example, SEL Distribution Network Automation (DNA) solutions use the capabilities of the SEL-651R-2 to reconfigure networks during abnormal power system conditions to limit the number of people that are impacted by system faults. System reconfiguration can impact the effectiveness of the HIF algorithm. The HIF algorithm adapts to minor changes in load, but large changes could potentially cause the long-term reference quantity to not reflect the existing power system conditions. To prevent system reconfiguration from adversely affecting the performance of the HIF algorithm, SEL has introduced the HIFITUNE and HIFFRZ programmable SELOGIC control equations. The following use cases describe examples of using the equations.

EXAMPLE 4.1   Use Case #1 (Loss of load current and line configuration remains the same):

For this example, assume that the following conditions occur:

1.   The HIF algorithm is operating in normal tuning mode.
2.   The energized line goes dead.

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3. The line configuration does not change.

4. The line is re-energized.

In this case, the user can assert the SELOGIC control equation, HIFFRZ, which will retain the long-term HIF reference value. When the line is re-energized, HIFFRZ should be deasserted and the HIF algorithm will return to normal tuning mode.

EXAMPLE 4.2   Use Case #2 (Loss of load current for less than 4 hours and line configuration permanently changes):

For this example, assume that the following conditions occur:

1. The HIF algorithm is operating in normal tuning mode.

2. The energized line goes dead.

3. The line configuration permanently changes.

4. The line is re-energized in less than 4 hours.

In this case, the user will more than likely have to take action to ensure the HIF algorithm is not adversely impacted. The line being monitored by the SEL-651R-2 has changed; and therefore, the load characteristics of the system have also changed. The user should consider forcing the HIF algorithm into initial tuning mode by issuing the INI HIF command or asserting the SELOGIC control equation, HIFITUNE. The user can manually assert the HIFITUNE equation or use a distribution automation controller to assert and deassert the HIFITUNE equation. Forcing tuning prevents the algorithm from using the "old" reference value on the "new" line configuration.

EXAMPLE 4.3   Use Case #3 (Loss of load current for more than 4 hours and line configuration permanently changes):

For this example, assume that the following conditions occur:

1. The HIF algorithm is operating in normal tuning mode.

2. The energized line goes dead.

3. The line configuration permanently changes.

4. The line is re-energized more than 4 hours after going dead.

In this case, the user does not have to take any special action to ensure that the HIF algorithm is not impacted by the disturbance. The relay will immediately enter initial tuning mode when the line is re-energized.

EXAMPLE 4.4   Use Case #4 (Load current is not lost and line configuration temporarily changes):

For this example, assume that the following conditions occur:

1. The HIF algorithm is operating in normal tuning mode.

2. The line remains energized.

3. The line configuration the relay is monitoring temporarily changes (e.g., significant load is picked-up or dropped).

In this case, the user should assert the SELOGIC control equation, HIFFRZ, until the original line configuration is restored. Asserting HIFFRZ disables the HIF algorithm. Once the original line configuration is restored, HIFFRZ should be deasserted and the HIF algorithm will return to normal tuning mode.

EXAMPLE 4.5   Use Case #5 (Load current is not lost and line configuration permanently changes):

For this example, assume that the following conditions occur:

1. The HIF algorithm is operating in normal tuning mode.

2. The line remains energized.

3. The line configuration the relay is monitoring permanently changes (e.g., significant load is picked-up or dropped).

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In this case, the line configuration being monitored by the SEL-651R-2 has changed; and therefore, the load characteristics of the system have also probably changed. The user should consider forcing the HIF algorithm into initial tuning mode by issuing the INI HIF command or asserting the SELOGIC control equation, HIFITUNE. Forcing tuning prevents the algorithm from using the "old" reference value on the "new" line configuration.

High-impedance fault detection sensitivity is controlled by group SELOGIC control equation setting HIFMODE. Assertion of this logic equation sets Relay Word bit HIFMODE and increases the sensitivity of the detection algorithm.

EXAMPLE 4.6   HIFMODE Programming and Operation

As detailed above, assertion of the HIFMODE SELOGIC control equation controls the sensitivity of the high-impedance fault detection algorithm. Field experience may suggest that downed conductor events that lead to high-impedance faults might occur more frequently during periods of storm activity. Furthermore, conductor configuration could make it likely that a downed conductor might initially create a high-current fault by making temporary contact with another conductor. This fault would be detected and cleared; disappearing upon a successful auto-reclosure. The downed conductor would then be creating a high-impedance fault. It is during this time that it would be desirable to increase the sensitivity of the high-impedance fault detection algorithm. In this example a successful reclosure triggers a timer input. The dropout period of the timer is set to the period of time that is desired for increased detection sensitivity.

Enter the following Group settings:

EHIF := Y

HIFMODE := SV16T AND 52A3P #HIFMODE SELOGIC control equation variable follows the SELOGIC timer output.

Enter the following Logic settings:

SV16PU := 0.0 # Pickup set to 0.0 cycles

SV16DO := 108000.0 # Dropout set to 30.0 minutes on a 60 Hz system

SV16 := R_TRIG 79CY3P # Reclosing relay is in reclose cycle state

When the recloser enters the reclose cycle state, 79CY3P asserts the output for SELOGIC variable 16. The SV16T stays asserted for the duration of the dropout setting, which is 30 minutes in this example. During this 30 minutes, the SV16T assertion maintains the assertion of HIFMODE, assuring a window of time for increased sensitivity of the HIF detection algorithm.

Group SELOGIC control equation setting HIFER allows for the automatic triggering of HIF detection event reports. Assertion of HIFER asserts Relay Word bit HIFREC and triggers an event report.

HIF Detection Logical Outputs

The SEL-651R-2 indicates HIF detection through the Relay Word Bit outputs detailed in *Table 4.27*. Relay word bits can be used in custom logic programming to indicate high-impedance fault detection activity.

Table 4.27   HIF Relay Word Bits (Sheet 1 of 2)

HIF Activity	Relay Word Bits
HIF SDI (nonharmonic) ALARM	HIA2_A, HIA2_B, HIA2_C
HIF SDI (nonharmonic) FAULT	HIF2_A, HIF2_B, HIF2_C
Freeze and Retain the learned HIF quantities during a system disturbance	FRZCLRA, FRZCLRB, FRZCLRC, HIFFRZ

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Table 4.27 HIF Relay Word Bits (Sheet 2 of 2)

HIF Activity	Relay Word Bits
Current Disturbance	DIA_DIS, DIB_DIS, DIC_DIS
Voltage Disturbance	DVA_DIS, DVB_DIS, DVC_DIS
Disable HIF Decision Logic	DL2CLRA, DL2CLRB, DL2CLRC
Initial Tuning in Progress	ITUNE_A, ITUNE_B, ITUNE_C
Initiate Tuning Process	INI_HIF, HIFITUNE
Normal Tuning in Progress	NTUNE_A, NTUNE_B, NTUNE_C
Increase the HIF Tuning Threshold	DUPA, DUPB, DUPC
Decrease the HIF Tuning Threshold	DDNA, DDNB, DDNC
Load Reduction Detected	LRA, LRB, LRC, LR3
HIF Externally Triggered Event	HIFER
HIF Detection Mode Sensitivity	HIFMODE
HIF Event Report is being collected	HIFREC

HIF Detection Event Reports and Histories

The SEL-651R-2 stores HIF detection information as oscillography in binary COMTRADE format, compressed events, event summaries, and histories. See *HIF Event Summary on page 12.48*, *High-Impedance Fault Compressed Event Report on page 12.52*, *High-Impedance Fault Metering on page 8.23*, *LOG HIF Command (Only Available In Relays That Support Arc Sense Technology) on page 10.55*, and *Viewing the HIF Event History on page 12.51* for more information.

HIF Coordination

Coordination of high-impedance fault detection is possible when multiple SEL-651R-2 recloser controls and/or substation relays that contain high-impedance fault detection, like the SEL-451, are applied on the same line. Coordination can minimize the number of impacted customers and increase efficiency of fault location.

50G High-Impedance (HIZ) Fault Detection

APPLYING 50G HIZ
See 50G HIZ Application Considerations.

50G high-impedance (HIZ) fault detection is available in select SEL-651R-2 models. The part number indicates whether the relay supports high-impedance fault detection.

An additional and wholly separate method of detecting high-impedance fault activity is the ground overcurrent high-impedance (50G HIZ) fault detection method. The 50G HIZ detection method counts the number of times an instantaneous ground overcurrent element (50G) asserts and deasserts at a very low pickup threshold within a settable period of time. This activity could indicate the presence of a small magnitude arcing fault on the system. Some hysteresis is built into the 50G element to minimize element chatter resulting from nonfault activity. The SEL-651R-2 stores 50G HIZ detection information in a report that is obtained with the **HIZ** command. See *Figure 4.76* for a sample HIZ report.

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```
FEEDER 1                          Date: 07/19/2012  Time: 16:16:57.461
STATION A                         Time Source: external

#    Beginning Date/Time          Ending Date/Time            Counts

1    06/07/2012  14:56:29.537     06/07/2012  14:56:39.166      18
2    06/06/2012  10:23:12.537     06/06/2012  10:23:17.166       9
```

Figure 4.76 Sample HIZ Report

50G HIZ Detection Settings

Table 4.28 lists the relay settings corresponding to ground overcurrent high-impedance fault detection.

Table 4.28 50G High-Z (HIZ) Fault Detection Settings

Label	Prompt	Default Value
50GHIZP	50G HIZ Overcurrent Pickup (see *50GHIZP Range*)	OFF
NPUD0	50G HIZ Element Pickup/Dropout Counts (1–1000)	10
TPUD0	NPUDO Time Window (0.01–20 seconds)	2.00
NHIZ	HIZ Counts [1 HIZ count = NPUDO counts] (1–1000)	100
THIZ	NHIZ Time Window (1–200 seconds)	60.00
NHIZR	HIZ Counts Reporting Threshold (1–1000)	95
HIZRST	HIZ Alarm Reset (SELOGIC Equation)	NA

50GHIZP Range

Setting Range:

> 0.005–20.000 A secondary in 0.001 A steps
> (on channel IN base*, when Global setting EGNDSW := Y and Group setting CTR = CTRN)

> 0.005–[20 • (CTR/CTRN)] A secondary in 0.001 A steps
> (on channel IN base, when Global setting EGNDSW := Y and Group setting CTR ≠ CTRN)

> 0.010–20.000 A secondary in 0.001 A steps
> (on IA, IB, IC base, when Global setting EGNDSW := N)

> * **Note:** In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2.

Ground overcurrent high-impedance fault detection is enabled by Group setting 50GHIZP. When 50GHIZP is set to any value other than OFF, ground instantaneous overcurrent element 50GHIZ is enabled to initiate 50G HIZ fault detection. *Figure 4.77* shows the operating logic for element 50GHIZ.
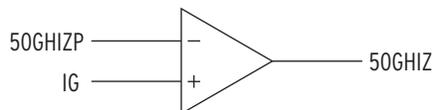
Figure 4.77 Ground Instantaneous Overcurrent Element 50GHIZ

When the 50G HIZ logic is initializing, the Relay Word bit HIZ170 is asserted. Relay Word bit HIZ171 will assert when the 50G HIZ logic begins to process. The assertion of 50GHIZ (HIZ172 asserts) and deassertion of 50GHIZ (HIZ173 asserts) causes counter CPUDO to increment. Group setting NPUDO establishes a threshold that counter CPUDO must meet in order for

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50G HIZ fault detection to continue. Group setting TPUDO establishes a time window within which counter CPUDO must meet the NPUDO threshold. If CPUDO reaches NPUDO within TPUDO, counter CHIZ is then incremented (HIZ174 asserts). If it does not, counter CPUDO is reset (HIZ180 asserts) and the logic starts over.

Group setting NHIZ establishes a threshold that counter CHIZ must meet in order for 50G HIZ fault detection to continue. Group setting THIZ establishes a time window within which counter CHIZ must meet the NHIZ threshold. If CHIZ reaches NHIZ within THIZ, Relay Word bit 50GHIZA is asserted (HIZ175 asserts) and latched; group SELOGIC setting HIZRST resets 50GHIZA. Group setting NHIZR establishes a separate threshold at which HIZ report entries are generated. Refer to the following section for an example of how these settings can be utilized to for 50G HIZ fault detection.

NOTE: Use the HIZxxx Relay Word bits during testing to indicate the progression of the 50G HIZ logic. SEL does not recommended using HIZxxx bits in the SER or in SELOGIC during normal operation.

Table 4.29 50G HIZ Relay Word Bits

Relay Word bit	Description of Relay Word bits
HIZ170	50G HIZ logic is in its initialization state, all other 50G HIZ Relay Word bits are deasserted, all counters (CPUDO and CHIZ) are forced to zero, and all timers (TPUDO and THIZ) are forced to zero. The HIZ logic returns to this state if a trip condition is detected.
HIZ171	The HIZ logic is enabled and waiting for 50GHIZ Relay Word bit to assert.
HIZ172	50GHIZ has asserted and the HIZ logic is waiting for 50GHIZ to deassert.
HIZ173	50GHIZ element has deasserted, CPUDO counter increments one count, the TPUDO timer starts (HIZ181), and the HIZ logic is waiting for 50GHIZ to assert again (HIZ171).
HIZ174	The CPUDO count is equal to the NPUDO setting, CPUDO gets reset to zero (HIZ180), CHIZ increments one count, and the HIZ logic returns to waiting for 50GHIZ to assert again (HIZ171).
HIZ175	The CHIZ count is equal to the NHIZ setting, the high-impedance alarm bit, 50GHIZA, latches in, and the HIZ logic enters the initialization state (HIZ170).
HIZ180	CPUDO counter is set to zero (initialization state for CPUDO counter)
HIZ181	The HIZ logic is waiting for CPUDO to equal NPUDO (HIZ174) or for TPUDO to timeout. When one of the conditions is met, CPUDO is reset to zero (HIZ180) and either CHIZ increments (HIZ174) or the HIZ logic re-starts (HIZ171).
HIZ190	CHIZ counter is set to zero (initialization state for CHIZ counter).
HIZ191	The HIZ logic is waiting for CHIZ to equal NHIZ (HIZ175) or for THIZ to timeout. When one of the conditions is met, HIZ192 asserts, CHIZ is reset to zero (HIZ190) and either 50GHIZA (HIZ175) asserts or the HIZ logic re-starts (HIZ171).
HIZ192	Intermediate state before forcing the CHIZ counter back to zero (HIZ190).

50G HIZ Detection Logic Example

Figure 4.78 and *Figure 4.79* show how the example HIZ report entries in *Figure 4.76* are generated. Compared to the settings ranges given in *Table 4.28*, the following example settings NHIZR = 6 and NHIZ = 18 appear especially small and are for illustrative purposes only.

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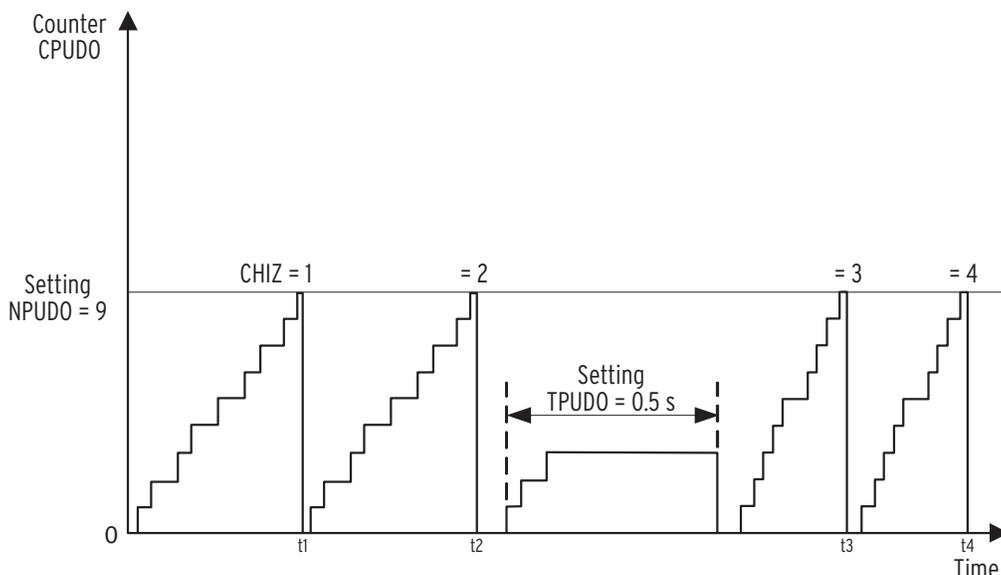
Figure 4.78   Counter CPUDO for Assertion/Deassertion of Ground Fault Overcurrent Element 50GHIZ

Figure 4.78 shows counter CPUDO incrementing from 0 to NPUDO = 9. This has to be done within time TPUDO (0.5 seconds in this example), or counter CPUDO is reset (HIZ180 asserts). Notice in the middle of *Figure 4.78* that an increment attempt only got as far as counter CPUDO = 3, before time TPUDO = 0.5 seconds expired and counter CPUDO was reset to zero (0). Each time counter CPUDO reaches NPUDO, counter CHIZ is then incremented (HIZ174 asserts) and counter CPUDO resets (HIZ180 asserts). When counter CHIZ first increments to CHIZ = 1, the corresponding date/time is recorded for possible report logging later.
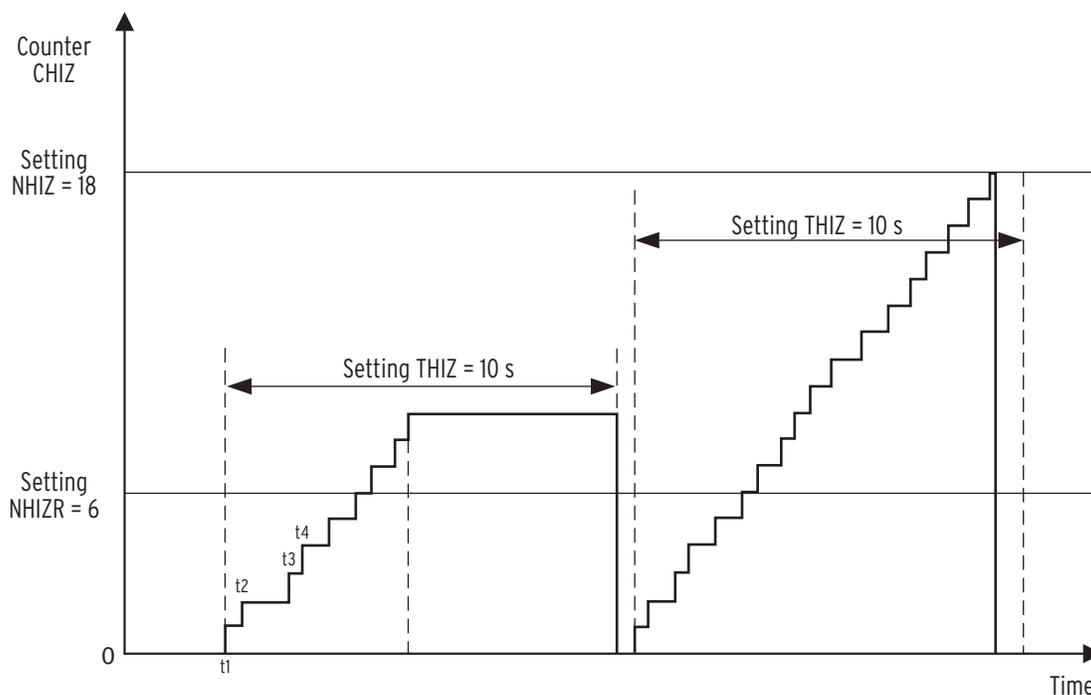
Figure 4.79   Counter CHIZ for High Impedance Ground Fault Detection

Figure 4.79 shows counter CHIZ incrementing, with time stamps t1, t2, t3, and t4 corresponding back to *Figure 4.78*.

If counter CHIZ increments to NHIZ or greater, within THIZ time, then the activity is logged in the HIZ report. Notice in *Figure 4.79* that both incrementing attempts exceed level NHIZR = 6 (CHIZ = Counter HIZ = 9 and CHIZ = Counter HIZ = 18) and thus are displayed in the HIZ report in *Figure 4.76*. Notice that each report entry has a time stamp for Counter HIZ = 1 and a time stamp for the highest Counter HIZ level reached, within time THIZ = 10 seconds. These time stamp differences allow for the determination of the relative activity of ground overcurrent high impedance fault detection. Such analysis may result in modifying settings 50GHIZP, NPUDO, TPUDO, NHIZ, THIZ, or NHIZR.

The first incrementing attempt in *Figure 4.79* only got as far as counter CHIZ = 9, before time THIZ = 10 seconds expired (HIZ192 asserts) and counter CHIZ was reset to zero (0). The second incrementing attempt in *Figure 4.79* reached CHIZ = NHIZ within THIZ time (HIZ175 asserts). Then counter CHIZ was reset to zero (0) (HIZ190 asserts).

Upon asserting HIZ175, Relay Word bit 50GHIZA is asserted and latched; group SELOGIC setting HIZRST, when asserted, resets 50GHIZA. Relay word bit 50GHIZA can be used in custom logic programming to indicate ground overcurrent high-impedance fault detection activity.
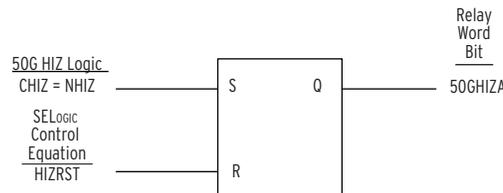
Figure 4.80   50GHIZA Relay Word bit

50G HIZ Application Considerations

Unlike the High-Impedance Fault detection algorithm (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*), the 50G HIZ algorithm does not automatically "tune" to the conditions of the system. Set the algorithm as a high-impedance fault detection alarm until you have determined how the element responds to conditions in your particular application. The following discussion describes how to monitor and adjust the 50G HIZ logic.

Set the 50GHIZP setting equal to the pickup threshold of the 51G element. Arcing faults are intermittent, so the 51G element set the same as the 50GHIZ is not likely to detect the high-impedance fault, but the arcing may cause 50GHIZ activity. Leave the time window settings (TPUDO and THIZ) and threshold settings (NPUDO and NHIZ) at the factory defaults until data are acquired. Make setting NHIZR (report threshold) less than setting NHIZ (fault threshold). This will trigger events that are accessible through the **HIZ** command. The results from the **HIZ** command and conditions reported in the system can then be used to determine if the algorithm should be more or less sensitive.

For example, if there are numerous events logged in the **HIZ** command, but no high-impedance faults are reported in the system, the logic should be made less sensitive. Settings 50GHIZP, NPUDO, NHIZ, and NHIZR can be increased, and time window settings TPUDO and NPUDO can be decreased. On the other hand, if there are no events logged in the **HIZ** command, but high-impedance faults are reported on the system, the logic needs to be made more sensitive. Lower the threshold settings or increase the time window settings. Repeat this process several times until the HIZ results and field data agree.

Section 5

Trip and Target Logic

Trip Logic

The trip logic in *Figure 5.1* provides flexible tripping for single-phase reclosers and three-phase reclosers. Single-phase reclosers can trip/reclose in a single-phase mode (each phase operates independently) or a three-phase mode (all three phases operate in unison). Three-phase reclosers can only trip/reclose in a three-phase mode.

Single-phase reclosers (set for single-phase or three-phase tripping; setting ESPB := Y) can make use of the following logic, also shown in *Figure 5.1*:

➤ Switch-Onto-Fault Trip Logic

➤ Three-Phase Trip Input Logic

➤ Single-Phase Trip Logic

Three-phase reclosers (and single-phase reclosers set for three-phase tripping only; setting ESPB := N) can use the following logic, also shown in *Figure 5.1*:

➤ Switch-Onto-Fault Trip Logic

➤ Three-Phase Trip Input Logic

➤ Three-Phase Trip Output Logic

Table 5.1 includes explanations of the SELOGIC control equation settings in the trip logic in *Figure 5.1*:

Table 5.1 SELOGIC Settings Explanations for Figure 5.1 (Sheet 1 of 2)

SELOGIC Setting	Description
TRSOTF	Switch-Onto-Fault Trip Conditions.
	Setting TRSOTF is supervised by the switch-onto-fault logic output SOTFE (switch-onto-fault logic is described in *Switch-Onto-Fault Logic Output (SOTFE) on page 5.12*). Relay Word bit output SOTFT is provided for testing purposes. Note that the switch-onto-fault tripping routes to both the three-phase trip logic and the single-phase trip logic.
	Switch-onto-fault tripping is a three-phase tripping action, which has its origin in transmission line protection applications. Switch-onto-fault tripping is not used as much in distribution applications.
TRQL3P	Three-Phase Qualified Trip Conditions.
	Setting TRQL3P is supervised by the Disturbance Detector logic output. When the Disturbance Detector bit is not asserted, the qualified trip settings are delayed by two cycles to give the relay self-test time to detect any problem and prevent misoperations. This setting also routes to the single-phase trip logic.

5.2 | Trip and Target Logic
Trip Logic

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Table 5.1 SELᴏɢɪᴄ Settings Explanations for Figure 5.1 (Sheet 2 of 2)

SELᴏɢɪᴄ Setting	Description
TR3P, TR3X	Three-Phase Trip Input Conditions.
	Three-phase trip input conditions settings TR3P and TR3X route to both the three-phase trip output logic (ESPB := N) and the single-phase trip logic (ESPB := Y).
	TR3P and TR3X are functionally equivalent. TR3X is for extra three-phase trip logic and is seen as a supplement to TR3P. For the single-phase trip logic, settings TR3P and TR3X provide convenient locations to insert three-phase trip conditions, rather than repetitively inserting them in each single-phase trip setting (TRA, TRB, and TRC).
ULTR3P	Unlatch Three-Phase Trip Conditions.
	Unlatch three-phase trip conditions setting ULTR3P only routes to the three-phase trip output logic (ESPB := N). Note that if setting ULTR3P is set directly to logical 1 (ULTR3P := 1), then the three-phase trip output logic (Relay Word bit TRIP3P) effectively becomes like the individual single-phase trip output logic arrangements (Relay Word bits TRIPA, TRIPB, and TRIPC).
TRQLA, TRQLB, TRQLC	Single-Phase Qualified Trip Conditions.
	The single-phase qualified trip settings are supervised by the Disturbance Detector logic, similar to Trip setting TRQL3P.
TRA, TRB, TRC	Single-Phase Trip Conditions.
	Single-phase trip conditions settings TRA, TRB, and TRC only route to the single-phase trip logic (ESPB := Y).

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Figure 5.1 Trip Logic

5.4   Trip and Target Logic
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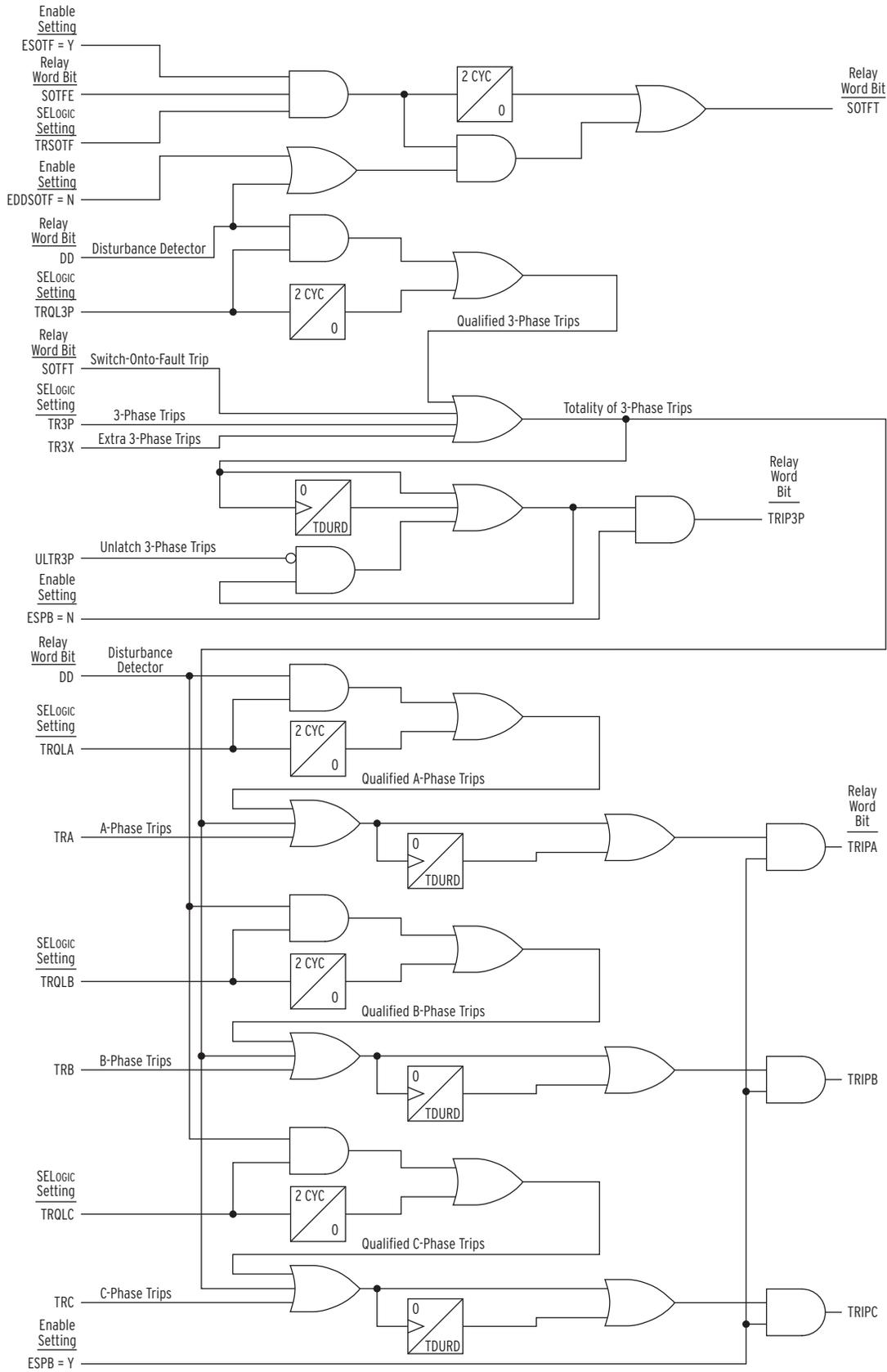
Factory-Default Trip Settings

AVOID SETTING SCENARIOS THAT CAN CAUSE THE TRIP BITS TO GET SEALED IN.
For example, consider the following settings (refer to Figure 5.1): ESPB := Y, TR3P := TRIPA OR TRIPB OR TRIPC, TRA := 50A1, TRB := 50B1, and TRC := 50C1. In this case, TRIPA asserts if 50A1 asserts. This causes TRIP3P (via setting TR3P) to assert, and this in turn asserts TRIPB and TRIPC. Even if 50A1 then deasserts, TRIPA, TRIPB, and TRIPC will remain asserted (sealed in) because of the preceding setting TR3P. Setting TR3P has to be changed (i.e., not set to trip logic output values) for TRIPA, TRIPB, and TRIPC to deassert.

"YELLOW OPERATING HANDLE" TRIP AND DRIVE-TO-LOCKOUT
The factory-default TR3X trip setting (Figure 5.2) and 79DTL3X drive-to-lockout setting (Figure 6.11) are set the same for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), Siemens SDR Triple-Single, Eaton NOVA-TS or NOVA-STS Triple-Single, and Multi-Recloser Interface reclosers. These settings propagate the pulling of a single yellow operating handle (on a single phase) to trip and lockout all three phases.

The factory-default settings for the trip logic in *Figure 5.1* are the following:

TDURD := **40.00 cycles**

TR3P := **51PT OR 51G1T OR PB12_PUL OR OC3**

TR3X := **R_TRIG SV02T** make setting for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), Siemens SDR Triple-Single, and Eaton NOVA-TS or NOVA-STS Triple-Single recloser applications only

TR3X := **R_TRIG SV02T AND AI_CFG** make setting for Multi-Recloser Interface recloser applications only

TRQL3P := **0**

TRSOTF := **0**

ULTR3P := **1** set directly to logical 1

All the other SEL<small>OGIC</small> settings in *Figure 5.1* are set directly to logical 0. See
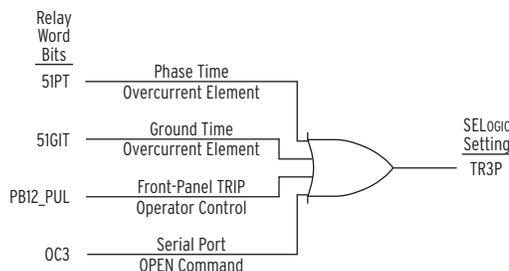
Figure 5.2   Factory-Default Trip Logic Settings

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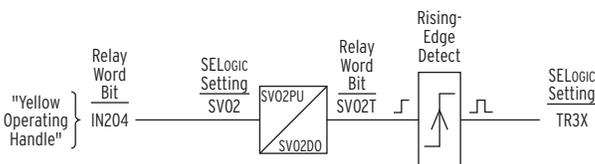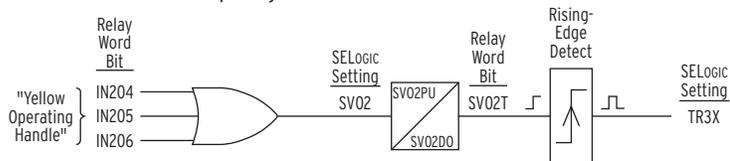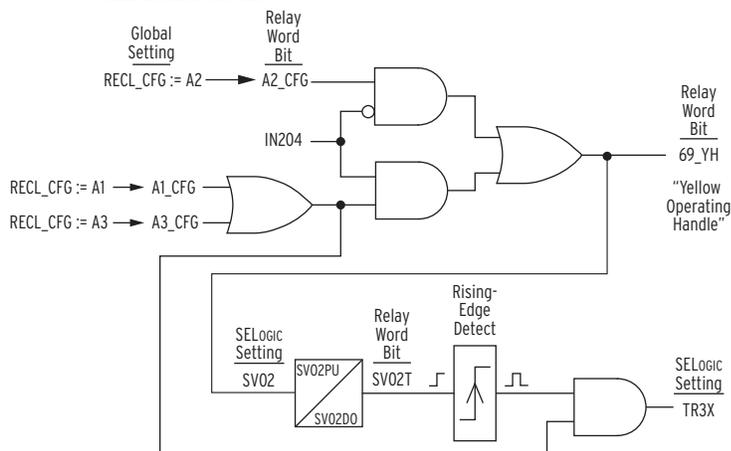
As shown in SELOGIC trip setting TR3P in *Figure 5.2*, overcurrent tripping is by either the phase (51PT) or ground time-overcurrent (51G1T) elements. Each of these overcurrent elements can operate in a fast curve or delay curve mode (see *Section 4*). Additional tripping comes from the front-panel **TRIP** pushbutton (PB12_PUL) or the serial port **OPEN** command (**OC3**).

Yellow Operating Handle
(G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-Pin), Siemens SDR Triple-Single, Eaton NOVA-TS or NOVA-STS Triple-Single, and Multi-Recloser Interface Reclosers)

EMERGENCY THREE-PHASE TRIP WITH SINGLE-PHASE YELLOW OPERATING HANDLE
This subsection explains how a single-phase yellow operating handle pull (to the lock-open position) is converted into a three-phase trip for certain reclosers (factory-default settings).

For the G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), Siemens SDR Triple-Single, and Multi-Recloser Interface reclosers, additional tripping can occur for the time-qualified, rising-edge assertion (SELOGIC operator R_TRIG) of input IN204. Input IN204 detects the operation of any one of the yellow operating handles on the single-phase units of the recloser (see *Figure 2.54*, *Figure 2.72*, and *Figure 2.80*). For the Eaton NOVA-TS or NOVA-STS Triple-Single recloser, inputs IN204, IN205, or IN206 detect the operation of the yellow operating handles on phase 1, 2, or 3, respectively (see *Figure 2.67*). These manual trip conditions are propagated to all three phases, via SELOGIC trip setting TR3X. Each single-phase unit has its own yellow operating handle; operation of this handle manually opens up the single-phase unit and effectively locks it out.

The yellow operating handle could be used in an emergency situation, where tripping of all three phases is necessary. In such a situation, it would take too long to manually operate each individual yellow operating handle on each single-phase recloser unit. Thus, the factory-default TR3X setting propagates the trip operation of one yellow operating handle to the other two single-phase recloser units.

The factory-default settings for timer SV02T in *Figure 5.2* are SV02PU := 5.00 cycles and SV02DO := 60.00 cycles. The 5 cycles setting gives time for the yellow operating handle actuated single-phase unit to lock out its trip/close circuit, before a trip signal is issued to all the units, including the one that is locked out. The 60 cycles setting helps prevent any spurious signal dropout and subsequent apparent rising edge, thus avoiding any unintentional trip.

69_YH Relay Word Bit for Multi-Recloser Interface

Review *Table 2.6* and accompanying footnotes [b] and [d].

For the reclosers in *Table 2.6* with Global setting RECL_CFG := A1 or A3, and which include per-phase handles, pulling a yellow operating handle on a single phase of the recloser to the lock-open position causes the following:

➤ the single phase of the recloser to open, if not already open

➤ the corresponding 69 contact of Trip/Close circuitry in *Figure 2.79* (e.g., contact 69_1) to open, thus open circuiting the trip/close circuit of that phase

➤ the corresponding auxiliary (or status) 69 contact in *Figure 2.80* (e.g., contact 69_1) to close, energizing input IN204. This causes Relay Word bit 69_YH to assert in the Multi-Recloser Interface portion of *Figure 5.2*.

5.6 | Trip and Target Logic
Trip Logic

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For the reclosers in *Table 2.6* with Global setting RECL_CFG := A2, pulling the sole yellow operating handle of the recloser to the lock-open position causes:

➤ all three phases of the recloser to open, if not already open

➤ all three 69 contacts in *Figure 2.79* to open, thus open circuiting the trip/close circuits of all three phases

➤ the corresponding 69 contact in *Figure 2.80* to open, de-energizing input IN204. This causes Relay Word bit 69_YH to assert in the Multi-Recloser Interface portion of *Figure 5.2*.

Thus, Relay Word bit 69_YH indicates that a yellow operating handle has been pulled to the lock-open position, for the Multi-Recloser Interface.

The operated phases cannot be closed until their corresponding yellow operating handle is reset again. Resetting the yellow operating handle does not cause the recloser phase(s) to close, but rather returns the corresponding 69 contact(s) to their original state (e.g., contact 69_1 in *Figure 2.79* closes)—then the phase(s) can be closed by the SEL-651R-2.

Qualified Trip Conditions Settings

The SEL-651R-2 has self-test functions to detect most hardware problems and prevent misoperation. A small number of transient memory or processor errors may not be detected. The qualified trip conditions settings (TRQL3P, TRQLA, TRQLB and TRQLC) and setting EDDSOTF switch-onto-fault supervision improve security for these transient conditions without increasing relay operating time under most fault conditions. The qualified trip conditions settings are supervised by the disturbance detector logic, as shown in *Figure 5.1*. The disturbance detector (DD) logic detail is shown in *Figure 5.3*. For example, when the SEL-651R-2 evaluates the TRQL3P setting to logical 1, the relay trips immediately if the DD Relay Word bit is already asserted. If DD is not asserted, the relay waits as long as two cycles for DD to assert. If the TRQL3P setting remains asserted the relay trips after the timer expires.
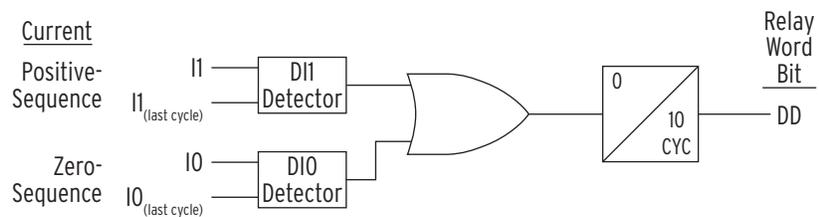
Figure 5.3   Disturbance Detector Logic

The sensitive disturbance detector monitors changes in the magnitude and angle of the positive- and zero-sequence currents and deems a fault condition exists if there is a noticeable change in at least one of these values. The DD element also contains a 10-cycle dropout timer to maintain a logical 1 for a reasonable period after a disturbance is detected. Thus, using the qualified trip conditions settings for instantaneous overcurrent elements will almost never increase tripping time.

Security is improved when a qualified trip conditions setting is asserted momentarily because of a transient memory or processor error, but the disturbance detector does not assert. If the qualified trip conditions setting resets before the two-cycle timer expires, no TRIP is issued.

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Use the qualified trip conditions settings with instantaneous elements, such as in the following setting:

TRQL3P := **50P1**

Overcurrent elements that contain an intentional time delay may be used in the qualified trip conditions settings. In certain conditions, such as during bench testing with delays set longer than 10 cycles, the disturbance detector element may deassert before the time-delayed element asserts in the qualified trip conditions settings. This adds two cycles to the overall trip time.

For example, if setting TRQL3P contains a negative-sequence time-overcurrent element

TRQL3P := **... OR 51QT**

the observed trip time may be as many as 2 cycles longer than the expected time-overcurrent characteristic. For backup protection delays lasting several seconds, this extra time is of no consequence. If this extra delay is not desirable, use the time-delayed elements in the unsupervised trip settings TR3P or TR3X instead.

Elements that assert for nonfault conditions, such as a **BREAKER OPEN** command or **OPERATOR CONTROL** pushbutton trip conditions, should not be used in the qualified trip conditions settings because the asserted condition may only exist for one processing interval and the DD bit will often be quiescent. This situation will sometimes result in a nontrip. Use the unsupervised trip settings TR3P or TR3X for automation or control tripping instead.

Setting EDDSOTF := Y enables similar supervision for the switch-onto-fault logic. See *Disturbance Detector Supervision for Switch-Onto-Fault Logic on page 5.13* for more information.

Minimum Trip Duration Timer

The Minimum Trip Duration Timer (with setting TDURD) establishes the minimum time duration for which the TRIP3P, TRIPA, TRIPB, and TRIPC Relay Word bits assert in *Figure 5.1*.

The factory-default setting of TDURD := 40.00 cycles covers the operation requirements of all compatible reclosers. This 40-cycle minimum trip time effectively adds on to any open-interval time for autoreclosing (see *Skip-Shot and Stall Open-Interval Timing Settings (79SKP and 79STL, Respectively) on page 6.29*; setting 79STL3P := TRIP3P). If the recloser is not a motor-operated recloser (see *Motor-Operated Traditional Retrofit Reclosers on page 2.60*) and this 40 cycles is too much additional delay for open-interval timing, then set:

TDURD := **12 cycles**

ULTR3P := **NOT 52A3P** (if recloser is also a Traditional Retrofit standard recloser)

As shown in the time line example in *Figure 5.4*, the Minimum Trip Duration Timer (with setting TDURD) outputs a logical 1 (Signal 2) for a time duration of TDURD cycles any time it sees a rising edge on its input (logical 0 to logical 1 transition on Signal 1), if it is not already timing (timer is reset). If Signal 1 in *Figure 5.4* is logical 1 beyond the TDURD time, Signal 3 remains asserted at logical 1 for as long as Signal 1 remains at logical 1, regardless of other trip logic conditions.

5.8 | Trip and Target Logic
Trip Logic

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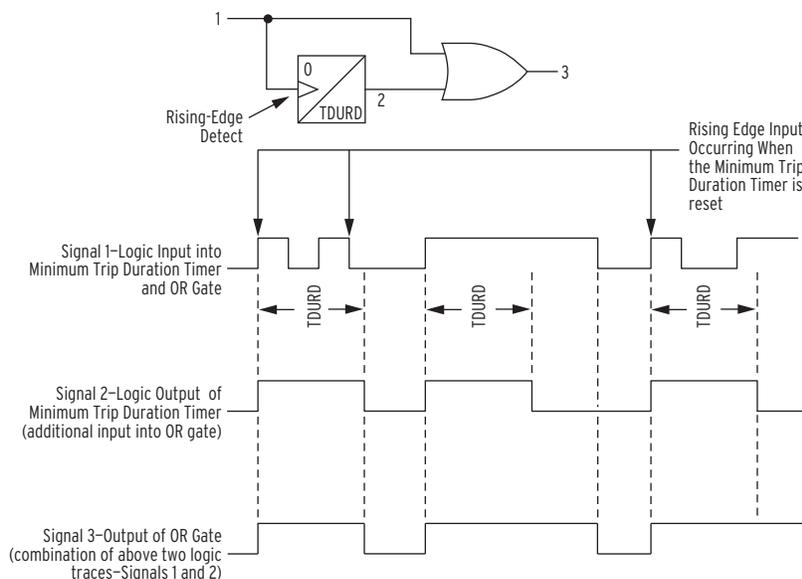
Figure 5.4   Minimum Trip Duration Timer Operation

Program Outputs for Tripping the Recloser

See *Trip and Close Mapping and Output Logic on page 7.31* for more information on programming outputs for tripping the recloser. Relay Word bits TRIP3P, TRIPA, TRIPB, and TRIPC from *Figure 5.1* are used to program trip outputs.

Trip Output Logic Used in Other Settings

In addition to operating trip outputs, the TRIP3P, TRIPA, TRIPB, and TRIPC Relay Word bits from *Figure 5.1* are traditionally used in a number of other SELOGIC control equations settings, such as the following (discussed in *Section 6*):

➤ ULCL (unlatch close settings)

➤ 79RI (reclose initiate settings)

➤ 79DTL (drive-to-lockout settings)

➤ 79STL (stall open interval timing settings)

Change the Trip Settings—Check Other Settings

Any time any of the SELOGIC settings in *Figure 5.1* are changed/modified, the following SELOGIC control equations should be checked or considered for modification:

Table 5.2   Settings to Modify When Modifying Trip Logic Settings (Sheet 1 of 2)

Setting	Modification
79DTL3P, 79DTL3X	Drive-to-lockout settings—see *Section 6*
	For example, if frequency element 81D1T is added to the three-phase trip setting (TR3P := … OR 81D1T …), but no autoreclosing should occur after an underfrequency load-shedding trip, then frequency element 81D1T should be added to the three-phase drive-to-lockout setting (79DTL3P := … OR 81D1T …).
50xTC-51xTC	Torque control for overcurrent elements—see *Section 4*
	For example, if ground time-overcurrent element 51G2T is added to the factory-default trip settings (TR3P := … 51G2T …), check its corresponding torque-control setting (51G2TC). Should it be enabled all the time (51G2TC := 1)? Should it be controlled by the **GROUND ENABLED** operator control (51G2TC := LT01; see *Table 11.9*).

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Trip and Target Logic 5.9
Pole Open Logic

Table 5.2   Settings to Modify When Modifying Trip Logic Settings (Sheet 2 of 2)

Setting	Modification
T01_LED–T24_LED	Programmable target LEDs *Front-Panel Target LEDs on page 5.13* shows the correlation between tripping elements in factory-default SELOGIC control equation trip settings and the programmable front-panel target LEDs. For example, if ground time-overcurrent element 51G2T is added to the three-phase trip settings (TR3P := … OR 51G2T …), it should perhaps be added to the FAST CURVE or DELAY CURVE trip target LED setting (e.g., T09_LED := … OR 51G2T …) and its pickup indication (51G2) should be added to the GROUND fault type target LED setting (T06_LED := … OR 51G2 …). An additional example, if frequency element 81D1T is added to the factory-default trip setting (TR3P := … OR 81D1T …), then frequency element 81D1T should be assigned to the dedicated FREQUENCY trip target LED setting (T11_LED := 81D1T).
ER	Event report trigger conditions—see *Section 12* For example: if residual ground time-overcurrent element 51G2T is added to the three-phase trip settings (TR3P := … OR 51G2T …), consider adding its pickup indication (51G2) to the event report trigger conditions setting (ER := … OR R_TRIG 51G2 …). A rising edge operator (R_TRIG) is added on the front of the element.
FAULT	Fault indication-used to help determine phases involved in faults and to block certain metering functions during faults For example, if residual ground time-overcurrent element 51G2T is added to the three-phase trip settings (TR3P := … OR 51G2T …), consider adding its pickup indication (51G2) to the fault indication setting (FAULT := … OR 51G2 …).

Pole Open Logic

NOTE: The logic in Figure 5.6 can be used for load current detection, independent of the pole open logic in Figure 5.5.

Combinations of the following items make up the single-pole open and three-pole open logic in *Figure 5.5*.

➤ load current detection

➤ breaker (recloser) pole status (52a auxiliary contacts)

This logic verifies that the poles/phases of the breaker (recloser) are open.

Figure 5.6 shows the load current detection logic, with available single-phase values. Phase pickup setting 50LP is set below minimum load current levels.

In *Figure 5.5*, the breaker (recloser) type setting BKTYP makes the large demarcation for the following recloser types:

➤ BKTYP := 1 (single-phase)

➤ BKTYP := 3 (three-phase)

MULTI-RECLOSER INTERFACE
Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface on page 2.93.

In general, the following is required to indicate single-pole open (SPO) or three-pole open (3PO) conditions:

➤ an absence of current (Relay Word bit 50Lx deasserted)

➤ a breaker auxiliary contact indication of open recloser poles (Relay Word bit 52Ax deasserted).

5.10 | Trip and Target Logic
Pole Open Logic

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The 3POD and SPOD dropout time settings qualify circuit breaker closure and are usually set around one cycle.
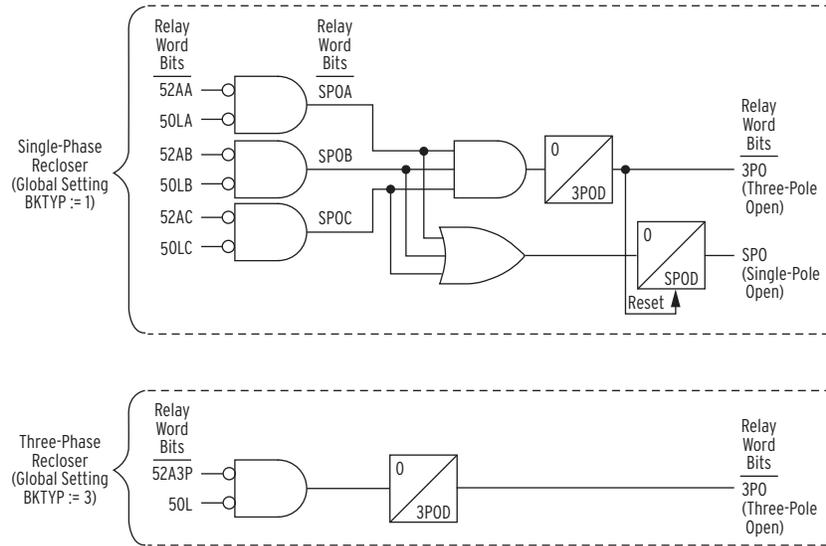
Figure 5.5   Pole Open Logic
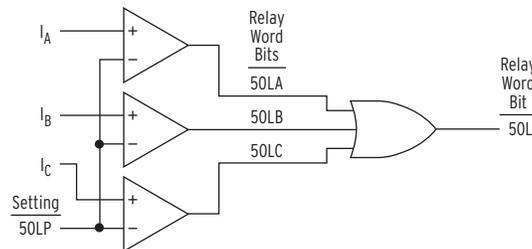
Figure 5.6   Load Current Detection Logic

Overcurrent Element Torque-Control Setting Application

If a single-phase recloser is operating in a single-phase trip/reclose mode, one or two phases can trip open, while at least one phase remains closed, carrying load current. This can result in large unbalance current (zero-sequence and negative-sequence current). To keep zero-sequence (ground) and negative-sequence overcurrent elements from operating for this unbalance situation, the SPO (single-pole open) Relay Word bit is entered in the respective torque-control SELOGIC settings of these overcurrent elements. The SPO Relay Word bit is programmed in the torque-control SELOGIC settings such that when SPO asserts (= logical 1), the torque-control SELOGIC settings effectively deassert (= logical 0). For example, set a ground time-overcurrent element as follows:

    51GITC := **... AND NOT (SPO AND SPE)**

SPE asserts to logical 1 when Group setting ESPB := Y (enabling single-phase settings/operation). This matches the recommended torque-control settings for ground time-overcurrent elements in SEL QuickSet Design Template Guide (LDG002-01), *Single-Phase Operation Setting for the SEL-651R 32-Pin Recloser Control*.

The three-pole open logic output (Relay Word bit 3PO) is used in the following switch-onto-fault logic subsection.

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Trip and Target Logic 5.11
Switch-Onto-Fault (SOTF) Trip Logic

Switch-Onto-Fault (SOTF) Trip Logic

Switch-onto-fault (SOTF) trip logic is enabled with Group setting
ESOTF := Y and provides a programmable time window for selected elements
to trip right after the circuit breaker/recloser closes. Switch-onto-fault implies
that a recloser is closed into an existing fault condition.

For example, suppose safety grounds are accidentally left attached to a line
after a clearance. If the recloser is closed into such a condition, the resulting
fault needs to be cleared right away and reclosing blocked. An instantaneous
overcurrent element is usually set to trip in the SOTF trip logic.

For added security, the SEL-651R-2 features a selectable disturbance detector
supervision function on the switch-onto-fault trip condition. Enable this logic
by setting EDDSOTF = Y. See *Disturbance Detector Supervision for Switch-
Onto-Fault Logic* for more detail.

Refer to the SOTF trip logic in *Figure 5.1*. This logic permits immediate
tripping if the following are all true:

> ➤ An element asserts in SEL<small>OGIC</small> control equation trip setting
>   TRSOTF
>
> ➤ Relay Word bit SOTFE is asserted to logical 1
>
> ➤ Setting EDDSOTF := N

Relay Word bit SOTFE (the output of the SOTF logic) provides the effective
time window for an element in trip setting TRSOTF (e.g., TRSOTF := 50P2)
to trip after the circuit breaker closes. *Figure 5.7* and the following discussion
describe the SOTF logic.
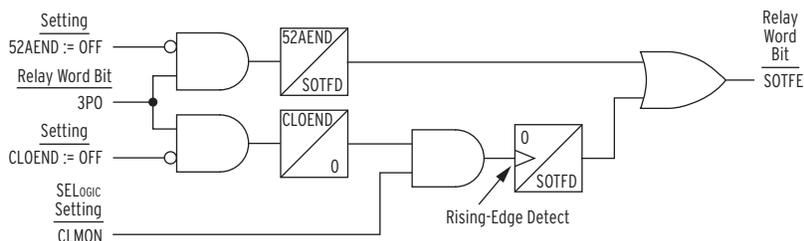
Figure 5.7   Switch-Onto-Fault (SOTF) Logic

Circuit Breaker Operated SOTF Logic

Circuit-breaker operated switch-onto-fault logic is enabled by making time
setting 52AEND (52AEND ≠ OFF). Time setting 52AEND qualifies the three-
pole open (3PO) condition and then asserts Relay Word bit SOTFE:
SOTFE = logical 1.

Note that SOTFE is asserted when the circuit breaker is qualified as open (see
Figure 5.8). This allows elements set in the SEL<small>OGIC</small> control equation trip
setting TRSOTF to operate if a fault occurs when the circuit breaker is open.
In such a scenario (e.g., flashover inside the circuit breaker tank), the tripping
via setting TRSOTF cannot help in tripping the circuit breaker, which is
already open, but can initiate breaker failure protection, if a breaker failure
scheme is implemented in the SEL-651R-2 or externally.

5.12 | Trip and Target Logic
Switch-Onto-Fault (SOTF) Trip Logic

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Figure 5.8   SOTF Logic Output (52AEND ≠ OFF)

When the circuit breaker is closed, the 3PO condition deasserts (3PO = logical 0) after the 3POD dropout time (setting 3POD is usually set for no more than a cycle). The SOTF logic output, SOTFE, continues to remain asserted at logical 1 for dropout time SOTFD.

Close Bus Operated SOTF Logic

Close bus operated switch-onto-fault logic is enabled by making time setting CLOEND (CLOEND ≠ OFF). Time setting CLOEND qualifies the three-pole open (3PO) condition, indicating that the circuit breaker is open.

Circuit breaker closure is detected by monitoring the dc close bus. This is accomplished by wiring an optoisolated input on the SEL-651R-2 (e.g., IN101) to the dc close bus. When a manual close or automatic reclosure occurs, optoisolated input IN101 is energized. SELOGIC control equation setting CLMON (close bus monitor) monitors the optoisolated input IN101:

CLMON := **IN101**

When optoisolated input IN101 is energized, CLMON asserts to logical 1. At the instant that optoisolated input IN101 is energized (close bus is energized), the circuit breaker is still open (3PO = logical 1), so the output of the CLOEND timer continues to be asserted to logical 1. Thus, the ANDed combination of these conditions latches in the SOTFD timer (see *Figure 5.9*). The SOTFD timer outputs a logical 1 for a time duration of SOTFD cycles any time it sees a rising edge on its input (logical 0 to logical 1 transition), if it is not already timing. The SOTF logic output, SOTFE, asserts to logical 1 for SOTFD time, like the edge-triggered timer in *Figure 5.4*.
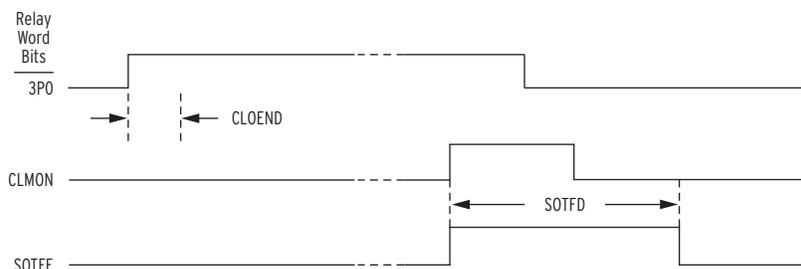
Figure 5.9   SOTF Logic Output (CLOEND ≠ OFF)

Switch-Onto-Fault Logic Output (SOTFE)

Relay Word bit SOTFE is the output of the circuit-breaker operated SOTF logic or the close bus operated SOTF logic described previously. Time setting SOTFD in each of these logic paths provides the effective time window for the overcurrent elements in SELOGIC control equation trip setting TRSOTF to trip after the circuit breaker closes (see *Figure 5.1*). Time setting SOTFD is usually set around 30 cycles.

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Trip and Target Logic 5.13
Front-Panel Target LEDs

Disturbance Detector Supervision for Switch-Onto-Fault Logic

The SEL-651R-2 features a selectable disturbance detector supervision function on the switch-onto-fault trip condition. Enable this logic by setting EDDSOTF = Y (see *Figure 5.1*).

When EDDSOTF = N, the switch-onto-fault logic works with no DD supervision (output of *Figure 5.3*), and the relay immediately asserts SOTFT and issues a TRIP when TRSOTF evaluates to logical 1 with SOTFE asserted.

When EDDSOTF = Y, the relay checks the state of the Disturbance Detector (DD) Relay Word bit when TRSOTF evaluates to logical 1, with SOTFE asserted:

➤ If DD is asserted, the relay immediately asserts the SOTFT output, which causes an immediate trip.

➤ If DD is not asserted and the TRSOTF and SOTFE conditions remain asserted, the relay delays the SOTFT assertion for as many as 2 cycles (until the DD element asserts or until the 2-cycle wait time expires).

➤ If one of the TRSOTF or SOTFE conditions deassert before the 2-cycle timer expires and the DD bit does not assert, no trip is issued. This provides a security improvement in cases where an element in the TRSOTF equation was transient.

The disturbance detector is described in greater detail in *Qualified Trip Conditions Settings on page 5.6*.

The sensitive disturbance detector will almost always be asserted before a high-set overcurrent element asserts for a new fault condition. The DD element also contains a 10-cycle dropout timer to maintain a logical 1 for a reasonable period after a disturbance is detected. In other words, using the EDDSOTF := Y setting while using instantaneous overcurrent elements in the TRSOTF equation will almost never impair tripping speed.

Front-Panel Target LEDs

Refer to *Figure 11.13* for the layout of the front-panel target LEDs. The functions and associated settings for these target LEDs are described in *Table 5.3*.

Not All Front-Panel Target LEDs Are Set and Functional

Even though there is a front-panel inscription for every target LED, not all of these LEDs are programmed from the factory—some are just left set to logical 0. For example, the SELOGIC setting T07_LED for the SEF-labeled (sensitive-earth-fault) LED is programmed T07_LED := 0.

Table 5.3   SEL-651R-2 Front-Panel Target LED Labels and Settings (Factory Defaults) (Sheet 1 of 2)

Label/Definition	LED Color (Front-Panel Setting) R = red, G = green, A = amber[a]	Logic Input (Front-Panel SELOGIC Setting)	Latch In On Trip? (Front-Panel Setting)	Logic Output (Relay Word bit)
ENABLED	LEDENAC := G			EN
TRIP	LEDTRAC := R			TRIPLED
SUPPLY —control power source OK	T01LEDC := G	T01_LED := PWR_SRC1	T01LEDL := N	TLED_01

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Front-Panel Target LEDs

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Table 5.3   SEL-651R-2 Front-Panel Target LED Labels and Settings (Factory Defaults) (Sheet 2 of 2)

Label/Definition	LED Color (Front-Panel Setting) R = red, G = green, A = amber[a]	Logic Input (Front-Panel SELOGIC Setting)	Latch In On Trip? (Front-Panel Setting)	Logic Output (Relay Word bit)
BATTERY PROBLEM	T02LEDC := R	T02_LED := BTFAIL	T02LEDL := N	TLED_02
A FAULT —A-phase involved	T03LEDC := R	T03_LED := PHASE_A	T03LEDL := Y	TLED_03
B FAULT —B-phase involved	T04LEDC := R	T04_LED := PHASE_B	T04LEDL := Y	TLED_04
C FAULT —C-phase involved	T05LEDC := R	T05_LED := PHASE_C	T05LEDL := Y	TLED_05
GROUND —involved in fault	T06LEDC := R	T06_LED := 51G1	T06LEDL := Y	TLED_06
SEF —SEF element tripped for fault	T07LEDC := R	T07_LED := 0	T07LEDL := Y	TLED_07
FAST CURVE —trip	T08LEDC := R	T08_LED := NOT (51G1S) AND 51G1T OR NOT (51PS) AND 51PT	T08LEDL := Y	TLED_08
DELAY CURVE —trip	T09LEDC := R	T09_LED := 51G1S AND 51G1T OR 51PS AND 51PT	T09LEDL := Y	TLED_09
HIGH CURRENT —inst. or def.-time overcurrent trip	T10LEDC := R	T10_LED := 0	T10LEDL := Y	TLED_10
OVER/UNDERFREQUENCY —trip	T11LEDC := R	T11_LED := 0	T11LEDL := Y	TLED_11
OVER/UNDERVOLTAGE —trip	T12LEDC := R	T12_LED := 0	T12LEDL := Y	TLED_12
79 RESET —reclosing relay state	T13LEDC := G	T13_LED := 79RS3P	T13LEDL := N	TLED_13
79 CYCLE —reclosing relay state	T14LEDC := R	T14_LED := 79CY3P	T14LEDL := N	TLED_14
79 LOCKOUT —reclosing relay state	T15LEDC := R	T15_LED := 79LO3P	T15LEDL := N	TLED_15
ABOVE MIN TRIP —current level	T16LEDC := R	T16_LED := 51P OR 51G1	T16LEDL := N	TLED_16
COLD LOAD SCHEME ON —scheme active	T17LEDC := R	T17_LED := 0	T17LEDL := N	TLED_17
REVERSE POWER —flow	T18LEDC := R	T18_LED := 0	T18LEDL := N	TLED_18
VAY ON	T19LEDC := R	T19_LED := 59YA1	T19LEDL := N	TLED_19
VBY ON	T20LEDC := R	T20_LED := 59YB1	T20LEDL := N	TLED_20
VCY ON	T21LEDC := R	T21_LED := 59YC1	T21LEDL := N	TLED_21
VAZ ON	T22LEDC := R	T22_LED := 0	T22LEDL := N	TLED_22
VBZ ON	T23LEDC := R	T23_LED := 0	T23LEDL := N	TLED_23
VCZ ON	T24LEDC := R	T24_LED := 0	T24LEDL := N	TLED_24

[a] The target LED color settings LEDTRAC (for the TRIP LED) and TxxLEDC (for the SUPPLY through VCZ ON LEDs) are only present when tricolor LEDs are ordered for the SEL-651R-2. If tricolor LEDs are not ordered, then these LEDs are all red, except for the two green LEDs (SUPPLY and 79 RESET). The ENABLED LED always comes as a tricolor LED.

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Trip and Target Logic 5.15
Front-Panel Target LEDs

Front-Panel Target LEDs ENABLED and TRIP

The **ENABLED** and **TRIP** LEDs (top of *Table 5.3*) are not programmable except for choosing the LED illuminated color; they are fixed-function LEDs. The **ENABLED** LED illuminates when the SEL-651R-2 is powered correctly, is functional, and has no self-test failures. The **TRIP** LED illuminates and latches in at the rising-edge of any trip that comes from the trip logic in *Figure 5.1*.

Programmable Front-Panel Target LEDs

Refer to *Table 5.3* and *Figure 5.10*.

The LEDs in *Table 5.3*, labeled by default as SUPPLY through VCZ ON, are programmable via the front-panel settings shown in *Table 5.3*. SELOGIC setting T*xx*_LED is the condition/element being monitored. Setting T*xx*LEDL determines whether the state of the condition/element being monitored is latched in on trip (setting T*xx*LEDL := Y) or not (setting T*xx*LEDL := N).

For an individual LED to be latched in (constantly illuminated) at the occurrence of a trip, the following have to be true:

➤ "latch in on trip?" setting T*xx*LEDL := Y

➤ a new trip has to occur, from the trip logic in *Figure 5.1*

➤ the SELOGIC setting T*xx*_LED (the condition/element being monitored) has to be asserted (effectively, T*xx*_LED = logical 1) sometime during a 1.5 cycle time window. The time window starts at the occurrence of the trip

Latched-in LEDs, including the dedicated **TRIP** LED, remain latched in (constantly illuminated) until one of the following occurs:

➤ a new trip occurs, from the trip logic in *Figure 5.1*

➤ or the reset trip-latched LEDs on close setting RSTLED := Y and the recloser closes (any phase) and no trip is present

➤ or a target reset condition occurs and no trip is present

A target reset condition can be any of the following:

➤ front-panel **TARGET RESET** pushbutton

➤ **TAR R** serial port command

➤ target reset SELOGIC setting RSTTRGT, which is also available as a Relay Word bit

➤ target reset through DNP3 or Modbus protocols

Latched-in LEDs retain their state, even when the relay is powered down, then powered up again.

To program an LED to not be latched in on trip, but to just follow some condition/element, make the following settings for the particular LED:

➤ "latch in on trip?" setting T*xx*LEDL := N

➤ SELOGIC setting T*xx*_LED (the condition/element being monitored)

Then, when T*xx*_LED = logical 1, the LED illuminates (Relay Word bit output TLED_*xx* = logical 1). When T*xx*_LED = logical 0, the LED extinguishes (Relay Word bit output TLED_*xx* = logical 0).

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Front-Panel Target LEDs

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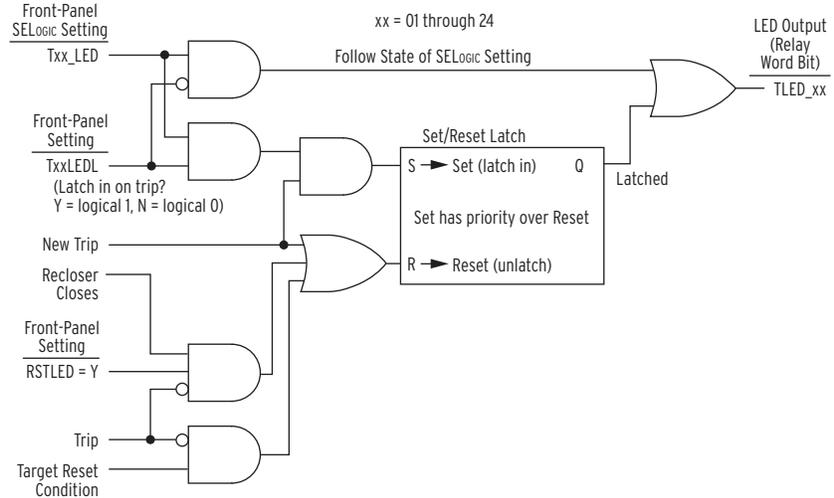
Figure 5.10   Programmable Front-Panel Target LED Logic

Other Uses for Front-Panel Target LED Relay Word Bits

The LED logic outputs, Relay Word bits TLED*xx*, actually drive the front-panel target LEDs. These Relay Word bits can also be used to drive other things, such as output contacts for a discrete-wired SCADA system. For example, to route phase/ground involvement in a fault to SCADA, set separate output contacts individually to TLED_03, TLED_04, TLED_05, and TLED_06, respectively (e.g., OUT101 := TLED_03, OUT102 := TLED_04, OUT103 := TLED_05, OUT104 := TLED_06; see *Table 5.3*).

Correlation Between Trip Target LEDs and Trip Settings

The SELOGIC control equation factory-default trip settings are shown in *Figure 5.2*. The following LED descriptions discuss how some of the elements that make up the factory-default trip settings are incorporated into LED settings. If trip settings are changed, front-panel target LED settings changes may also be needed. Front-panel target LED relabeling may also be needed, especially for custom schemes (see SEL-651R-2 Configurable Labels instructions).

TRIP LED

As discussed earlier, the **TRIP** LED illuminates and latches in at the rising-edge of any trip, single-phase or three-phase, that comes from the trip logic in *Figure 5.1*.

A Fault, B Fault, and C Fault LEDs

The logic for determining phase involvement for a fault depends on if one of the following conditions are true:

➤ All three phases are initially closed.

➤ Only one or two phases are initially closed (and therefore two or one phases are already open, respectively).

Group setting ESPB enables single-phase operation for reclosers that have such capability. Thus, the condition of "only one or two phases are initially closed" is indicative of Group setting ESPB:= Y. Of course, all three phases can also initially be closed, too, for a recloser with single-phase operation capability.

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Trip and Target Logic 5.17
Front-Panel Targets

With all three phases initially closed (and Group setting ESPB:= Y or N), when a fault and subsequent trip occur, phase involvement is determined by logic using Relay Word bits FSA, FSB, and FSC. A phase, negative-sequence, or ground-overcurrent element also has to be picked up for this phase involvement logic to work. The output of this embedded logic is the selective assertion of Relay Word bits PHASE_A, PHASE_B, or PHASE_C used in factory-default phase targeting LED settings:

> T03_LED:= **PHASE_A** (A PHASE LED)
>
> T04_LED:= **PHASE_B** (B PHASE LED)
>
> T05_LED:= **PHASE_C** (C PHASE LED)

In addition, the fault must be present for a little longer than 1 cycle (after the control issues a trip) for reliable phase targeting (via this phase involvement logic using Relay Word bits FSA, FSB, and FSC). Inaccurate phase targeting is most noticeable during control testing if currents are immediately turned off when a trip is issued. This results in inaccurate phase targeting because fault currents do not continue to be present as in a normal recloser setup, where fault current would continue until the recloser opens.

With all three phases initially closed, if there is a phase-to-phase or three-phase fault, SELOGIC control equation setting FAULT has to be picked up in order for the appropriate phases to be deemed as being involved (via this phase involvement logic using Relay Word bits FSA, FSB, and FSC). SELOGIC control equation setting FAULT := 51P OR 51G1 in the factory-default settings. Relay Word bits 51P and 51G1 are pickup indicators of the factory-set time-overcurrent elements. Control equation setting FAULT also controls other functions (see *SELOGIC Control Equation Setting FAULT*).

There is not necessarily a one-to-one correspondence between FSA and PHASE_A, etc., for various fault types. Relay Word bits FSA, FSB, and FSC are also used in fault location logic and to help determine event type in event report summaries. Relay Word bits FSA, FSB, and FSC have no direct customer use and should not be used in custom logic.

In contrast to the preceding discussion (determining phase involvement for a fault when all three phases are initially closed), now consider the scenario of Group setting ESPB:= Y and one or two phases are initially closed (and therefore two or one phases are already open, respectively). When a fault and subsequent trip occur in such a scenario, phase involvement is then determined directly by what trip-related Relay Word bits (TRIPA, TRIPB, or TRIPC) assert. Phase involvement logic using Relay Word bits FSA, FSB, and FSC is not used in this scenario—instead Relay Word bits TRIPA, TRIPB, and TRIPC directly assert Relay Word bits PHASE_A, PHASE_B, or PHASE_C, respectively.

Relay Word bits PHASE_A, PHASE_B, and PHASE_C assert only for a processing interval during a trip, when controlled in one of the following ways:

> ➤ By phase involvement logic using Relay Word bits FSA, FSB, and FSC
>
> ➤ Directly by Relay Word bits TRIPA, TRIPB, and TRIPC

as previously discussed. Therefore, **A PHASE**, **B PHASE**, and **C PHASE** LEDs make use of the trip latching logic in *Figure 5.10*.

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Front-Panel Target LEDs

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GROUND LED

Note in *Table 5.3* that the **GROUND** LED directly contains the pickup indicator of the ground time-overcurrent tripping element (TR3X := … OR 51G1T …), indicating ground involvement in the fault:

> T06_LED := **51G1**

FAST CURVE and DELAY CURVE LEDs

The phase and ground time-overcurrent elements (51PT and 51G1T, respectively) each switch between operating as a fast curve and as a delay curve. This switching is indicated by the 51PS and 51G1S Relay Word bits, respectively, for elements 51PT and 51G1T (51xS = logical 0, indicates fast curve operating mode; 51xS = logical 1, indicates delay curve operating mode). See *Time-Overcurrent Elements on page 4.13* for more details.

> T08_LED := **NOT(51G1S) AND 51G1T OR NOT(51PS) AND 51PT**

> T09_LED := **51G1S AND 51G1T OR 51PS AND 51PT**

ABOVE MIN TRIP LED

The monitored minimum trip pickups are for the phase and ground time-overcurrent elements (51PT and 51G1T, respectively). When current is above one of the pickup indicators, the **ABOVE MIN TRIP** LED illuminates.

> T16_LED := **51P OR 51G1**

Note that the **ABOVE MIN TRIP** LED does not latch in on trip.

SELᴏɢɪᴄ Control Equation Setting FAULT

SELOGIC control equation setting FAULT has control over or is used in the following:

➤ Front-panel target LEDs A FAULT, B FAULT, and C FAULT (with factory-default front-panel settings, T03_LED through T05_LED set as shown in *Table 5.3*).

➤ Demand metering—FAULT is used to suspend demand metering peak recording (see *Demand Metering on page 8.6*).

➤ Maximum/Minimum metering—FAULT is used to block Maximum/Minimum metering updating (see *Maximum/ Minimum Metering Update and Storage on page 8.18*).

➤ Voltage sag, swell, and interruption elements—FAULT is used to suspend the calculation of Vbase (see *Voltage Sag, Swell, and Interruption Elements on page 4.59*).

The FAULT setting is located in the Global settings class (see *Global Settings on page SET.1*).

Section 6

Close and Reclose Logic

Introduction

Figure 6.1 provides an overview of the close logic and reclosing relay logic described in this section. This logic is provided for the following:

➤ Three-phase reclosers or single-phase reclosers operating in a three-phase mode (Group setting ESPB := N; one reclosing relay available—one for all three phases)

➤ Single-phase reclosers operating in a single-phase mode (Group setting ESPB := Y; three separate reclosing relays available—one for each phase)

Figure 6.1 shows a logic migration:

➤ From main reclosing relay logic

➤ To reclose supervision logic

➤ To close logic

In this section, these logic subsections are discussed in reverse order, starting with Breaker Status Logic. If you are not using the SEL-651R-2 for automatic reclosing, but using it to close the recloser for other close conditions (such as manual close initiation via serial port or optoisolated outputs), focus on the Breaker Status Logic and Close Logic subsections. Note particularly the description of SELOGIC control equation setting CL in the Close Logic subsection.

Breaker Status Logic. Breaker Status Logic shows how the effective breaker status (Relay Word bit 52Ax; x = 3P, A, B, or C) is derived for the required application, three-phase or single-phase mode.

Close Logic. Close Logic describes the final logic that controls the close output. This output controls the recloser for automatic reclosures and other close conditions.

Reclose Supervision Logic. Reclose Supervision Logic describes the logic that supervises automatic reclosing when an open-interval time times out: a final condition check right before the close logic asserts the close output.

Reclosing Relay Logic. Reclose Logic describes the remaining reclosing relay settings and logic needed for automatic reclosing.

NOTE: Reclose enable setting E79 := N defeats the reclosing relay, but does not defeat the ability of the close logic described in the first subsection (Figure 6.3) to close the circuit breaker for other close conditions via SELOGIC control equation setting CL.

6.2 | Close and Reclose Logic
Introduction

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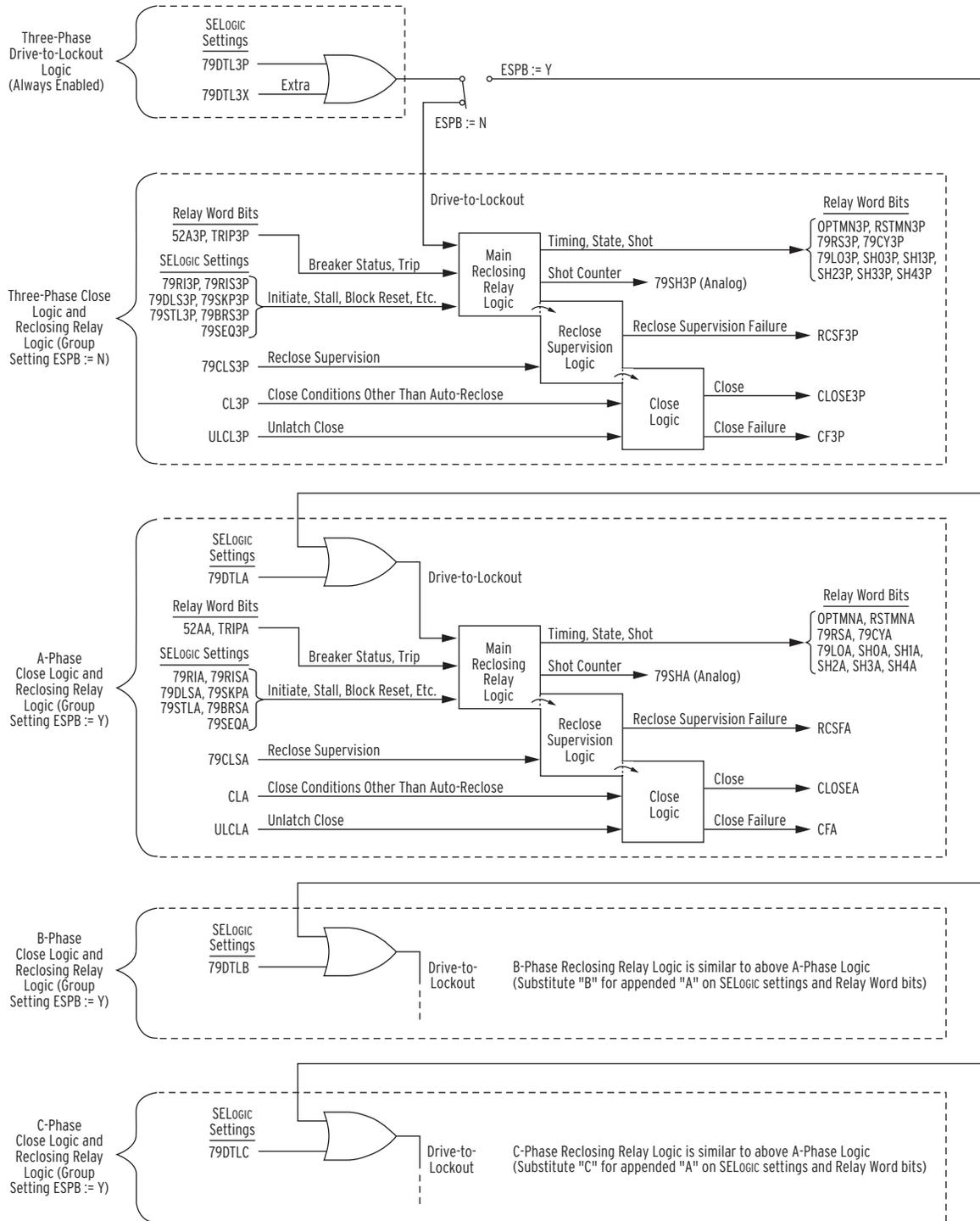
Figure 6.1   Close Logic and Reclosing Relay Logic Overview for Three-Phase and Single-Phase Reclosers

Three-Phase (3P) vs. Single-Phase (A, B, and C)

Figure 6.1 and *Figure 6.2* show specific SELOGIC settings and Relay Word bits for the three-phase and single-phase modes. Note the following in these figures:

➤ 3P is appended for the three-phase mode (ESPB := N)

➤ A, B, C are appended for the single-phase mode (ESPB := Y)

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Close and Reclose Logic   6.3
Breaker Status Logic

In the remaining figures and examples of this section, these appended characters are not always shown on the SELOGIC settings and Relay Word bits. For instance, 79RI is shown, rather than 79RI3P or 79RIA, 79RIB, 79RIC.

From *Figure 6.3* on, most of the figures demonstrate the three-pole mode. However, the logic is readily extrapolated and applicable to single-phase applications.

Breaker Status Logic

Table 6.1   Breaker Status Settings/Outputs

	Three-Phase Recloser (Global Setting BKTYP := 3)	Single-Phase Recloser (Global Setting BKTYP := 1)
SELOGIC Settings	52A_3P	52A_A, 52A_B, 52A_C
Relay Word Bits	52A3P	52AA, 52AB, 52AC

Figure 6.2 shows how settings:

➤ BKTYP: Breaker/recloser Trip Type (Global setting)

➤ ESPB: Enable Single-Phase Breaker/recloser settings (Group setting)

enable reclosing relays (and accompanying close logic—see *Figure 6.1*):

➤ Three separate reclosing relays enabled for single-phase reclosing

➤ One reclosing relay enabled for three-phase reclosing

and configure the required breaker status:

➤ Relay Word bits 52AA, 52AB, and 52AC for single-phase reclosing

➤ Relay Word bit 52A3P for three-phase reclosing

MULTI-RECLOSER INTERFACE
The breaker status settings in Table 2.7 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93. Also, Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface.

At the upper tier in *Figure 6.2*, the breaker/recloser type setting BKTYP makes the large demarcation for recloser type:

➤ BKTYP := **1** single-phase

➤ BKTYP := **3** three-phase

Note that even if a single-phase recloser (setting BKTYP := 1) is set for three-phase reclosing (setting ESPB := N), the single-phase breaker/recloser statuses (Relay Word bits 52AA, 52AB, and 52AC) are still available for monitoring. In this case, the one enabled reclosing relay (one reclosing relay to operate all three phases) uses the derived breaker status 52A3P.

Conversely, even if a single-phase recloser (setting BKTYP := 1) is set for single-phase reclosing (setting ESPB := Y), the three-phase breaker/recloser status (Relay Word bit 52A3P) is still available for monitoring. In this case, the three separate, enabled reclosing relays (one reclosing relay per phase) use respective breaker status 52AA, 52AB, and 52AC.

6.4 | Close and Reclose Logic
Breaker Status Logic

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Figure 6.2   Breaker Status Logic

Factory 52A Settings Example (Traditional Retrofit Recloser)

Figure 2.50 shows the monitored trip and close circuit points on Traditional Retrofit reclosers. Switch SW1 is the 52a auxiliary contact in the trip circuit. Relay Word bit SW1 is derived from the monitored trip circuit points (inputs IN203 and IN204) and trip output (controlled by Relay Word bit RCTR1X) status:

SW1 = logical 1 (switch SW1 [52a auxiliary contact] closed)
SW1 = logical 0 (switch SW1 [52a auxiliary contact] open)

SELOGIC setting 52A_3P includes the close output (Relay Word bit RCCL1X) to delay the change of state of Relay Word bit 52A3P until the unlatch close logic (see *Figure 6.5*) unlatches the close signal output CLOSE3P (see *Figure 6.3*):

52A_3P := **SW1 AND NOT RCCL1X**

This ensures that the 52b auxiliary in the close circuit is open (as indicated by input IN201, connected to the close circuit in *Figure 2.50*) before the close signal output is unlatched (CLOSE3P = logical 0). Close signal output CLOSE3P drives the actual close output RCCL1X via SELOGIC setting RCCL1 := CLOSE3P (see *Figure 7.26*).

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Factory 52A Settings Example (G&W Viper-ST Recloser)

Figure 2.54 shows the required breaker status wiring for the 52A_*x* (*x* = A, B, C) SEL<small>OGIC</small> settings.

    52A_A := **IN201**
    52A_B := **IN202**
    52A_C := **IN203**

Table 9.18 shows variations of the 52A_*x* (*x* = A, B, C) SEL<small>OGIC</small> settings for different IPCONN settings.

52A Used in Many Settings

The following factory-default SEL<small>OGIC</small> control equations settings use the resultant 52A Relay Word bit:

    79RIS3P := **52A3P OR 79CY3P** reclose initiate—see *Table 6.8* and following explanation

    PB11_LED := **52A3P…** RECLOSER CLOSED LED—see *Table 11.9*

    PB12_LED := **NOT 52A3P…** RECLOSER OPEN LED—see *Table 11.9*

    BSYNCH := **52A3P** block synchronism-check elements—see *Figure 4.30*

Close Logic

NOTE: Review Three-Phase (3P) vs. Single-Phase (A, B, and C) on page 6.2.

Table 6.2   Close Logic Settings/Outputs

	Three-Phase Closing (Factory-Default Setting ESPB := N)	Single-Phase Closing (Setting ESPB := Y)
Setting	CFD	CFD
SELOGIC Settings	CL3P	CLA, CLB, CLC
	ULCL3P	ULCLA, ULCLB, ULCLC
Relay Word Bits	CLOSE3P	CLOSEA, CLOSEB, CLOSEC
	CF3P	CFA, CFB, CFC

The close logic in *Figure 6.3* provides flexible circuit breaker closing/ automatic reclosing with SEL<small>OGIC</small> control equation settings:

    CL   (close conditions, other than automatic reclosing—also see *Figure 6.4*)

    ULCL   (unlatch close conditions, other than circuit breaker status, close failure, or reclose initiation—also see *Figure 6.5*)

and setting:

    CFD   (Close Failure Time)

6.6 | Close and Reclose Logic
Close Logic

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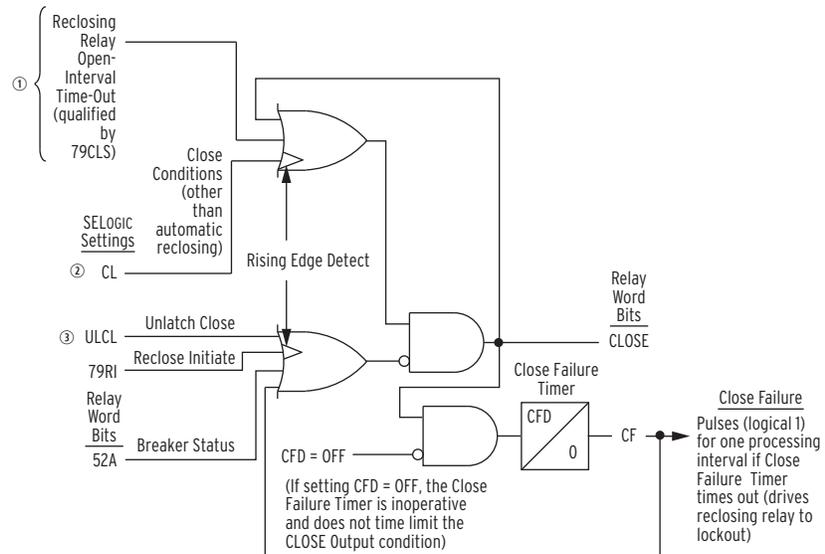
① From Figure 6.6; ② Example in Figure 6.4; see Table 6.2;
③ Example in Figure 6.5; see Table 6.2.

Figure 6.3   Close Logic

Set Close

In *Figure 6.3*, if *all* the following are true:

➤ The unlatch close condition is not asserted (ULCL = logical 0).

➤ The circuit breaker is open (52A = logical 0).

➤ The reclose initiation condition (79RI) is not making a rising edge (logical 0 to logical 1) transition.

➤ And a close failure condition does not exist (Relay Word bit CF = 0).

then the CLOSE Relay Word bit asserts to logical 1 if either of the following occurs:

➤ A reclosing relay open-interval times out (qualified by SELOGIC control equation setting 79CLS—see *Figure 6.6*).

➤ Or SELOGIC control equation setting CL goes from logical 0 to logical 1 (rising edge transition).

Unlatch Close

In *Figure 6.3*, if the CLOSE Relay Word bit is asserted at logical 1, it stays asserted at logical 1 until *one* of the following occurs:

➤ The unlatch close condition asserts (ULCL = logical 1).

➤ The circuit breaker closes (52A = logical 1).

➤ The reclose initiation condition (79RI) makes a rising edge (logical 0 to logical 1) transition.

➤ Or the Close Failure Timer times out (Relay Word bit CF = logical 1).

The Close Failure Timer is inoperative if setting CFD := OFF.

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Factory-Default CL/ULCL Settings Example

The factory-default settings for the three-phase (3P) close logic SELOGIC control equation settings are as follows:

CL3P := **(PB11_PUL AND LT05 OR CC3) AND LT06 AND TCCAP**

ULCL3P := **TRIP3P OR (NOT IN201 AND SW1) OR NOT(LT06 AND TCCAP OR CLOSE3P) OR NOT(LT05 OR CLOSE3P OR CC3 OR 79CY3P)**

[= **TRIP3P OR (NOT IN201 AND SW1) OR (NOT LT06 OR NOT TCCAP) AND NOT(CLOSE3P) OR NOT(LT05) AND NOT(CLOSE3P) AND NOT(CC3) AND NOT(79CYC3P)**]

The (NOT IN201 and SW1) logic term in the above ULCL3P factory setting is just for Traditional Retrofit recloser applications—it is not present in factory settings for the other recloser applications.

The factory-default setting for the Close Failure Timer setting is:

CFD := **60.00 cycles**

Set Close

If the Reclosing Relay Open-Interval Time-Out logic input at the top of *Figure 6.3* is ignored (reclosing is discussed in detail in a following subsection), then SELOGIC control equation setting CL is the only logic input that can set the CLOSE Relay Word bit.

In SELOGIC control equation setting CL (see *Figure 6.4*), closing is provided by:

➤ **CLOSE** operator control (local)

➤ Serial port **CLOSE** command (remote)

Supervision of these local and remote close signals is provided by:

➤ **PUSHBUTTONS LOCKED** operator control—supervises **CLOSE** operator control

➤ **HOT LINE TAG** operator control and TCCAP Relay Word bit—supervise both the **CLOSE** operator control and the serial port **CLOSE** command

Other details:

➤ The **PUSHBUTTONS LOCKED** operator control also supervises other front-panel operator controls (see *Table 11.9*).

➤ The **HOT LINE TAG** operator control also supervises automatic reclosing (see *Table 11.9*).

➤ No "standing close" is possible with the close logic in *Figure 6.4*. The **CLOSE** operator control (Relay Word bit PB11_PUL) and serial port **CLOSE** command (Relay Word bit CC3) pulse for only one processing interval (one quarter cycle) when activated.

Also, in *Figure 6.3*, SELOGIC control equation setting CL is rising-edge triggered. Thus, if the **PUSHBUTTONS LOCKED** operator control (Relay Word bit LT05) or the **HOT LINE TAG** operator control (Relay Word bit LT06) in *Figure 6.4* are turned ON or OFF, no unexpected close takes place, because there is no standing close condition waiting to get through.

6.8 | Close and Reclose Logic
Close Logic

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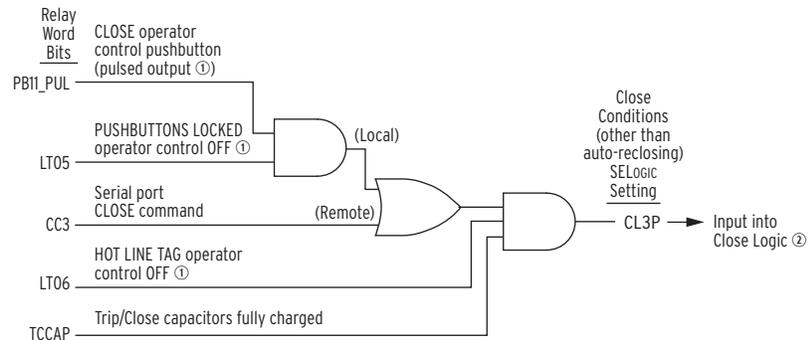
① See Table 11.9, ② See Table 6.3.

Figure 6.4   Close Conditions–Other Than Automatic Reclosing (Three-Phase, Factory Default)

Unlatch Close

Figure 6.5 shows the additional means to unlatch the close logic, besides those embedded in *Figure 6.3*. The TRIP3P Relay Word bit in setting ULCL3P keeps the TRIP3P and CLOSE3P Relay Word bits from being asserted at the same time—TRIP3P has priority.

The logic in the upper part of *Figure 6.5* is as follows:

ULCL3P := **... OR (NOT IN201 AND SW1) OR ...**

This logic delays unlatching of the close output signal (Relay Word bit CLOSE) in *Figure 6.3* until both auxiliary contacts SW1 (52a) and SW3 (52b) change state for the close operation (see *Figure 2.50*). Logic term (NOT IN201 and SW1) applies only to traditional retrofit reclosers.

The logic in the lower part of *Figure 6.5* is as follows:

ULCL3P := **... OR (NOT LT06 OR NOT TCCAP) AND NOT(CLOSE3P) OR NOT(LT05) AND NOT(CLOSE3P) AND NOT(CC3) AND NOT(79CYC3P)**

This logic is security against unwanted close initiations. The **HOT LINE TAG** operator control and trip/close capacitor monitor are preeminent; if there is no close in progress **and HOT LINE TAG** is on or the trip/close capacitors are not fully charged, no new closing can be initiated. The **PUSHBUTTONS LOCKED** operator control is less restrictive; serial port **CLOSE** commands and automatic reclosing are not affected by it. But, in *Figure 6.4*, the **CLOSE** operator control is still supervised by the **PUSHBUTTONS LOCKED** operator control.

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Close Logic
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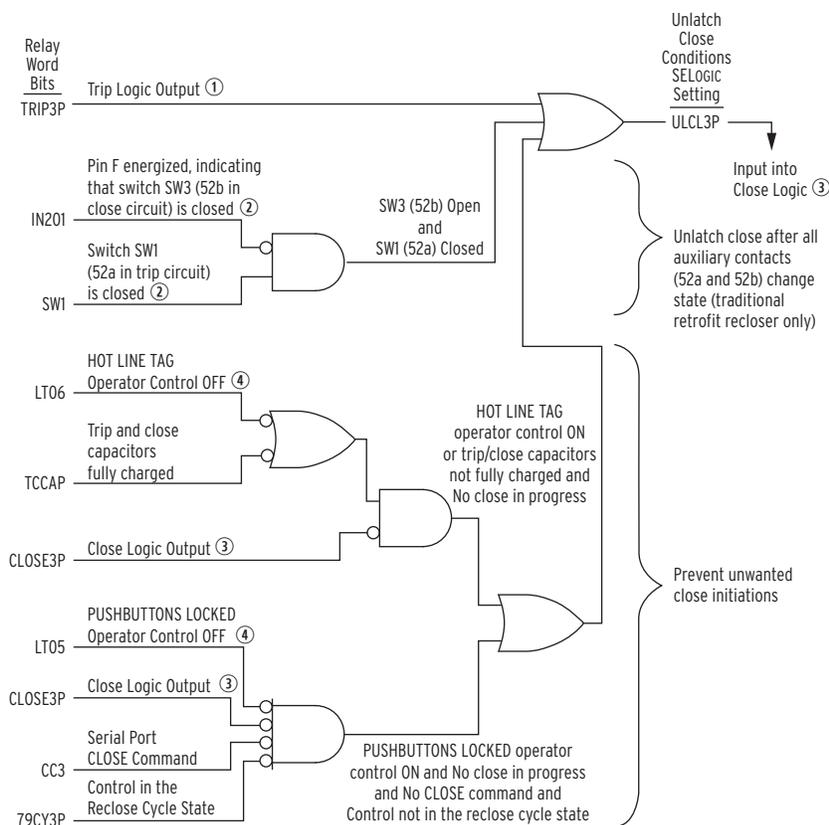
① See Figure 5.1, ② See Figure 2.50, ③ See Figure 6.3, ④ See Table 11.9.

Figure 6.5   Unlatch Close Conditions (Three-Phase, Factory Default)

Close Failure

With setting CFD := 60.00 cycles, once the CLOSE Relay Word bit asserts in *Figure 6.3*, it remains asserted at logical 1 no longer than a *maximum* of 60 cycles. If the Close Failure Timer times out, Relay Word bit CF asserts to logical 1, forcing the CLOSE Relay Word bit to logical 0.

Defeat the Close Logic

Defeat the close logic and reclosing relay logic by setting the corresponding SELOGIC breaker auxiliary settings (52A_) directly to logical 0 (see *Figure 6.2*):

➤ For three-phase reclosers or single-phase reclosers operating in a three-phase mode (Group setting ESPB := N; one reclosing relay available: one for all three phases), set 52A_3P directly to logical 0 (52A_3P := 0).

➤ For single-phase reclosers operating in a single-phase mode (Group setting ESPB := Y; three separate reclosing relays available: one for each phase), set at least one of 52A_A, 52A_B, or 52A_C directly to logical 0 (e.g., 52A_B := 0).

Having one or more SELOGIC breaker auxiliary settings set directly to logical 0 (e.g., 52A_B := 0) defeats the close logic and reclosing relay logic for all three phases.

6.10 | Close and Reclose Logic
Reclose Supervision Logic

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Program an Output Contact for Closing

See *Trip and Close Mapping and Output Logic on page 7.31* for more information on programming outputs for closing the recloser. Relay Word bits CLOSE3P, CLOSEA, CLOSEB, and CLOSEC from *Figure 6.1* are used to program close outputs.

Reclose Supervision Logic

NOTE: Review Three-Phase (3P) vs. Single-Phase (A, B, and C) on page 6.2.

Table 6.3   Reclose Supervision Settings/Outputs

	Three-Phase Reclosing (Factory-Default Setting ESPB := N)	Single-Phase Reclosing (Setting ESPB := Y)
Setting	79CLSD	79CLSD
SELOGIC Settings	79CLS3P	79CLSA, 79CLSB, 79CLSC
Relay Word Bits	RCSF3P	RCSFA, RCSFB, RCSFC

One of the inputs into the close logic in *Figure 6.3* is:

Reclosing Relay Open-interval Time-Out (qualified by 79CLS)

This input is the indication that a reclosing relay open interval has timed out (see *Figure 6.10*) and a qualifying condition (SELOGIC control equation setting 79CLS) has been met, and thus automatic reclosing of the circuit breaker should proceed by asserting the CLOSE Relay Word bit to logical 1. This input into the close logic in *Figure 6.3* is an output of the reclose supervision logic in the following *Figure 6.6*.

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Close and Reclose Logic 6.11
Reclose Supervision Logic
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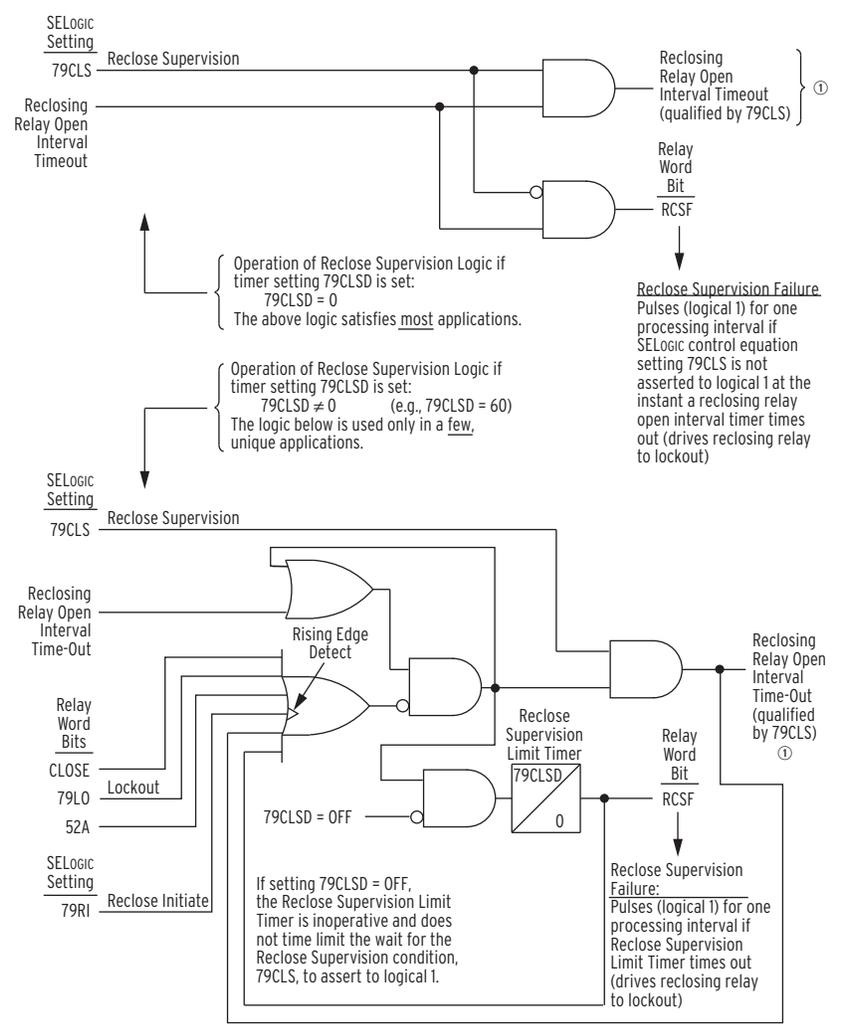
① See Figure 6.3.

Figure 6.6   Reclose Supervision Logic (Following Open‑Interval Time‑Out)

6.12 | Close and Reclose Logic
Reclose Supervision Logic

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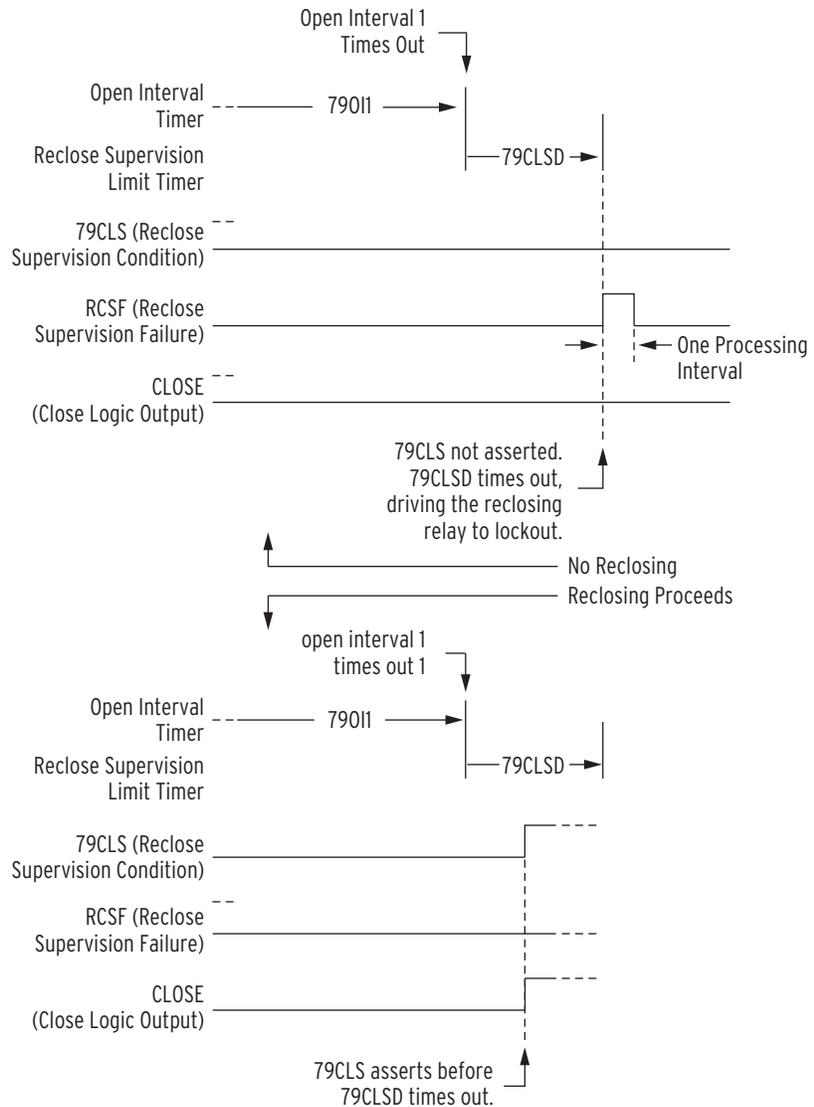
Figure 6.7 Reclose Supervision Limit Timer Operation (Refer to Bottom of Figure 6.6)

Settings and General Operation

Figure 6.6 contains the following SELOGIC control equation setting:

> 79CLS (reclose supervision conditions—checked after reclosing relay open-interval time-out)

and setting:

> 79CLSD (Reclose Supervision Limit Time)

See *Reclosing Relay on page SET.29* for setting ranges.

For Most Applications (Top of Figure 6.6)

For most applications, the Reclose Supervision Limit Time setting should be set to zero cycles:

> 79CLSD := **0.00**

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With this setting, the logic in the top of *Figure 6.6* is operative. When an open interval times out, the SELOGIC control equation reclose supervision setting 79CLS is *checked just once*.

If 79CLS is *asserted* to logical 1 at the instant of an open-interval time-out, then the now-qualified open-interval time-out will propagate onto the final close logic in *Figure 6.3* to automatically reclose the circuit breaker.

If 79CLS is *deasserted* to logical 0 at the instant of an open-interval time-out:

> ➤ No automatic reclosing takes place.

> ➤ Relay Word bit RCSF (Reclose Supervision Failure indication) asserts to logical 1 for one processing interval.

> ➤ The reclosing relay is driven to the Lockout State.

See *Factory-Default 79CLS Settings Example* and *Additional 79CLS Settings Example 1* for details.

For a Few, Unique Applications (Bottom of Figure 6.6 and Figure 6.7)

For a few unique applications, the Reclose Supervision Limit Time setting is *not* set to zero cycles, for example:

79CLSD := **60.00**

With this setting, the logic in the bottom of *Figure 6.6* is operative. When an open-interval times out, the SELOGIC control equation reclose supervision setting 79CLS is then *checked for a time window* equal to setting 79CLSD.

If 79CLS *asserts* to logical 1 at any time during this 79CLSD time window, then the now-qualified open-interval time-out will propagate onto the final close logic in *Figure 6.3* to automatically reclose the circuit breaker.

If 79CLS remains *deasserted* to logical 0 during this entire 79CLSD time window, when the time window times out:

> ➤ No automatic reclosing takes place.

> ➤ Relay Word bit RCSF (Reclose Supervision Failure indication) asserts to logical 1 for one processing interval.

> ➤ The reclosing relay is driven to the Lockout State.

The logic in the bottom of *Figure 6.6* is explained in more detail in the following text.

Set Reclose Supervision Logic (Bottom of Figure 6.6)

Refer to the bottom of *Figure 6.6*. If *all* the following are true:

> ➤ The close logic output CLOSE (also see *Figure 6.3*) is *not* asserted (Relay Word bit CLOSE = logical 0).

> ➤ The reclosing relay is *not* in the Lockout State (Relay Word bit 79LO = logical 0).

> ➤ The circuit breaker is open (52A = logical 0).

> ➤ The reclose initiation condition (79RI) is *not* making a rising edge (logical 0 to logical 1) transition.

> ➤ The Reclose Supervision Limit Timer is *not* timed out (Relay Word bit RCSF = logical 0).

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Reclose Supervision Logic

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then a reclosing relay open-interval time-out seals in *Figure 6.6*. This allows any assertion of 79CLS to propagate through *Figure 6.6* and on to the close logic in *Figure 6.3*.

Unlatch Reclose Supervision Logic (Bottom of Figure 6.6)

Refer to the bottom of *Figure 6.6*. If the reclosing relay open-interval time-out condition is sealed-in, it stays sealed-in until *one* of the following occurs:

➤ The close logic output CLOSE (also see *Figure 6.3*) asserts (Relay Word bit CLOSE = logical 1).

➤ The reclosing relay goes to the Lockout State (Relay Word bit 79LO = logical 1).

➤ The circuit breaker closes (52A = logical 1).

➤ The reclose initiation condition (79RI) makes a rising edge (logical 0 to logical 1) transition.

➤ SELOGIC control equation setting 79CLS asserts (79CLS = logical 1).

➤ Or the Reclose Supervision Limit Timer times out (Relay Word bit RCSF = logical 1 for one processing interval).

⚠ WARNING

Setting 79CLSD = OFF can create an indefinite "standing close" condition. This is usually not desirable in practice.

The Reclose Supervision Limit Timer is inoperative if setting 79CLSD := OFF. With 79CLSD := OFF, reclose supervision condition 79CLS is not time limited. When an open-interval times out, reclose supervision condition 79CLS is checked indefinitely until one of the other above unlatch conditions comes true.

The unlatching of the sealed-in reclosing relay open-interval time-out condition by the assertion of SELOGIC control equation setting 79CLS indicates successful propagation of a reclosing relay open-interval time-out condition on to the close logic in *Figure 6.3*.

See *Additional 79CLS Settings Example 2* for more information.

Factory-Default 79CLS Settings Example

Refer to the top of *Figure 6.6*.

The factory-default settings for the SELOGIC reclose supervision setting are as follows:

For controls ordered with an ac power supply:

79CLS3P := **PWR_SRC1 AND TCCAP AND NOT (BTFAIL)** Traditional Retrofit recloser

79CLS3P := **TCCAP AND NOT (BTFAIL)** all others

For controls ordered with a dc power supply:

79CLS3P := **PWR_SRC1 AND TCCAP** Traditional Retrofit recloser

79CLS3P := **TCCAP** all others

Relay Word bit PWR_SRC1 indicates the presence of power to the control. Power to the control, such as 120 Vac power, is used by the Traditional Retrofit reclosers to provide the final close energy. If this power is not present for these reclosers, there is no need to proceed with the reclosure.

Relay Word bit TCCAP indicates that the trip and close capacitors have sufficient stored energy for trips/reclosures. The monitoring point for TCCAP incorporates the capacitor charger, the capacitors themselves, and the connection from the capacitors to the relay module (J205 in *Figure 2.5*,

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Figure 2.8, and *Figure 2.9*). Relay Word bit TCCAP will deassert for a failure of any one of these elements. TCCAP may also momentarily deassert as a result of successive recloser operations drawing down the capacitor voltage. BTFAIL indicates some failure related to the battery or battery system. Controls ordered with a dc power supply do not have a battery, therefore BTFAIL is removed from the default 79CLS3P setting.

The factory-default setting for the reclose supervision time limit setting is as follows:

79CLSD := **900.00 cycles**

Within this 900-cycle time window, following the open-interval time (see *Figure 6.7*), if SELOGIC reclose supervision setting 79CLS3P effectively asserts to logical 1, then reclosing proceeds. Otherwise, if the reclose supervision time limit setting 79CLSD times out before SELOGIC reclose supervision setting 79CLS3P effectively asserts to logical 1, then no reclosure occurs and the reclosing relay is driven to lockout. If the 79CLS setting contains Relay Word bit TCCAP, setting 79CLSD should be set to at least a few seconds. This is to provide time for the capacitor voltage to recharge after successive recloser operations.

Additional 79CLS Settings Example 1

Refer to the top of *Figure 6.6* and *Figure 6.8*.

SEL-651R-2 controls are installed at both ends of a transmission line in a high-speed reclose scheme. After both circuit breakers open for a transmission line fault, the SEL-651R-2(1) recloses circuit breaker 52/1 first, followed by the SEL-651R-2(2) reclosing circuit breaker 52/2, after a synchronism check across circuit breaker 52/2.
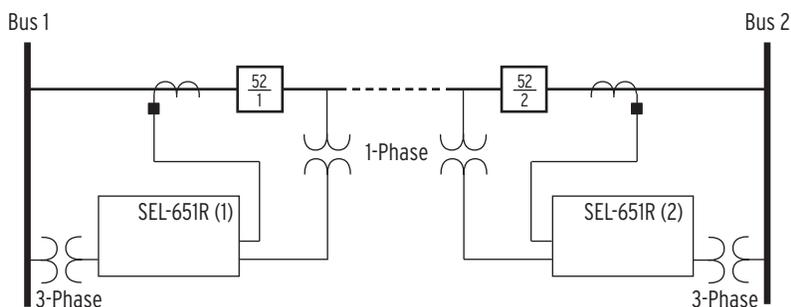
Figure 6.8 SEL-651R-2 Recloser Controls Installed at Both Ends of a Transmission Line in a High-Speed Reclose Scheme

SEL-651R-2(1)

Before allowing circuit breaker 52/1 to be reclosed after an open-interval time-out, the SEL-651R-2(1) checks if Bus 1 voltage is hot and the transmission line voltage is dead. This requires reclose supervision settings:

79CLSD := **0.00 cycles** (only one check)

79CLS3P := **3P59Y AND 27ZA1 AND TCCAP AND NOT (BTFAIL)**

where:

    3P59Y = all three Bus 1 phase voltages are hot
    27ZA1 = monitored single-phase transmission line voltage is dead

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where:

TCCAP = trip and close capacitors have sufficient stored energy for trips/reclosures

NOT (BTFAIL) = no failure related to the battery or battery system

SEL-651R-2(2)

Before allowing circuit breaker 52/2 to be reclosed after the reclosing relay open interval times out, the SEL-651R-2(2) checks if Bus 2 voltage is hot, the transmission line voltage is hot, and both are in synchronism. This requires reclose supervision settings:

79CLSD := **0.00 cycles** (only one check)

79CLS3P := **25A1 AND TCCAP AND NOT (BTFAIL)**

where:

25A1 = selected Bus 2 phase voltage is in synchronism with monitored single-phase transmission line voltage and both are hot

Other Setting Considerations for SEL-651R-2(1) and SEL-651R-2(2)

Refer to *Skip-Shot and Stall Open-Interval Timing Settings (79SKP and 79STL, Respectively)*.

SELOGIC control equation setting 79STL stalls open-interval timing if it asserts to logical 1. If setting 79STL is deasserted to logical 0, open-interval timing can continue.

The SEL-651R-2(1) has no intentional open-interval timing stall condition (circuit breaker 52/1 closes first after a transmission line fault):

79STL := **0** (set directly to logical 0)

The SEL-651R-2(2) starts open-interval timing after circuit breaker 52/1 at the remote end has re-energized the line. The SEL-651R-2(2) has to see that Bus 2 voltage is hot, transmission line voltage is hot, and that these voltages are synchronized across open circuit breaker 52/2 for open-interval timing to begin. Thus, SEL-651R-2(2) open-interval timing is stalled when the transmission line voltage and Bus 2 voltage are *not* in synchronism across open circuit breaker 52/2:

79STL := **NOT 25A1 AND TCCAP AND NOT (BTFAIL)**

Note: A transient synchronism-check condition across open circuit breaker 52/2 could possibly occur if circuit breaker 52/1 recloses into a fault on one phase of the transmission line. The other two unfaulted phases would be briefly energized until circuit breaker 52/1 is tripped again. If the SEL-651R-2(2) is connected to one of these briefly energized phases, synchronism-check element 25A1 could momentarily assert to logical 1.

Ensure that the open-interval timers in the SEL-651R-2(2) are set to an appreciable time greater than the momentary energization time of the faulted transmission line to prevent the momentary assertion of synchronism-check element 25A1 from causing an inadvertent reclose of circuit breaker 52/2. Or, run the synchronism-check element 25A1 through a programmable timer before using it in the preceding 79CLS and 79STL settings for the SEL-651R-2(2). Note the built-in 3-cycle qualification of the synchronism-check voltages shown in *Figure 4.30*.

Additional 79CLS Settings Example 2

Refer to *Synchronism-Check Elements on page 4.38*. Also refer to *Figure 6.7* and *Figure 6.8*.

If the synchronizing voltages across open circuit breaker 52/2 are "slipping" with respect to one another, the Reclose Supervision Limit Timer setting 79CLSD should be set greater than zero so there is time for the slipping voltages to come into synchronism. For example:

79CLSD := **60.00 cycles**

79CLS3P := **25A1 AND TCCAP AND NOT (BTFAIL)**

The status of synchronism-check element 25A1 is checked continuously during the 60-cycle window. If the slipping voltages come into synchronism while timer 79CLSD is timing, synchronism-check element 25A1 asserts to logical 1 and reclosing proceeds.

In *Synchronism-Check Elements*, refer to *Synchronism-Check Element Outputs on page 4.48*, Voltages V_P and V_S are "Slipping and Setting TCLOSD ≠ 0.00." Item 3 describes a last attempt for a synchronism-check reclose before timer 79CLSD times out or setting 79CLSD := 0.00 and only one check is made.

Reclosing Relay

NOTE: Figure 6.1 shows one reclosing relay operative for three-phase reclosing (Group setting ESPB := N) and three separate reclosing relays operative for single-phase reclosing (Group setting ESPB := Y). Most of the examples in this reclosing relay subsection are three-phase reclosing examples, unless otherwise stated. These three-phase reclosing examples can be readily extrapolated to corresponding single-phase reclosing applications.

Table 6.4   Reclosing Relay Settings/Outputs (Sheet 1 of 2)

	Three-Phase Reclosing (Factory-Default Setting ESPB := N)	Single-Phase Reclosing (Setting ESPB := Y)
Settings	79OI1, 79OI2, 79OI3, 79OI4, 79RSD, 79RSLD	79OI1, 79OI2, 79OI3, 79OI4, 79RSD, 79RSLD
SELOGIC Settings	79RI3P	79RIA, 79RIB, 79RIC
	79RIS3P	79RISA, 79RISB, 79RISC
	79DTL3P	79DTL3P
	79DTL3X	79DTL3X
		79DTLA, 79DTLB, 79DTLC
	79DLS3P	79DLSA, 79DLSB, 79DLSC
	79SKP3P	79SKPA, 79SKPB, 79SKPC
	79STL3P	79STLA, 79STLB, 79STLC
	79BRS3P	79BRSA, 79BRSB, 79BRSC
	79SEQ3P	79SEQA, 79SEQB, 79SEQC
	79CLS3P	79CLSA, 79CLSB, 79CLSC
Relay Word Bits	OPTMN3P	OPTMNA, OPTMNB, OPTMNC
	RSTMN3P	RSTMNA, RSTMNB, RSTMNC
	79RS3P	79RSA, 79RSB, 79RSC
	79CY3P	79CYA, 79CYB, 79CYC
	79LO3P	79LOA, 79LOB, 79LOC
	SH03P	SH0A, SH0B, SH0C
	SH13P	SH1A, SH1B, SH1C
	SH23P	SH2A, SH2B, SH2C

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Reclosing Relay

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Table 6.4   Reclosing Relay Settings/Outputs (Sheet 2 of 2)

	Three-Phase Reclosing (Factory-Default Setting ESPB := N)	Single-Phase Reclosing (Setting ESPB := Y)
	SH33P	SH3A, SH3B, SH3C
	SH43P	SH4A, SH4B, SH4C
Analog Outputs	79SH3P	79SHA, 79SHB, 79SHC

Note that input:

Reclosing Relay Open-Interval Time-Out

in *Figure 6.6* is the logic input that is qualified by SELOGIC control equation setting 79CLS and then propagated on to the close logic in *Figure 6.3* to automatically reclose a circuit breaker. The explanation that follows in this reclosing relay subsection describes all the reclosing relay settings and logic that eventually result in this open-interval time-out logic output (see bottom of *Figure 6.10*), which becomes the logic input into *Figure 6.6*. Other aspects of the reclosing relay are also explained. As many as four (4) automatic reclosures (shots) are available.

Enable/Disable Reclosing

The reclose enable setting, E79, has setting choices N, 1, 2, 3, and 4. Setting choices 1–4 are the number of desired automatic reclosures, with corresponding open-interval time settings (see *Table 6.6* for details).

If *either* of the following reclosing relay settings is made:

➤ Reclose enable setting E79 := N

➤ Open-interval 1 time setting 79OI1 := OFF

then the reclosing relay is defeated and no automatic reclosing can occur. Open-interval time settings are explained in detail in *Open-Interval Timers*.

If the reclosing relay is defeated, the following also occur:

➤ All three reclosing relay state Relay Word bits (79RS, 79CY, and 79LO) are forced to logical 0 (see *Table 6.5*).

➤ All shot-counter Relay Word bits (SH0, SH1, SH2, SH3, and SH4) are forced to logical 0 (see *Table 6.7*).

➤ The analog output 79SH is set to –1 (see *Table 6.7*).

➤ The front-panel LEDs 79 RESET, 79 CYCLE, and 79 LOCKOUT are all extinguished.

Close Logic Can Still Operate When the Reclosing Relay Is Defeated

If the reclosing relay is defeated, the close logic (see *Figure 6.3*) can still operate if SELOGIC control equation circuit breaker status setting 52A__ is set to something other than logical 0. Making the setting 52A__ := 0 defeats the close logic *and* also defeats the reclosing relay (see *Defeat the Close Logic* for details).

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Reclosing Relay States and General Operation

Table 6.5   Relay Word Bit and Front-Panel Correspondence to Reclosing Relay States

Reclosing Relay State	Corresponding Relay Word Bit	Corresponding Front-Panel LED
Reset	79RS	79 RESET
Reclose Cycle	79CY	79 CYCLE
Lockout	79LO	79 LOCKOUT

The reclosing relay is in one, and only one, of these states (listed in *Table 6.5*) at any time. When in a given state, the corresponding Relay Word bit asserts to logical 1, thus causing the corresponding LED to illuminate. Automatic reclosing only takes place when the relay is in the Reclose Cycle State. *Table 5.3* provides more information about front-panel LED programming.

Figure 6.9 explains in general the different states of the reclosing relay and its operation.

Reset State
The circuit breaker has been closed for a qualifying reset time. The SEL-651R is ready to go through an automatic reclosing sequence in the reclose cycle state if the circuit breaker trips open and reclose initiation is successful.

Relay Word bit 79RS = logical 1
Front-panel 79 RESET LED illuminated

Maintained Lockout Condition

Unsuccessful Reclose Initiation

Other Lockout Conditions

Reset Timer Times Out

Reset Timer Times Out

Successful Reclose Initiation

Successful Reclose Initiation

Lockout State
All automatic reclosing attempts are unsuccessful, reclose initiation is unsuccessful, other lockout conditions occur, or the SEL-651R powers up. The relay returns to the reset state after the circuit breaker is closed, the reset timer times out, and there are no maintained lockout conditions.

Relay Word bit 79LO = logical 1
Front-panel 79 LOCKOUT LED illuminated

All Automatic Reclosing Attempts Unsuccessful

Unsuccessful Reclose Initiation

Other Lockout Conditions

Reclose Cycle State
The SEL-651R Relay automatically recloses the circuit breaker after each successful reclose initiation and corresponding set open interval time.

Relay Word bit 79CY = logical 1
Front-panel 79 CYCLE LED illuminated

Figure 6.9   Reclosing Relay States and General Operation

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Reclosing Relay

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Reclosing Relay Timer Settings

Table 6.6 shows the open-interval and reset timer factory-default settings.

Table 6.6   Reclosing Relay Timer Settings and Setting Ranges

Timer Setting (range)	Factory-Default Setting (in cycles)	Definition
79OI1 (OFF, 12.00–999999 cyc)	300.00	open-interval 1 time
79OI2 (OFF, 90.00–999999 cyc)	600.00	open-interval 2 time
79OI3 (OFF, 120.00–999999 cyc)	600.00	open-interval 3 time
79OI4 (OFF, 120.00–999999 cyc)	OFF	open-interval 4 time
79RSD (180.00–999999 cyc)	1800.00	reset time from reclose cycle state
79RSLD (0.00–999999 cyc)	600.00	reset time from lockout state

The operation of these timers is affected by SELOGIC control equation settings discussed later in this section.

Open-Interval Timers

The reclose enable setting, E79, determines the number of open-interval time settings that can be set. For example, if setting E79 := 3, the first three open-interval time settings in *Table 6.6*, are made available for setting (and 79OI4 is forced to OFF and hidden).

If an open-interval time is set to OFF, then that open-interval time is not operable *and* neither are the open-interval times that follow it.

In the factory-default settings in *Table 6.6*, the open-interval 4 time setting 79OI4 is the first open-interval time setting set to OFF:

79OI4 := **OFF**

Thus, open-interval time 79OI4 is not operable. But if the settings were:

79OI3 := **OFF**

79OI4 := **900.00 cycles** (set to some value other than OFF)

open-interval time 79OI4 would still be inoperative, because a preceding open-interval time is set to OFF (i.e., 79OI3 := OFF).

If open-interval 1 time setting, 79OI1, is set to OFF (79OI1 := OFF), no open-interval timing takes place and the reclosing relay is defeated.

The open-interval timers time consecutively; they do not have the same beginning time reference point. In the *Figure 6.10* example, open-interval 1 time setting, 79OI1 := 30, times first. If the subsequent first reclosure is not successful, then open-interval 2 time setting, 79OI2 := 600, starts timing. If the subsequent second reclosure is not successful, the relay goes to the Lockout State because 79OI3 := OFF (no third open interval and subsequently no third reclosure).

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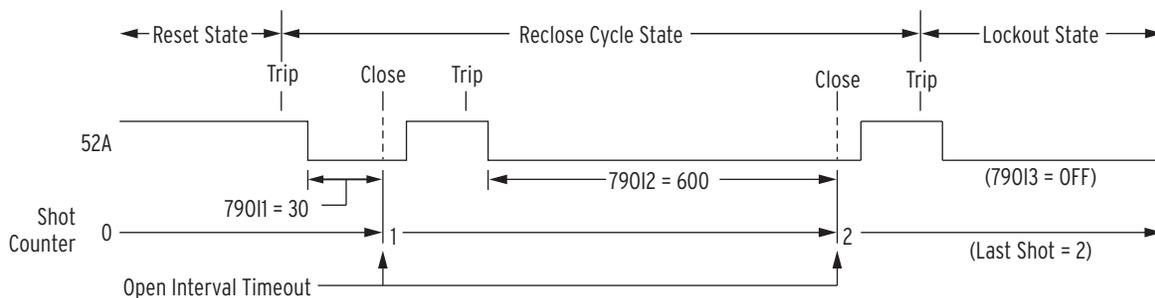
Figure 6.10 Example Reclosing Sequence From Reset to Lockout

SELOGIC control equation setting 79STL (stall open-interval timing) can be set to control open-interval timing.

Determination of Number of Reclosures (Last Shot)

The number of reclosures is equal to the number of open-interval time settings that precede the first open-interval time setting set to OFF. The "last shot" value is also equal to the number of reclosures.

In the *Figure 6.10* example, two set open-interval times precede open-interval 3 time, which is set to OFF (79OI3 := OFF):

> 79OI1 := **30.00**
>
> 79OI2 := **600.00**
>
> 79OI3 := **OFF**

For this example:

> Number of reclosures (last shot) = 2 = the number of set open-interval times that precede the first open-interval time set to OFF.

Observe Shot Counter Operation

Observe the reclosing relay shot counter operation, especially during testing, with the front-panel reclose count display (see *Table 11.2*).

Reset Timer

The reset timer qualifies circuit breaker closure before taking the relay to the Reset State from the Reclose Cycle State or the Lockout State. Circuit breaker status is determined by the SELOGIC control equation setting 52A.

Setting 79RSD:

> Qualifies closures when the relay is in the Reclose Cycle State. These closures are usually automatic reclosures resulting from open-interval time-out.
>
> Setting 79RSD is also the reset time used in sequence coordination schemes.

Setting 79RSLD:

> Qualifies closures when the relay is in the Lockout State. These closures are usually manual closures. These manual closures can originate externally to the relay, or via the SELOGIC control equation setting CL (see *Figure 6.3*).

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Setting 79RSLD is also the reset timer used when the relay powers up, when it has individual settings changed for the active settings group, or when the active settings group is changed.

See *Momentary Drive-to-Lockout While Breaker Closed* for a description of a scenario in which there is no reset timing via setting 79RSLD to go from the lockout state to the reset state. In this scenario, the drive-to-lockout setting 79DTL causes the relay to transition between the reset and lockout states, while the breaker remains closed continuously.

Typically, setting 79RSLD is set less than setting 79RSD. Such setting of 79RSLD emulates reclosing relays with motor-driven timers that have a relatively short reset time from the lockout position to the reset position. The 79RSD and 79RSLD settings are set independently. Setting 79RSLD can even be set greater than setting 79RSD, if desired. SELOGIC control equation setting 79BRS (block reset timing) can be set to control reset timing.

Monitoring Open-Interval and Reset Timing

Monitor open-interval and reset timing with the following Relay Word bits:

Relay Word Bits	Definition
OPTMN	Indicates that the open-interval timer is actively timing
RSTMN	Indicates that the reset timer is actively timing

If the open-interval timer is actively timing, OPTMN asserts to logical 1. When the relay is not timing on an open interval (e.g., it is in the Reset State or in the Lockout State), OPTMN deasserts to logical 0. The relay can only time on an open interval when it is in the Reclose Cycle State, but just because the relay is in the Reclose Cycle State does not necessarily mean the relay is timing on an open interval. The relay only times on an open interval after successful reclose initiation and if no stall conditions are present.

If the reset timer is actively timing, RSTMN asserts to logical 1. If the reset timer is not timing, RSTMN deasserts to logical 0.

Reclosing Relay Shot Counter

Refer to *Figure 6.10*.

The shot counter increments for each reclose operation. For example, when the relay is timing on open-interval 1, 79OI1, it is at shot = 0. When the open interval times out, the shot counter increments to shot = 1 and so forth for the set open intervals that follow. The shot counter cannot increment beyond the last shot for automatic reclosing. The shot counter resets back to shot = 0 when the reclosing relay returns to the Reset State.

Table 6.7   Shot Counter Correspondence to Relay Word Bits and Open-Interval Times

Shot	Corresponding Relay Word Bit	Corresponding Open-Interval	Analog Output
0	SH0	79OI1	79SH = 0
1	SH1	79OI2	79SH = 1
2	SH2	79OI3	79SH = 2
3	SH3	79OI4	79SH = 3
4	SH4		79SH = 4
reclosing relay defeated	N/A	N/A	79SH = −1

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When the shot counter is at a particular shot value (e.g., shot = 2), the corresponding Relay Word bit asserts to logical 1 (e.g., SH2 = logical 1).

The shot counter also increments for sequence coordination operation. The shot counter can increment beyond the last shot for sequence coordination, but only as high as shot = 4.

The analog output 79SH can be used in SELOGIC compares. For example, for a recloser operating in a three-phase mode (Group setting ESPB := N), the SELOGIC equation:

OUT202 := **79SH3P > 2**

would assert output contact OUT202 when the shot counter is at a value greater than 2.

Going to the Lockout State

The reclosing relay goes to the Lockout State if any *one* of the following occurs:

➤ The shot counter is equal to or greater than the last shot at time of reclose initiation. For example, all automatic reclosing attempts are unsuccessful (see *Figure 6.10*).

➤ Reclose initiation is unsuccessful because SELOGIC setting 79RIS (reclose initiation supervision) is effectively equal to logical 0.

➤ The circuit breaker opens without reclose initiation, such as happens with an external trip.

➤ The shot counter is equal to or greater than the last shot and the circuit breaker is open; for example, the shot counter is driven to last shot with SELOGIC control equation setting 79DLS while open-interval timing is in progress.

➤ The close failure timer (setting CFD) times out (see *Figure 6.3*).

➤ SELOGIC control equation setting 79DTL = logical 1.

➤ The Reclose Supervision Limit Timer (setting 79CLSD) times out (see *Figure 6.6* and top of *Figure 6.7*).

NOTE: Review Three-Phase (3P) vs. Single-Phase (A, B, and C) on page 6.2.

➤ A normal reclose initiation (e.g., SELOGIC control equation 79RI3P = TRIP3P) occurs and properly loads up an open-interval time (e.g., 79OI2 = 600 cycles; see *Figure 6.10*). Then, before the open-interval time has timed out completely (or even started timing), a subsequent unexpected reclose initiation occurs (e.g., flashover inside the circuit breaker tank while it is open).

Reclosing Relay States and Settings/Settings Group Changes

If individual settings are changed for the active settings group *or* the active settings group is changed, *all* of the following occur:

➤ The reclosing relay remains in the state it was in before the settings change.

➤ The shot counter is driven to last shot, with last shot corresponding to the new settings (see *Determination of Number of Reclosures (Last Shot)* for details on last shot).

➤ The reset timer is loaded with reset time setting 79RSLD (see *Reset Timer*).

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If the relay happened to be in the Reclose Cycle State and was timing on an open interval before the settings change, the relay would be in the Reclose Cycle State after the settings change, but the relay would immediately go to the Lockout State. This is because the breaker is open and the relay is at last shot after the settings change, so no more automatic reclosures are available.

If the circuit breaker remains closed through the settings change, the reset timer times out on reset time setting 79RSLD after the settings change and goes to the Reset State (if it is not already in the Reset State), and the shot counter returns to shot = 0. If the relay happens to trip during this reset timing, the relay will immediately go to the Lockout State, because shot = last shot.

Reclosing Relay SELOGIC Control Equation Settings Overview

NOTE: The SELOGIC settings in Table 6.8 have an appended "3P" (three-phase).

Table 6.8   Reclosing Relay SELOGIC Control Equation Settings

SELOGIC Control Equation Setting	Factory-Default Setting	Definition
79RI3P	TRIP3P	Reclose Initiate
79RIS3P	52A3P OR 79CY3P	Reclose Initiate Supervision
79DTL3P	(NOT LT02 OR NOT LT06) AND (TRIP3P OR NOT 52A3P) OR PB12_PUL OR OC3	Drive-to-Lockout
79DTL3X (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB Joslyn TriMod 600R, Siemens SDR Triple-Single, Eaton NOVA-TS or NOVA-STS Triple-Single)	R_TRIG SV02T	Drive-to-Lockout (extra)
79DTL3X (Multi-Recloser Interface)	R_TRIG SV02T AND (A1_CFG OR A3_CFG)	
79DTL3X (all others)	0	
79DLS3P	79LO3P	Drive-to-Last Shot
79SKP3P	(51PT OR 51G1T) AND NOT LT04 AND (79SH3P < MV01)	Skip Shot
79STL3P	TRIP3P	Stall Open-Interval Timing
79BRS3P	0	Block Reset Timing
79SEQ3P	0	Sequence Coordination
79CLS3P (Traditional Retrofit with ac power supply)	PWR_SRC1 AND TCCAP AND NOT (BTFAIL)	Reclose Supervision
79CLS3P (all others with ac power supply)	TCCAP AND NOT (BTFAIL)	
79CLS3P (Traditional Retrofit with dc power supply)	PWR_SRC1 AND TCCAP	
79CLS3P (all others with dc power supply)	TCCAP	

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The factory-default settings in *Table 6.8* are discussed in detail in the remainder of this section. They are for three-phase reclosing (factory-default setting ESPB := N).

Reclose Initiate and Reclose Initiate Supervision Settings (79RI and 79RIS, Respectively)

The reclose initiate setting 79RI is a rising-edge detect setting. The reclose initiate supervision setting 79RIS supervises setting 79RI. When setting 79RI detects a rising edge (logical 0 to logical 1 transition), setting 79RIS has to be at logical 1 (79RIS = logical 1) in order for open-interval timing to be initiated.

If 79RIS = logical 0 when setting 79RI detects a rising edge (logical 0 to logical 1 transition), the relay goes to the Lockout State.

Factory-Default 79RI/79RIS Settings Example

With factory-default settings:

79RI3P := **TRIP3P**

79RIS3P := **52A3P OR 79CY3P**

the transition of the TRIP3P Relay Word bit from logical 0 to logical 1 initiates open-interval timing only if the 52A3P or 79CY3P Relay Word bit is at logical 1.

The circuit breaker has to be closed (circuit breaker status 52A3P = logical 1) at the instant of the first trip of the automatic reclose cycle in order for the SEL-651R-2 to successfully initiate reclosing and start timing on the first open interval. The SEL-651R-2 is not yet in the reclose cycle state (79CY3P = logical 0) at the instant of the first trip.

Then for any subsequent trip operations in the automatic reclose cycle, the SEL-651R-2 is in the reclose cycle state (79CY3P = logical 1) and the SEL-651R-2 successfully initiates reclosing for each trip. Because of factory-default setting 79RIS3P := 52A3P OR 79CY3P, successful reclose initiation in the reclose cycle state (79CY3P = logical 1) is not dependent on the circuit breaker status (52A3P). This allows successful reclose initiation in the case of an instantaneous trip, but the circuit breaker status indication is slow: the instantaneous trip (reclose initiation) occurs before the SEL-651R-2 sees the circuit breaker close.

If a flashover occurs in a circuit breaker tank during an open interval (circuit breaker open) and the SEL-651R-2 calls for a trip, the SEL-651R-2 goes immediately to lockout.

Additional 79RI/79RIS Settings Example

The preceding settings example initiates open-interval timing on the rising edge of the TRIP3P Relay Word bit. The following is an example of reclose initiation on the opening of the circuit breaker.

With setting:

79RI3P := **NOT 52A3P**

the transition of the 52A3P Relay Word bit from logical 1 to logical 0 (breaker opening) initiates open-interval timing. Setting 79RI3P looks for a logical 0 to logical 1 transition, thus Relay Word bit 52A3P is inverted in the 79RI3P setting.

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The reclose-initiate supervision setting 79RIS3P supervises setting 79RI3P. With settings:

79RI3P := **NOT 52A3P**

79RIS3P := **TRIP3P**

the transition of the 52A3P Relay Word bit from logical 1 to logical 0 initiates open-interval timing only if the TRIP3P Relay Word bit is at logical 1 (TRIP3P = logical 1). Thus, the TRIP3P Relay Word bit has to be asserted when the circuit breaker opens to initiate open-interval timing. With a long enough setting of the Minimum Trip Duration Timer (TDURD), the TRIP3P Relay Word bit will still be asserted to logical 1 when the circuit breaker opens (see *Figure 5.1* and *Figure 5.4*).

If the TRIP3P Relay Word bit is at logical 0 (TRIP3P = logical 0) when the circuit breaker opens (logical 1 to logical 0 transition), the relay goes to the Lockout State. This helps prevent reclose initiation for circuit breaker openings caused by trips external to the relay.

Other 79RI/79RIS Settings Considerations

1. If no reclose initiate supervision is desired, make the following setting:

   79RIS := **1** set directly to logical 1

   Setting 79RIS = logical 1 at all times. Any time a logical 0 to logical 1 transition is detected by setting 79RI, open-interval timing will be initiated, unless prevented by other means.

2. If the following setting is made:

   79RI := **0** set directly to logical 0

   reclosing is never initiated. The reclosing relay is effectively inoperative.

3. If the following setting is made:

   79RIS := **0** set directly to logical 0

   the reclosing relay goes directly to the lockout state any time reclosing is initiated. The reclosing relay is effectively inoperative.

Drive-to-Lockout and Drive-to-Last-Shot Settings (79DTL and 79DLS, Respectively)

When 79DTL = logical 1, the reclosing relay goes to the Lockout State (Relay Word bit 79LO = logical 1) and the front-panel **LOCKOUT** LED illuminates.

79DTL has a 60-cycle dropout time. This keeps the drive-to-lockout condition up 60 more cycles after 79DTL has reverted back to 79DTL = logical 0. This is useful for situations where both of the following are true:

➤ Any of the trip and drive-to-lockout conditions are pulsed conditions (e.g., the **OPEN** Command Relay Word bit, OC3, asserts for only 1/4 cycle; refer to *Figure 6.11*).

➤ Reclose initiation is by the breaker contact opening (e.g., 79RI3P := NOT 52A3P; refer to *Additional 79RI/79RIS Settings Example* for details).

Then the drive-to-lockout condition overlaps reclose initiation and the SEL-651R-2 stays in lockout after the breaker trips open.

When 79DLS = logical 1, the reclosing relay goes to the last shot, if the shot counter is not at a shot value greater than or equal to the calculated last shot.

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Momentary Drive-to-Lockout While Breaker Closed

If the relay had previously been in the Reset State (Relay Word bit 79RS = logical 1) with the breaker closed and then a drive-to-lockout condition comes true (via setting 79DTL), the relay immediately goes to the Lockout State (Relay Word bit 79LO = logical 1). If the breaker continues to remain closed and then the drive-to-lockout condition (via setting 79DTL) goes away (after the previously discussed 60-cycle dropout time), the relay reverts immediately back to the Reset State.

No reset timing via setting 79RSLD is needed to return to the Reset State in this scenario because the breaker remains closed the entire time. The relay had previously timed on a reset time (setting 79RSD or 79RSLD) when it first went to the Reset State, before the drive-to-lockout logic (via setting 79DTL) started activating. Thus, there is no need to again reset-time-qualify a breaker that remained closed throughout such a transition (Reset State—Lockout State—Reset State), because of drive-to-lockout setting 79DTL.

Factory-Default 79DTL/79DLS Settings Example

The drive-to-lockout factory settings are as follows:

79DTL3P := **(NOT LT02 OR NOT LT06) AND (TRIP3P OR NOT 52A3P) OR PB12_PUL OR OC3**

79DTL3X := **R_TRIG SV02T** (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB Joslyn TriMod 600R, Siemens SDR Triple-Single, Eaton NOVA-TS or NOVA-STS Triple-Single)

79DTL3X := **R_TRIG SV02T AND (A1_CFG OR A3_CFG)** (Multi-Recloser Interface)

79DTL3X := **0** (all others)

Settings 79DTL3P and 79DTL3X are functionally equivalent, as evidenced in *Figure 6.1*. Setting 79DTL3X is for extra three-phase drive-to-lockout logic and is seen as a supplement to 79DTL3P. For the single-phase drive-to-lockout logic, settings 79DTL3P and 79DTL3X provide convenient locations to insert three-phase drive-to-lockout conditions (see *Figure 6.1*), rather than repetitively inserting them in each single-phase drive-to-lockout setting (79DTLA, 79DTLB, and 79DTLC).

Figure 6.11 shows in more detail the programmed conditions that drive the reclosing relay to lockout:

➤ If either the **RECLOSE ENABLED** operator control is OFF or the **HOT LINE TAG** operator control is ON **and** a trip occurs or the breaker opens, the reclosing relay is driven to lockout.

➤ If the **TRIP** operator control is pressed or an **OPEN** command is sent to the serial port, the reclosing relay is driven to lockout. Both these operations are deemed manual operations, thus no automatic reclosing takes place.

➤ The explanation for the 79DTL3X factory-default setting is found in the side column notes adjacent to *Figure 5.2* and *Figure 6.11*.

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"YELLOW OPERATING HANDLE" TRIP AND DRIVE-TO-LOCKOUT

The factory-default TR3X trip setting (Figure 5.2) and 79DTL3X drive-to-lockout setting (Figure 6.11) are set the same for G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield, Siemens SDR Triple-Single, Eaton NOVA-TS or NOVA-STS Triple-Single, and Multi-Recloser Interface reclosers. These settings propagate the pulling of a single yellow operating handle (on a single phase) to trip and lockout all three phases.

The ABB Joslyn TriMod 600R recloser does not need the TR3X "yellow operating handle" trip setting because the single yellow operating handle on the unit opens all three phases directly.
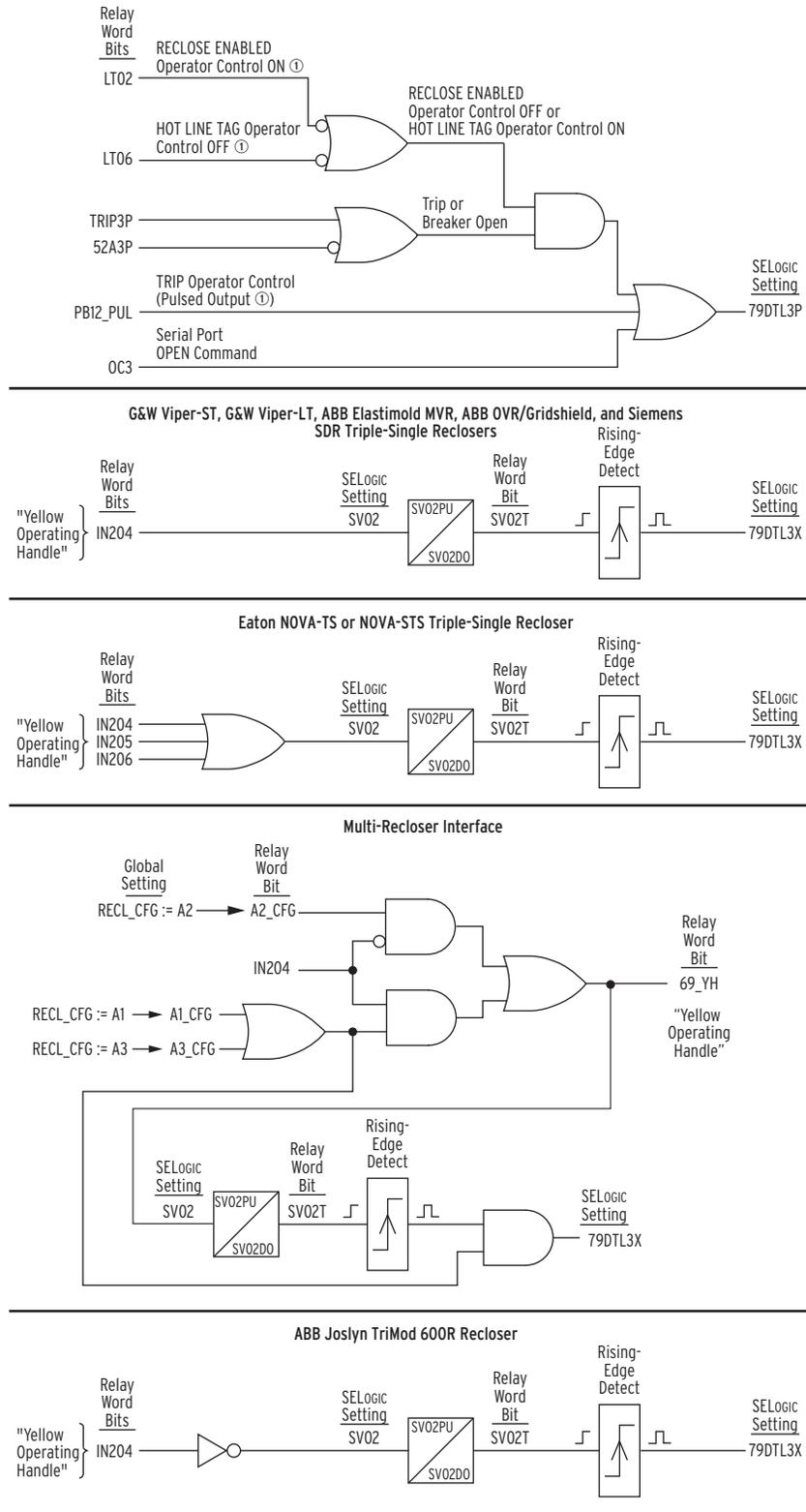
① See Table 11.9.

Figure 6.11   Factory-Default Drive-to-Lockout Logic Settings

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The drive-to-last-shot factory-default setting is:

> 79DLS3P := **79LO3P**

Three open-intervals are also set in the factory-default settings, resulting in last shot = 3. Any time the relay is in the lockout state (Relay Word bit 79LO3P = logical 1), the relay is driven to last shot if the shot counter is not already at a shot value greater than or equal to shot = 3:

> 79DLS3P := **79LO3P** = Logical 1

Additional 79DTL Settings Example

To drive the relay to the Lockout State for fault current above a certain level when tripping (e.g., level of phase instantaneous overcurrent element 50P3), make settings similar to the following:

> 79DTL3P := **TRIP3P AND 50P3 OR ...**

Additionally, if the reclosing relay should go to the Lockout State for an underfrequency trip, make settings similar to the following:

> 79DTL3X := **81D1T OR ...**

Other 79DTL/79DLS Settings Considerations

If no special drive-to-lockout or drive-to-last-shot conditions are desired, make the following settings:

> 79DTL := **0** set directly to logical 0
>
> 79DLS := **0** set directly to logical 0

With settings 79DTL and 79DLS inoperative, the relay still goes to the Lockout State and to last shot if an entire automatic reclose sequence is unsuccessful.

Overall, settings 79DTL or 79DLS are needed to take the relay to the Lockout State or to last shot for immediate circumstances.

Skip-Shot and Stall Open-Interval Timing Settings (79SKP and 79STL, Respectively)

The skip-shot setting 79SKP causes a reclose shot to be skipped. Thus, an open-interval time is skipped, and the next open-interval time is used instead.

If 79SKP = logical 1 at the instant of successful reclose initiation (see preceding discussion on settings 79RI and 79RIS), the relay increments the shot counter to the next shot and then loads the open-interval time corresponding to the new shot (see *Table 6.7*). If the new shot is the last shot, no open-interval timing takes place and the relay goes to the Lockout State if the circuit breaker is open.

After successful reclose initiation, open-interval timing does not start until allowed by the stall open-interval timing setting 79STL. If 79STL = logical 1, open-interval timing is stalled. If 79STL = logical 0, open-interval timing can proceed.

If an open-interval time has not yet started timing (79STL = logical 1 still), the 79SKP setting is still processed. In such conditions (open-interval timing has not yet started timing), if 79SKP = logical 1, the relay increments the shot counter to the next shot and then loads the open-interval time corresponding to the new shot (see *Table 6.7*).

If the open interval still does not start timing (it is still fully loaded for the given shot) and 79SKP is still asserted (79SKP = logical 1), then each subsequent processing interval (1/4 cycle), the shot counter will increment and

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the corresponding open-interval time will be loaded for that shot, superseding any previously loaded open intervals. With the preceding being true, the shot counter increments from shot = 0 to shot = 1 the first processing interval, from shot =1 to shot = 2 the second processing interval, and so forth until the last shot is reached.

If the new shot turns out to be the last shot, no open-interval timing takes place and the relay goes to the Lockout State if the circuit breaker is open (see *Going to the Lockout State*).

If the relay is in the middle of timing on an open interval and 79STL changes state to 79STL = logical 1, open-interval timing stops where it is. If 79STL changes state back to 79STL = logical 0, open-interval timing resumes where it left off. Use the OPTMN Relay Word bit to monitor open-interval timing (see *Monitoring Open-Interval and Reset Timing*).

Factory-Default 79SKP/79STL Settings Example

The skip-shot function factory-default setting is as follows:

79SKP3P := **(51PT OR 51G1T) AND NOT LT04 AND (79SH3P < MV01)**

MV01 := **2**

Refer to *Figure 6.12*. In a typical distribution protection scenario, there are two trips on fast curves, followed by two trips on delay curves. These operations can be phase (51PT) or ground (51G1T) time-overcurrent elements. How elements 51PT and 51G1T each convert between fast and delay curve operation is covered in *Time-Overcurrent Elements on page 4.13*.
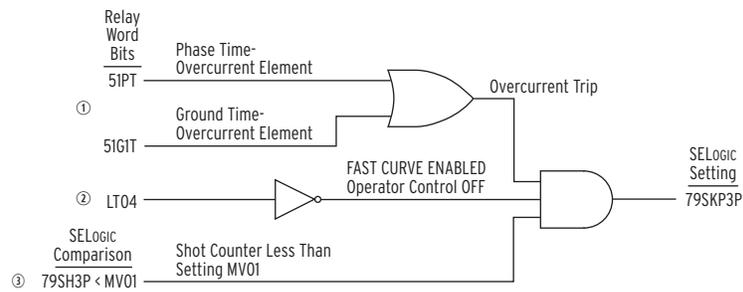
① See Figure 4.16 and Figure 4.22; ② Table 11.9; ③ Table 7.2.

Figure 6.12 Factory-Default Skip-Shot Logic

If the fast curves are disabled (**FAST CURVE ENABLED** operator control turned off; LT04 = logical 0), we do not want four delay-curve trips (two additional delay-curve trips replacing the two disabled fast-curve trips). We only want the two remaining delay-curve trips, with their standard open interval between them (open interval 3, setting 79OI3). The logic in *Figure 6.12* (dramatized in *Figure 6.13*) accelerates the sequencing of the shot counter so that the third open interval is loaded after the first trip on a delay curve.

As shown in the *Figure 6.10* example of a standard reclose sequence:

➤ The first trip occurs and shot = 0 (and first open-interval time is then loaded)

➤ and the second trip occurs and shot = 1 (and the second open-interval time is loaded)

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And it follows that the third open-interval (setting 79OI3) is loaded at the third trip, when shot = 2. So, to get the third open-interval loaded at the first trip rather than at the third trip, the shot counter has to be accelerated instantly from shot = 0 to shot = 2 (and then stop at shot = 2) at the time of the first trip. The comparison (79SH3P < MV01) at the bottom of *Figure 6.12* accomplishes this.

For *Figure 6.12*, math-variable setting MV01 is set to MV01 := 2, equal to the number of fast-curve trips. MV01 is compared to the reclosing relay shot counter, via analog output 79SH3P. Thus, if:

$$79SH3P < MV01 \; (= 2)$$

and the rest of the logic in *Figure 6.12* is true, then SELOGIC setting 79SKP3P effectively equals logical 1 (79SKP3P = logical 1). With 79SKP3P = logical 1, for the instant of the first trip, the shot counter increments from 79SH3P = 0 to 79SH3P = 1. The next processing interval (next quarter cycle), the overcurrent trip will still be on and the shot counter increments from 79SH3P = 1 to 79SH3P = 2. Now, the shot counter stops incrementing, because

$$79SH3P >= MV01 \; (= 2)$$

With the shot = 2, the third open-interval (setting 79OI3) is then loaded and timed, as shown in *Figure 6.13*. If the number of fast-curve trips is changed, math-variable setting MV01 is likewise changed.
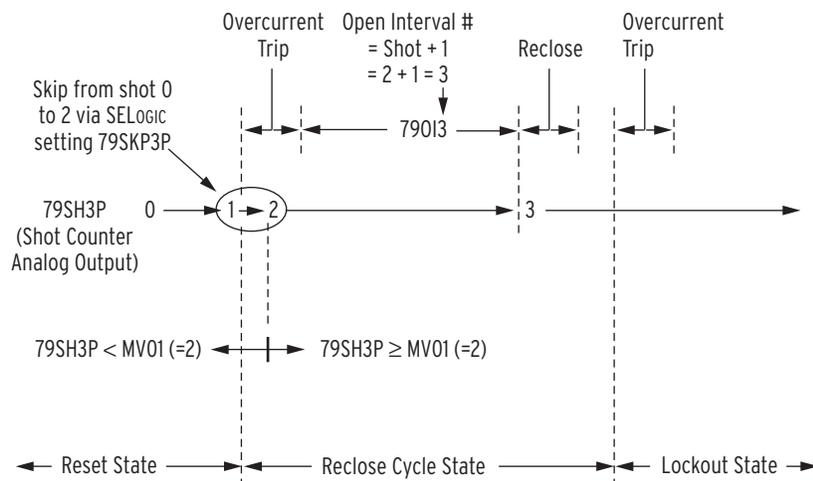
Figure 6.13   Skip-Shot Sequence

The stall open-interval timing factory setting is as follows:

79STL3P := **TRIP3P**

After successful reclose initiation, open-interval timing does not start as long as the trip condition is present (Relay Word bit TRIP3P = logical 1). As discussed previously, if an open-interval time has not yet started timing (79STL3P = logical 1 still), the 79SKP3P setting is still processed. Once the trip condition goes away (Relay Word bit TRIP3P = logical 0), open-interval timing can proceed.

OPEN INTERVAL TIMING STALLED TOO LONG?
If open interval timing is stalled too long by factory setting 79STL3P := TRIP3P, change the controlling minimum trip duration time setting TDURD. See Minimum Trip Duration Timer on page 5.7 for more detail.

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Additional 79SKP Settings Example

With skip-shot factory-set as follows,

79SKP3P := **50P2 AND SH03P**

if shot = 0 (Relay Word bit SH03P = logical 1) *and* phase current is above the phase instantaneous overcurrent element 50P2 threshold (Relay Word bit 50P2 = logical 1), at the instant of successful reclose initiation, the shot counter is incremented from shot = 0 to shot = 1. Then, open-interval 1 time (setting 79OI1) is skipped and the relay times on the open-interval 2 time (setting 79OI2) instead.

Table 6.9   Example Open-Interval Time Settings

Shot	Corresponding Relay Word Bit	Corresponding Open Interval	Open-Interval Time Setting
0	SH03P	79OI1	30 cycles
1	SH13P	79OI2	600 cycles

In *Table 6.9*, note that the open-interval 1 time (setting 79OI1) is a short time, while the following open-interval 2 time (setting 79OI2) is significantly longer. For a high-magnitude fault (greater than the phase instantaneous overcurrent element 50P2 threshold), open-interval 1 time is skipped and open-interval timing proceeds on the following open-interval 2 time. The longer open-interval time provides more time for the fault to dissipate (or the debris causing the fault to fall away from the line) and more equipment cooling time. Also, the skipped open interval reduces the number of potential reclosures back into the fault, thus reducing equipment stress.

Once the shot is incremented to shot = 1, Relay Word bit SH0 = logical 0 and then setting 79SKP3P = logical 0, regardless of Relay Word bit 50P2.

Additional 79STL Settings Example 1

If the SEL-651R-2 is used on a feeder with a line-side independent power producer (cogenerator), the utility should not reclose into a line still energized by an islanded generator. To monitor line voltage and block reclosing, connect a line-side single-phase potential transformer to a voltage channel on the SEL-651R-2 as shown in *Figure 6.14*.
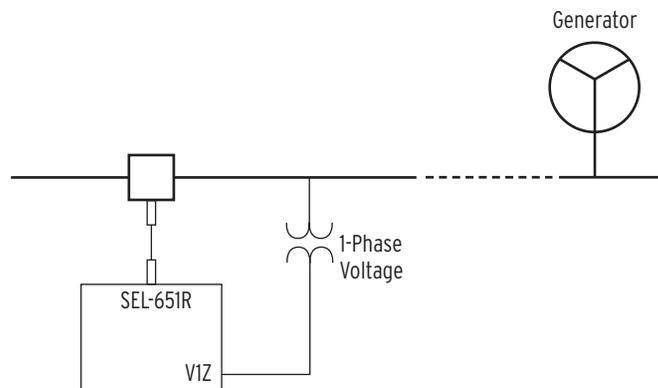
Figure 6.14   Reclose Blocking for Islanded Generator

If the line is energized, an overvoltage element can be set to assert. Make a setting like the following:

79STL3P := **59ZA1 OR ...**

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If line voltage is present, Relay Word bit 59ZA1 asserts, stalling open-interval timing (reclose block). If line voltage is not present, Relay Word bit 59ZA1 deasserts, allowing open-interval timing to proceed unless some other set condition stalls open-interval timing.

Additional 79STL Settings Example 2

Refer to *Figure 6.8* and the accompanying setting example, showing an application for setting 79STL.

Other 79SKP/79STL Settings Considerations

If no special skip-shot or stall open-interval timing conditions are desired, make the following settings:

79SKP := **0**   set directly to logical 0

79STL := **0**   set directly to logical 0

Block-Reset Timing Setting (79BRS)

The block-reset timing setting 79BRS keeps the reset timer from timing. Depending on the reclosing relay state, the reset timer can be loaded with either reset time:

79RSD (Reset Time from Reclose Cycle)

or

79RSLD (Reset Time from Lockout)

Depending on how setting 79BRS is set, none, one, or both of these reset times can be controlled. If the reset timer is timing and then 79BRS asserts to:

79BRS = logical 1

reset timing is stopped and does not begin timing again until 79BRS deasserts to:

79BRS = logical 0

When reset timing starts again, the reset timer is fully loaded. Thus, successful reset timing has to be continuous. Use the RSTMN Relay Word bit to monitor reset timing (see *Monitoring Open-Interval and Reset Timing*).

Factory-Default 79BRS Settings Example

The block reset function is not enabled in the factory settings:

79BRS3P := **0**   set directly to logical 0

Additional 79BRS Settings Example 1

The block reset timing setting is:

79BRS3P := **(51P OR 51G1) AND 79CY3P**

Relay Word bit 79CY3P corresponds to the Reclose Cycle State. The reclosing relay is in one of the three reclosing relay states at any one time (see *Figure 6.9* and *Table 6.5*).

When the relay is in the Reset or Lockout States, Relay Word bit 79CY3P is deasserted to logical 0. Thus, the 79BRS3P setting has no effect when the relay is in the Reset or Lockout States. When a circuit breaker is closed from lockout, there could be cold-load inrush current that momentarily picks up a time-overcurrent element (e.g., phase time-overcurrent element 51PT pickup

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[51P] asserts momentarily). But, this assertion of pickup 51P has no effect on reset timing because the relay is in the Lockout State (79CY3P = logical 0). The relay will time immediately on reset time 79RSLD and take the relay from the Lockout State to the Reset State with no additional delay because 79BRS3P is deasserted to logical 0.

When the relay is in the Reclose Cycle State, Relay Word bit 79CY3P is asserted to logical 1. Thus, the factory-default 79BRS3P setting can function to block reset timing if time-overcurrent pickup 51P or 51G1 is picked up while the relay is in the Reclose Cycle State. This helps prevent repetitive "trip-reclose" cycling.

Additional 79BRS Settings Example 2

If the block-reset timing setting is:

79BRS3P := **51P OR 51G1**

then reset timing is blocked if time-overcurrent pickup 51P or 51G1 is picked up, regardless of the reclosing relay state.

Sequence-Coordination Setting (79SEQ)

The sequence-coordination setting 79SEQ keeps the SEL-651R-2 in step with a downstream recloser in a sequence-coordination scheme. Sequence coordination prevents overreaching SEL-651R-2 overcurrent elements from tripping for faults beyond the downstream recloser. This is accomplished by incrementing the shot counter and supervising overcurrent elements with resultant shot-counter elements.

In order for sequence-coordination setting 79SEQ to increment the shot counter, both the following conditions must be true:

➤ No trip present (Relay Word bit TRIP = logical 0)

➤ Circuit breaker closed (SELOGIC control equation setting 52A = logical 1, effectively)

Sequence-coordination setting 79SEQ is usually set with some overcurrent element pickups. If the above two conditions are both true and a set overcurrent element pickup asserts for at least 1.25 cycles and then deasserts, the shot counter increments by one count. This assertion / deassertion indicates that a downstream device (e.g., downstream recloser—see *Figure 6.15*) has operated to clear a fault. Incrementing the shot counter keeps the SEL-651R-2 in step with the downstream device, as is shown in *Additional 79SEQ Settings Example 1* and *Additional 79SEQ Settings Example 2*.

Every time a sequence-coordination operation occurs, the shot counter is incremented and the reset timer is loaded up with reset time 79RSD. Sequence coordination can increment the shot counter beyond last shot, but no further than shot = 4. The shot counter returns to shot = 0 after the reset timer times out. Reset timing is subject to previously discussed SELOGIC control equation setting 79BRS.

Sequence-coordination operation does not change the reclosing relay state. For example, if the relay is in the Reset State and there is a sequence-coordination operation, it remains in the Reset State.

Factory-Default 79SEQ Settings Example

Sequence coordination is not enabled in the factory settings:

79SEQ3P := **0**

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Additional 79SEQ Settings Example 1

With sequence-coordination setting:

> 79SEQ3P := **79RS3P AND 51P**

sequence coordination is operable only when the SEL-651R-2 is in the Reset State (79RS3P = logical 1). Refer to *Figure 6.15* and *Figure 6.16*

NOTE: This example portrayed in Figure 6.15 and Figure 6.16 only shows operation with phase overcurrent elements. Sequence coordination can also work with ground overcurrent elements (e.g., add a ground time-overcurrent element pickup to the sequence-coordination setting: 79SEQ3P := 79RS3P AND (51P OR 51G1).

Assume that the downstream recloser is set to operate twice on the fast curve and then twice on the delay curve. The delay curve is allowed to operate after two fast-curve operations because the fast curves are then inoperative for tripping. The SEL-651R-2 fast curve is coordinated with the downstream recloser fast curve. The SEL-651R-2 delay curve is coordinated with the downstream recloser delay curve. How phase time-overcurrent element 51PT converts between fast and delay curve operation is covered in *Time-Overcurrent Elements on page 4.13*.
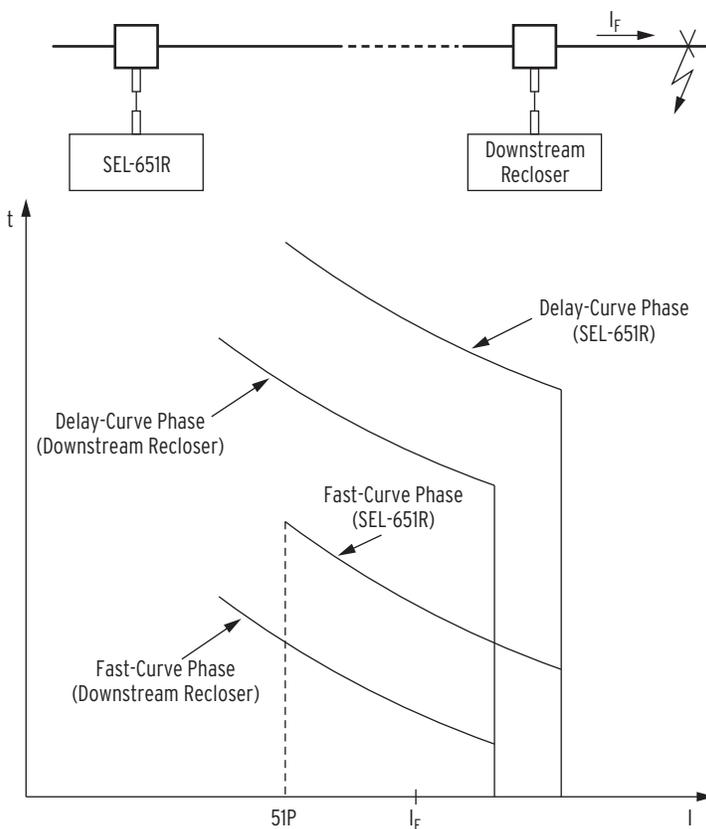
Figure 6.15   Sequence Coordination Between the SEL-651R-2 Recloser Control and a Downstream Recloser

① Fault occurs beyond downstream recloser.
② Fault cleared by downstream recloser fast curve.
③ Downstream recloser recloses into fault.
④ Fault cleared by downstream recloser delay curve.
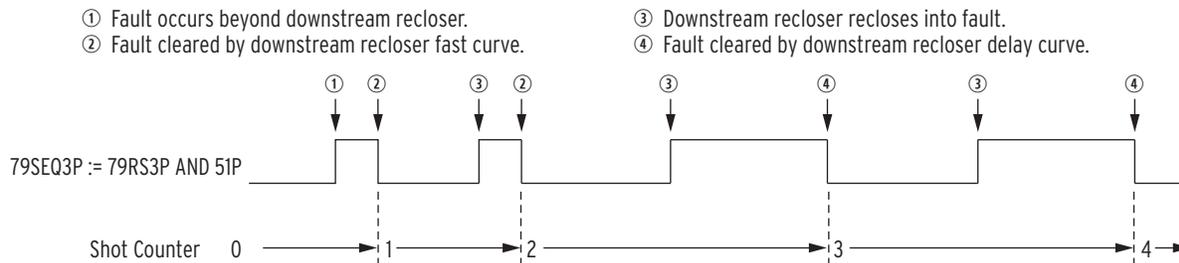
Figure 6.16   Operation of SEL-651R-2 Shot Counter for Sequence Coordination With Downstream Recloser (Additional 79SEQ Settings Example 1)

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If the SEL-651R-2 is in the Reset State (79RS3P = logical 1) and then a permanent fault beyond the downstream recloser occurs (fault current IF in *Figure 6.15*), the downstream recloser fast curve operates to clear the fault. The SEL-651R-2 also sees the fault. The phase time-overcurrent pickup 51P asserts and then deasserts without tripping, incrementing the SEL-651R-2 shot counter from:

shot = 0 to shot = 1

When the downstream recloser recloses, its fast curve operates again to clear the fault. The SEL-651R-2 also sees the fault again. The phase time-overcurrent pickup 51P asserts and then deasserts without tripping, incrementing the SEL-651R-2 shot counter from:

shot = 1 to shot = 2

At shot = 2, the SEL-651R-2 now operates on its delay curve, instead of its fast curve. This keeps the SEL-651R-2 in step with the downstream recloser, which now also operates on its delay curve, after two operations on its fast curve. If the fast curve was still active in the SEL-651R-2 for shot ≥ 2, it would overtrip for the fault beyond the downstream recloser (the SEL-651R-2 fast curve would operate before the downstream recloser delay curve).

Figure 6.16 shows the continuing operation of the sequence-coordination logic and subsequent incrementing of the shot counter to shot = 3 and shot = 4. The shot counter returns to shot = 0 after the reset timer (loaded with reset time 79RSD) times out.

Additional 79SEQ Settings Example 2

Review preceding Example 1.

The following example limits sequence-coordination shot-counter incrementing. Assume that the downstream recloser in *Figure 6.15* is set to operate twice on its fast curve and then twice on its delay curve for faults beyond it. Assume that the SEL-651R-2 is set to operate only once on its fast curve and then twice on its delay curve for faults between the SEL-651R-2 and the downstream recloser.

If the SEL-651R-2 sequence-coordination setting is:

79SEQ3P := **79RS3P AND 51P**

and there is a permanent fault beyond the downstream recloser, the shot counter of the SEL-651R-2 will increment all the way to shot = 4 (see *Figure 6.16*). If there is then a coincident fault between the SEL-651R-2 and the downstream recloser, the SEL-651R-2 will trip and go to the Lockout State. Any time the shot counter is at a value equal to or greater than last shot (last shot = 2, in this case) and the SEL-651R-2 trips, it goes to the Lockout State.

To avoid this problem, make the following sequence-coordination setting (refer to *Figure 6.17*):

79SEQ3P := **79RS3P AND 51P AND SH03P**

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① Fault occurs beyond downstream recloser.
② Fault cleared by downstream recloser fast curve.
③ Downstream recloser recloses into fault.
④ Fault cleared by downstream recloser delay curve.
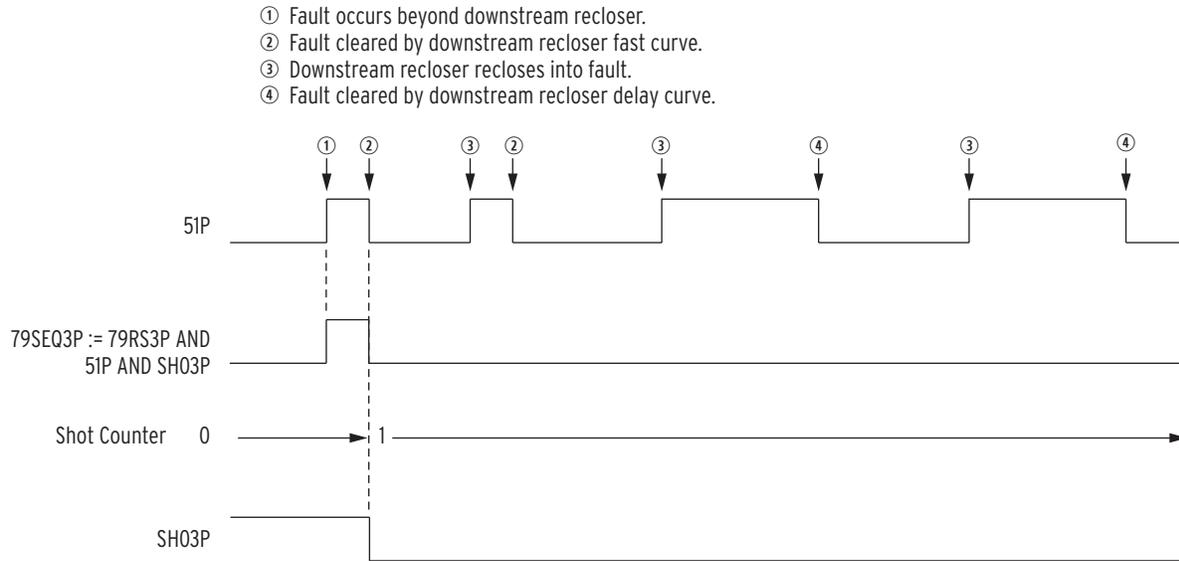
Figure 6.17 Operation of SEL-651R-2 Shot Counter for Sequence Coordination With Downstream Recloser (Additional 79SEQ Settings Example 2)

If the SEL-651R-2 is in the Reset State (79RS3P = logical 1) with the shot counter reset (shot = 0; SH03P = logical 1) and then a permanent fault beyond the downstream recloser occurs (fault current I_F in *Figure 6.15*), the downstream recloser fast curve operates to clear the fault. The SEL-651R-2 also sees the fault. The phase time-overcurrent pickup 51P asserts and then deasserts without tripping, incrementing the relay shot counter from:

shot = 0 to shot = 1

Now the SEL-651R-2 cannot operate on its fast curve because the shot counter is at shot = 1; it is now operating on its delay curve.

The downstream recloser continues to operate for the permanent fault beyond it, but the SEL-651R-2 shot counter does not continue to increment. Sequence-coordination setting 79SEQ3P is effectively disabled by the shot counter incrementing from shot = 0 (SH03P = logical 1) to shot = 1 (SH03P = logical 0).

79SEQ3P := **79RS3P AND 51P AND SH03P**

The shot counter stays at shot = 1.

Thus, if there is a coincident fault between the SEL-651R-2 and the downstream recloser, the SEL-651R-2 will operate on delay curve and then reclose once, instead of going straight to the Lockout State (shot = 1 < last shot = 2).

As stated earlier, the reset-time setting 79RSD takes the shot counter back to shot = 0 after a sequence-coordination operation increments the shot counter. Make sure that reset-time setting 79RSD is set long enough to maintain the shot counter at shot = 1 as shown in *Figure 6.17*.

Reclose Supervision Setting (79CLS)

See *Reclose Supervision Logic on page 6.10*.

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Section 7

SELOGIC Control Equation Programming

Functions use operands (inputs) and operators to generate outputs. Complex functions are created by using the outputs of several functions as operands in the new function.

Embedded relay functions such as protection elements, tripping and closing logic, and event report triggering use logic built into the SEL-651R-2. In some cases, these embedded functions can be customized because they include SELOGIC control equations as inputs. The outputs of these functions and equations are generally made available as Relay Word bits. Each function and equation is discussed in the appropriate protection, control, and monitoring section.

Custom functions may be constructed with SELOGIC control equations by using operands such as SELOGIC variables and embedded relay functions.

NOTE: All SELOGIC control equations must be set to NA, 0, 1, a single Relay Word bit, or a combination of Relay Word bits.

This section describes use of SELOGIC control equation programming to customize relay operation and automate substations. This section covers the following topics:

> ➤ SELOGIC control equation operands

> ➤ SELOGIC control equation operators

> ➤ SELOGIC control equation functions

SELOGIC Control Equation Capacity

SELOGIC control equation available capacity is a measure of remaining execution capacity and settings storage capacity. For maximum efficiency, use parentheses only when necessary and set unused equations to NA rather than 0 or 1.

Each SELOGIC control equation has a 15-operand maximum. Use a SELOGIC control equation variable (SV01–SV64) as an intermediate setting step if more operands are required.

Because the relay executes the logic at a deterministic interval, there is a limit to the amount of SELOGIC control equation programming that the relay can execute. Rather than limit parameters to guarantee that an application does not exceed the maximum processing requirements, the relay measures and calculates the available capacity when SELOGIC control equations are entered. The relay will not allow entry of programming that will cause the relay to be unable to complete all SELOGIC control equations each processing interval. The relay calculates capacities based on the total amount of SELOGIC control equation programming executed in Global, Group, Logic, and several other settings areas.

Use the **STATUS S** command to view available execution capacity and settings storage.

7.2 | SELOGIC Control Equation Programming
SELogic Control Equation Operands

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SELOGIC Control Equation Operands

Outputs from embedded relay functions are generally available for use as operands in SELOGIC control equations. Some analog values are available as operands as well. Use these operands to customize the operation of your SEL-651R-2 and use the SEL-651R-2 to automate substation operation. The operands available for use in SELOGIC control equations are summarized in *Table 7.1*.

Table 7.1   Summary of SELogic Control Equation Operands

Operand Type	Relay Word Bit Operands
Constants	0, 1
Inputs	Status Inputs, Optoisolated Inputs
Inputs	Local Bits (see *Section 11: Front-Panel Operations*)
Inputs	Remote Bits (see *Section 10: Communications*)
Inputs	Receive MIRRORED BITS (see *Appendix D: MIRRORED BITS Communications*)
Inputs	Virtual Bits (see *Appendix L: IEC 61850*)
Elements	Protection and Control Elements (see *Section 4: Protection Functions*)
Functions	Variables/Timers, Latch Bits, Counters
Outputs	Trip and Close Outputs, Contact Outputs
Outputs	Transmit MIRRORED BITS (see *Appendix D: MIRRORED BITS Communications*)
Analog	Received, Measured, or Calculated Analog Values

Relay Word Bits

Data within the relay are available for use in SELOGIC control equations. Relay Word bits include received digital values including optoisolated inputs, control bits, and remote bits. They also include calculated digital values such as SELOGIC control equation variables, SELOGIC control equation functions, and protection and control elements. *Appendix F: Relay Word Bits* contains a list of Relay Word bits available within the SEL-651R-2.

Analog Quantities

Analog quantities are analog values within the relay, including set, measured, and calculated values. *Table 7.2* contains a list of analog quantities available for SELOGIC expressions within the SEL-651R-2.

Table 7.2   Analog Quantities (Sheet 1 of 2)

NOTE: The analog quantities available for use in SELOGIC equations, as shown in Table 7.2, are a subset of the complete list of analog quantities shown in Table G.1.

Quantities	Description
PFA, PFB, PFC	Power factor magnitude; A-, B-, C-phase
PF3	Power factor, magnitude three-phase
LDPFA, LDPFB, LDPFC	Power factor leading = 1; A-, B-, C-phase
LDPF3	Power factor leading = 1; three-phase
IAHT, IBHT, ICHT	THD, Current, A-, B-, C-phase, magnitude
INHT	THD Current, neutral, magnitude
VAYHT, VBYHT, VCYHT	THD Voltage, A-, B-, C-phase-to-neutral, Y-terminals, magnitude

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Table 7.2   Analog Quantities (Sheet 2 of 2)

Quantities	Description
OPSCTRA, OPSCTRB, OPSCTRC	Total number of internal and external trips, A-, B-, C-phase, count
WEARA, WEARB, WEARC	Breaker contact wear, A-, B-, C-phase, percentage
MAXWEAR	Breaker contact wear, greatest value of A-, B-, C-phase, percentage
VAZHT, VBZHT, VCZHT	THD Voltage, A-, B-, C-phase-to-neutral, Z-terminals, magnitude
YEAR	Year number (0000–9999)
DAYY	Day of Year number (1–366)
WEEK[a]	Week number (1–53)
DAYW	Day of Week number (1–7)
MINSM	Minutes since Midnight
SC01–SC16	SELOGIC counter 01 to 16 present value (see *Analog Comparators and Checks on page 7.6* for more information)
MV01–MV64	Math Variable 01 to 64
79SHA, 79SHB, 79SHC	Shot counter—A-, B-, C-phase
79SH3P	Shot counter—three-phase
TCCAPV	Trip/Close capacitor voltage magnitude

[a] Per ISO 8601, years starting on a Thursday and leap years that start on a Wednesday have 53 weeks.

NOTE: Because ISO 8601 is used to determine the week of the year quantity, WEEK, certain corner cases can occur. For example, Sunday, January 1st, 2017, will be reported as occurring in WEEK 53, while the YEAR will report 2017. This is the result of ISO 8601 defining Sunday as the last day of the week.

SELOGIC Control Equation Operators

Use the analog comparators to create a Boolean result from an analog value, and Boolean operators to combine values with a resulting Boolean value. Edge-trigger operators provide a pulse output. Combine the operators and operands to form statements that evaluate complex logic. *Table 7.3* contains a summary of operators available in the SEL-651R-2.

Operator Precedence

When you combine several operators and operands within a single expression, the SEL-651R-2 evaluates the operators from left to right starting with the highest precedence operators working down to the lowest precedence. If you write an equation with three AND operators, for example SV01 AND SV02 AND SV03, each AND will be evaluated individually from left to right. If you substitute NOT SV04 for SV03 in the previous example, resulting in SV01 AND SV02 AND NOT SV04, the relay evaluates the NOT operation of SV04 first and uses the result in subsequent evaluation of the expression. Operator precedence is shown in *Table 7.3*.

Table 7.3   Operator Precedence (Sheet 1 of 2)

Operator	Description
( )	Parenthesis
NOT	Boolean Complement
R_TRIG	Rising Edge Trigger
F_TRIG	Falling Edge Trigger

7.4 | SELOGIC Control Equation Programming
SELOGIC Control Equation Operators

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Table 7.3   Operator Precedence (Sheet 2 of 2)

Operator	Description
<, >, <=, >=	Analog Comparison
=	Analog Equality Check
<>	Analog Inequality Check
AND	Boolean AND
OR	Boolean OR

Parentheses Operators

Use paired parentheses to control the execution order of operations in a SELOGIC control equation. Use as many as 14 nested sets of parentheses in each SELOGIC control equation. The relay calculates the result of the operation on the innermost pair of parentheses first and then uses this result with the remaining operations.

NOT Operator

Use the NOT operator to invert a Boolean value. Create a NOT function using the NOT operator. This function would be described mathematically by the equation $f(A) = NOT\ A$ and graphically by the following IEEE symbol:
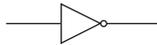
AND Operator

Use AND to combine two Boolean values according to the truth table shown in *Table 7.4*.

Table 7.4   AND Operator Truth Table

Value A	Value B	A AND B
0	0	0
0	1	0
1	0	0
1	1	1

Create an AND function using the AND operator. This function would be described mathematically by the equation $f(A,B) = A\ AND\ B$ and graphically by the following IEEE symbol:
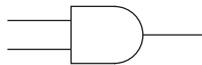
OR Operator

Use OR to combine two Boolean values according to the truth table shown in *Table 7.5*.

Table 7.5   OR Operator Truth Table

Value A	Value B	A OR B
0	0	0
0	1	1
1	0	1
1	1	1

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SELogic Control Equation Programming 7.5
SELogic Control Equation Operators

Create an OR function using the OR operator. This function would be described mathematically by the equation f(A,B) = A OR B and graphically by the following IEEE symbol:
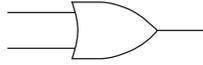
R_TRIG Operator

R_TRIG is a time-based function that creates a pulse when a rising edge is detected, as shown in *Figure 7.1*. Use R_TRIG to sense when a value changes from logical 0 to logical 1 and take action only after the value changes state.

R_TRIG applies to individual Relay Word bits only, not to groups of elements within parentheses. For example, the SELOGIC control equation event report generation setting uses several rising-edge operators:

ER := **R_TRIG 51P OR R_TRIG 51G1 OR R_TRIG OUT103**

When a logical 0 to logical 1 transition of ER is detected, the SEL-651R-2 generates an event report (if the relay is not already generating a report that encompasses the new transition). The rising-edge operators in the ER equation enable detection of each individual transition.

Suppose a ground fault occurs and a breaker failure condition finally results. *Figure 7.1* demonstrates the action of the rising-edge operator R_TRIG on the individual elements in setting ER.
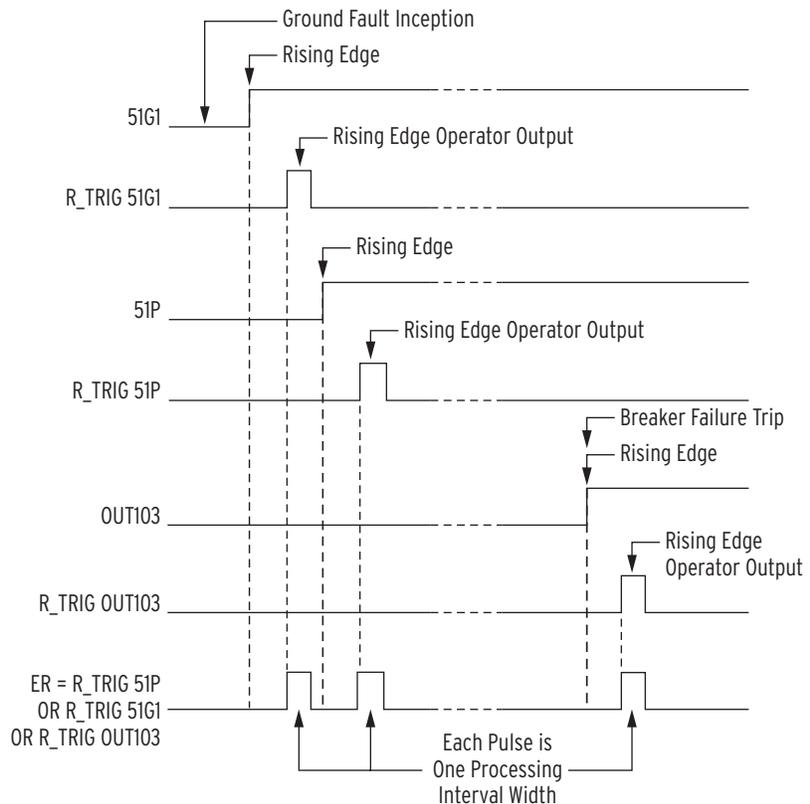
Figure 7.1   Rising Edge Operator Example

Note in *Figure 7.1* that setting ER detects three separate rising edges, because of the application of rising-edge operators R_TRIG. The rising edge operator R_TRIG in front of a Relay Word bit detects this logical 0 to logical 1 transition as a rising edge and as a result asserts to logical 1 for one processing interval. The assertions of 51G1 and 51P are close enough that they will be on

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the same event report (generated by 51G1 asserting first). The assertion of OUT103 for a breaker failure condition is some appreciable time later and will generate another event report, if the first event report capture has ended when OUT103 asserts.

If the rising-edge operators R_TRIG were not applied and setting ER was:

ER := **51P OR 51G1 OR OUT103**

the ER setting would not detect the assertion of OUT103, because 51G1 and 51P would continue to be asserted at logical 1.

F_TRIG Operator

F_TRIG is a time-based function that creates a pulse when a falling edge is detected, as shown in *Figure 7.2*. Use F_TRIG to sense when a value changes from logical 1 to logical 0 and take action only after the value changes state.

The argument of an F_TRIG statement must be a single Relay Word bit within the SEL-651R-2. An example of the relay detecting a falling edge of a calculated quantity is shown in *Figure 7.2*.

For example, suppose the SELOGIC control equation event report generation setting is set with the detection of the falling edge of an underfrequency element:

ER := **... OR F_TRIG 81D1T**

When frequency goes above the corresponding pickup level 81D1P, Relay Word bit 81D1T deasserts and an event report is generated (if the relay is not already generating a report that encompasses the new transition). This allows a recovery from an underfrequency condition to be observed. *Figure 7.2* demonstrates the action of the falling edge operator F_TRIG on the underfrequency element in setting ER.
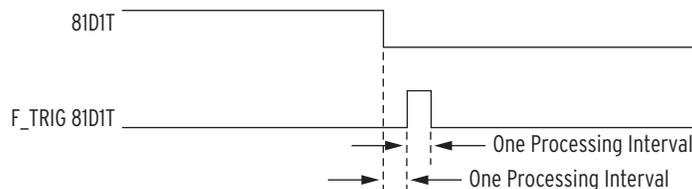
Figure 7.2   Falling Edge Operator Example

Analog Comparators and Checks

The <, >, <=, => comparator operators are generally used to determine states to drive a sequence of actions. Use the = check operator to check whether an integer value is equal to another integer value. Do not use the = check operator for noninteger values, because it is unlikely that they will ever be equal.

Math variables (MV01–MV64) provide storage locations for constants that may be used in analog comparisons. The values in these storage locations may be changed but the SEL-651R-2 does not support mathematical operands and functions on these or any other analog value. See *Figure 6.12* for an example of how a mathematical variable can be used.

Use the analog comparators to create your own schemes. For example, monitor the current (IA, IB, IC) harmonics on your system by creating a THD (total harmonic distortion) SCADA system alarm that you may use to initiate the retrieval of harmonic meter data. The following equation is an example of how to implement this alarm.

SV33 : = **(IAHT >= 5) OR (IBHT >= 5) OR (ICHT >= 5)**

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SELOGIC Control Equation Programming 7.7
SELOGIC Control Equation Functions

Comments

The pound symbol (#) is used as a comment operator. All characters entered after the # will be treated as text instead of logic.

SELOGIC control equation comments are very powerful tools for documenting and clarifying programming. Even programming that is well understood during installation and commissioning should have comments to help with any modifications needed later. These comments are stored in the SEL-651R-2.

SELOGIC Control Equation Functions

Variables/Timers

The SEL-651R-2 has sixty-four (64) SELOGIC control equation variables/timers. Each SELOGIC control equation variable/timer has a SELOGIC control equation setting input and variable/timer outputs as shown in *Figure 7.3*.

These timers have pickup and dropout time settings (SVnPU and SVnDO, n = 01 through 64).
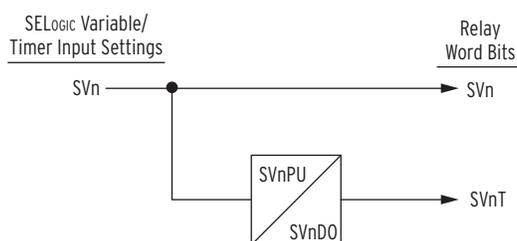
Figure 7.3   SELOGIC Control Equation Variables/Timers

If power to the SEL-651R-2 is lost, settings are changed for the active settings group, or the active settings group is changed, the SELOGIC control equation variables/timers are reset. Relay Word bits SVn and SVnT (n = 01–64) are reset to logical 0 and corresponding timer settings SVnPU and SVnDO are reloaded after power restoration, settings change, or active settings group switch.

Example 1

In the SELOGIC control equation settings, a SELOGIC control equation timer can be used for a simple breaker failure scheme:

SV02 := **TRIP3P**

The TRIP3P Relay Word bit is run through a timer for breaker failure timing. Timer pickup setting SV02PU is set to the breaker failure time (SV02PU := 12.00 cycles). Timer dropout setting SV02DO is set for a 2-cycle dropout (SV02DO := 2.00 cycles). The output of the timer (Relay Word bit SV02T) operates output contact OUT103.

OUT103 := **SV02T**

Example 2

Another application idea is dedicated breaker failure protection (see *Figure 7.4*):

SV06 := **IN101** # breaker failure initiate

SV07 := **(SV07 OR IN101) AND (50P1 OR 50G1)**

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OUT101 := **SV06T** # retrip

OUT102 := **SV07T** # breaker failure trip
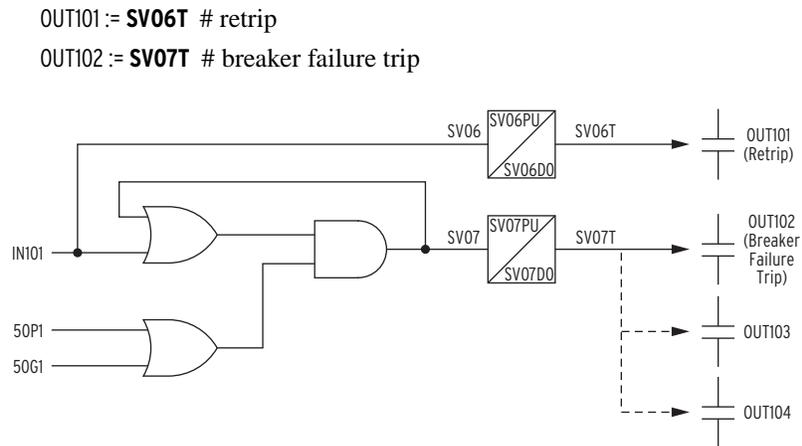
Figure 7.4   Dedicated Breaker Failure Scheme Created With SELOGIC Control Equation Variables/Timers

Note that the above SELOGIC control equation setting SV07 creates a seal-in logic circuit (as shown in *Figure 7.4*) by virtue of SELOGIC control equation setting SV07 being set equal to Relay Word bit SV07 (SELOGIC control equation variable SV07):

SV07 := **(SV07 OR IN101) AND (50P1 OR 50G1)**

Optoisolated input IN101 functions as a breaker failure initiate input. Phase instantaneous overcurrent element 50P1 and ground instantaneous overcurrent element 50G1 function as fault detectors.

Timer pickup setting SV06PU provides retrip delay, if desired, but can also be set to zero. Timer dropout setting SV06DO holds the retrip output (output contact OUT101) closed for extra time, if needed, after the breaker failure initiate signal (IN101) deasserts.

Timer pickup setting SV07PU provides breaker failure timing. Timer dropout setting SV07DO holds the breaker failure trip output (output contact OUT102) closed for extra time, if needed, after the breaker failure logic unlatches (fault detectors 50P1 and 50G1 dropout).

Note that *Figure 7.4* suggests the option of having output contacts OUT103 and OUT104 operate as additional breaker failure trip outputs. To do this make the following SELOGIC control equation settings:

OUT103 := **SV07T** # breaker failure trip

OUT104 := **SV07T** # breaker failure trip

Example 3

The seal-in logic circuit in the dedicated breaker failure scheme in *Figure 7.4* can be removed by changing the SELOGIC control equation setting SV07 to:

SV07 := **IN101 AND (50P1 OR 50G1)**

If the seal-in logic circuit is removed, optoisolated input IN101 (breaker failure initiate) has to be continually asserted for a breaker failure time-out.

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Timer Reset Conditions

The SELOGIC control equation variables/timers are reset to logical 0 if any of the following occur: power to the relay is lost, settings are changed for the active settings group, or the active settings group is changed. When Relay Word bits SVn and SVnT (n = 01–64) are reset to logical 0, corresponding timer settings SVnPU and SVnDO load up again.

Preceding *Figure 7.4* shows an effective seal-in logic circuit, created by use of Relay Word bit SV07 (SELOGIC control equation variable SV07) in SELOGIC control equation SV07:

SV07 := **(SV07 OR IN101) AND (50P1 OR 50G1)**

The seal-in logic circuit is broken by Relay Word bit SV07 being reset to logical 0 if any of the following occur: power to the relay is lost, settings are changed for the active settings group, or the active settings group is changed. Relay Word bit SV07T is also reset to logical 0 and timer settings SV07PU and SV07DO load up again. The inputs into this logic (IN101, 50P1, and 50G1) are then re-evaluated.

Latch Bits

Latch control switches (Latch Bits are the outputs of these switches) replace traditional latching relays. Traditional latching relays maintain their output contact state. The SEL-651R-2 latch control switches retain their state even when power to the relay is lost. If the latch control switch is set to a programmable output contact and power to the relay is lost, the state of the latch control switch is stored in nonvolatile memory, but the output contact will go to its de-energized state. When power to the relay is restored, the programmable output contact will go back to the state of the latch control switch after relay initialization.

Traditional latching relay output contact states are changed by pulsing the latching relay inputs (see *Figure 7.5*). Pulse the set input to close (set) the latching relay output contact. Pulse the reset input to open (reset) the latching relay output contact. Often the external contacts wired to the latching relay inputs are from remote control equipment (e.g., SCADA, RTU).
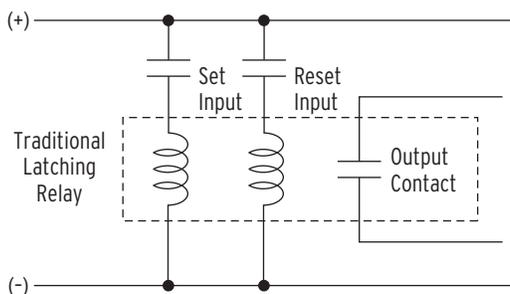
Figure 7.5   Traditional Latching Relay

Thirty-two latch control switches in the SEL-651R-2 provide latching relay functionality (see *Latch Bits Set/Reset SELOGIC Equations on page SET.38*).
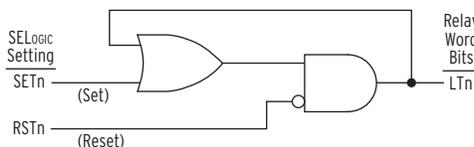
Figure 7.6   Latch Control Switches Drive Latch Bits LT01 Through LT032

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The output of the latch control switch in *Figure 7.6* is a Relay Word bit LT*n* (*n* = 01–32), called a latch bit. The latch control switch logic in *Figure 7.6* repeats for each latch bit LT01–LT32. Use these latch bits in SELᴏɢɪᴄ control equations.

These latch control switches each have the following SELᴏɢɪᴄ control equation settings:

SET*n* (set latch bit LT*n* to logical 1)

RST*n* (reset latch bit LT*n* to logical 0)

If setting SET*n* asserts to logical 1, latch bit LT*n* asserts to logical 1. If setting RST*n* asserts to logical 1, latch bit LT*n* deasserts to logical 0. If both settings SET*n* and RST*n* assert to logical 1, setting RST*n* has priority and latch bit LT*n* deasserts to logical 0.

Latch Bits: Application Ideas

Latch control switches can be used for such applications as:

➤ Reclosing relay enable/disable

➤ Ground relay enable/disable

➤ Sequence coordination enable/disable

Latch control switches can be applied to almost any control scheme. The following is an example of using a latch control switch to enable/disable the reclosing relay in the SEL-651R-2.

Example: Reclosing Relay Enable/Disable Setting

Use a latch control switch to enable/disable the reclosing relay in the SEL-651R-2. In this example, a SCADA contact is connected to optoisolated input IN104 as shown in *Figure 7.7*. Use a Remote Bit or Local Bit instead of an input if your application warrants it.

If the reclosing relay is enabled and the SCADA contact is pulsed, the reclosing relay is then disabled. If the SCADA contact is pulsed again, the reclosing relay is enabled again. Each pulse of the SCADA contact changes the state of the reclosing relay. The control operates in a cyclic manner. The SCADA contact is not maintained, just pulsed to enable/disable the reclosing relay.
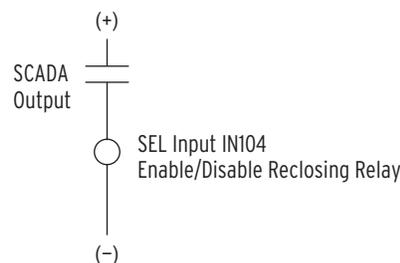
Figure 7.7 SCADA Contact Pulses Input IN104 to Enable/Disable Reclosing Relay

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This reclosing relay logic is implemented in the following SELOGIC control equation settings and is displayed in *Figure 7.8*. Note that the figure includes an extra timer that is not included in the settings. This timer will be used in the next example. *Figure 7.9* shows the timing for this example.

SET01 := **(R_TRIG IN104) AND (NOT LT01)**

RST01 := **(R_TRIG IN104) AND LT01**

79DTL3P := **NOT LT01**
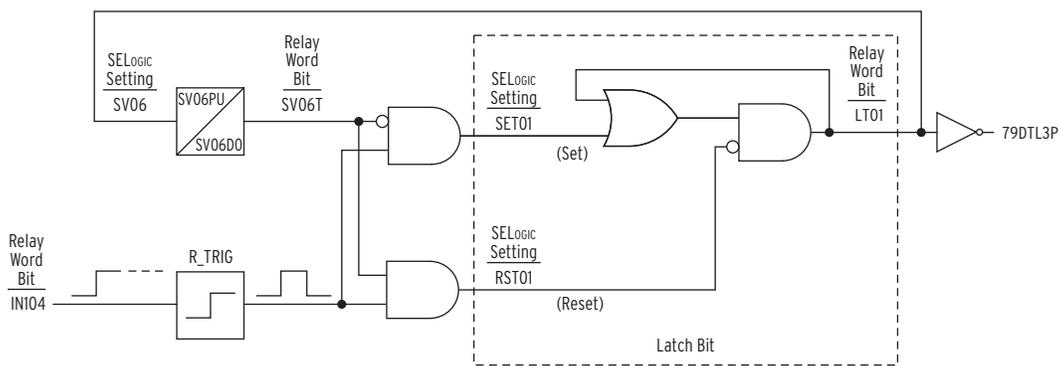
Figure 7.8   Single Input to Enable/Disable Reclosing
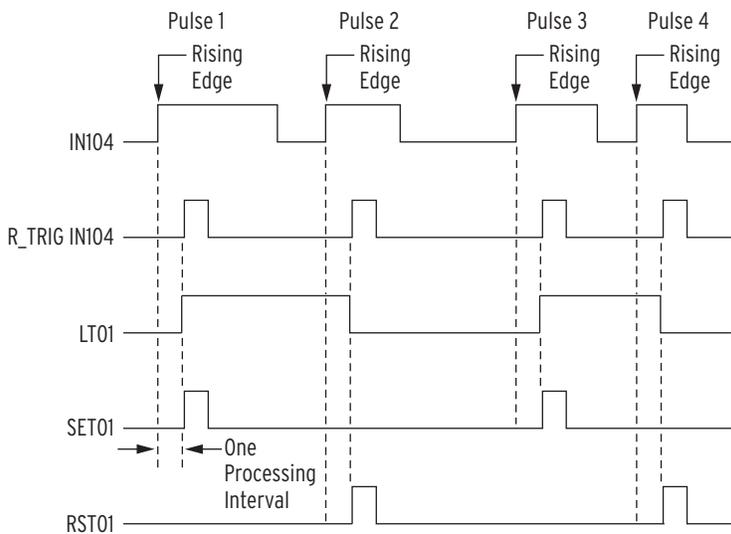
Figure 7.9   Latch Control Switch Operation Time Line

A variation of the previous example adds more security by adding a timer with equal pickup/dropout times as shown in *Figure 7.8*. Suppose that SV06PU and SV06DO are both set to 300 cycles. Then the SV06T timer keeps the state of latch bit LT01 from being able to be changed at a rate faster than once every 300 cycles (5 seconds). *Figure 7.10* shows the timing for this example.

SV06 := **LT01**

SET01 := **(R_TRIG IN104) AND (NOT SV06T)**

RST01 := **(R_TRIG IN104) AND SV06T**

79DTL3P := **NOT LT01**

Note that in *Figure 7.8* the latch control switch output (latch bit LT01) uses feedback for SELOGIC control equation settings SET01 and RST01. The feedback of latch bit LT01 determines whether input IN104 operates the

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SET01 or RST01 input. If latch bit LT01 = logical 0, input IN104 operates SET01 (set latch bit LT01). If latch bit LT0 = logical 1, input IN104 operates RST01 (reset latch bit LT01).
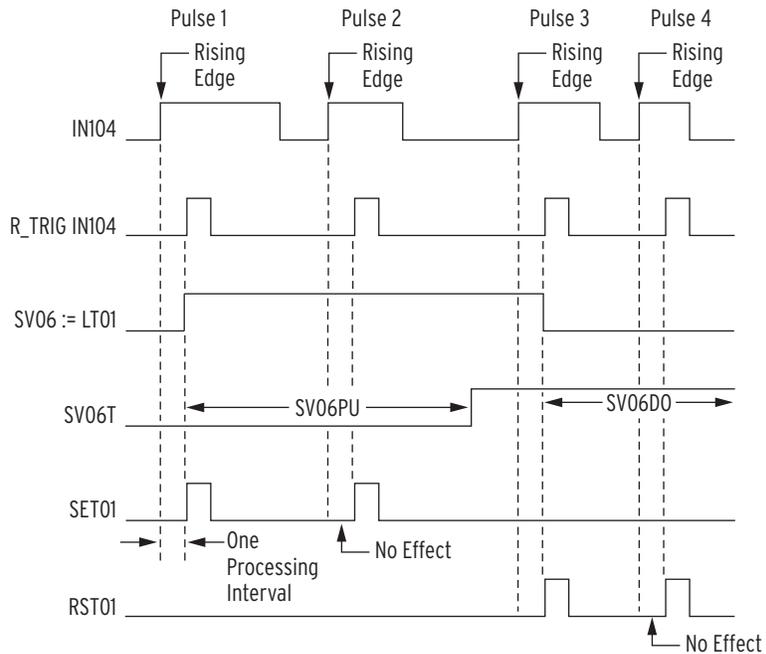
Figure 7.10   Latch Control Switch (With Time-Delay Feedback) Operation Time Line

Latch Bits: Nonvolatile State

Power Loss

The states of the latch bits (LT01–LT32) are retained if power to the relay is lost and then restored. If a latch bit is asserted (e.g., LT02 = logical 1) when power is lost, it is asserted (LT02 = logical 1) when power is restored. If a latch bit is deasserted (e.g., LT03 = logical 0) when power is lost, it is deasserted (LT03 = logical 0) when power is restored. This feature makes the latch bit feature behave the same as traditional latching relays. In a traditional installation, if power is lost to the panel, the latching relay output contact position remains unchanged.

Note: If a latch bit is set to a programmable output contact, such as OUT103 := LT02, and power to the relay is lost, the state of the latch bit is stored in nonvolatile memory but the output contact will go to its de-energized state. When power to the relay is restored, the programmable output contact will go back to the state of the latch bit after relay initialization.

Settings Change or Active Settings Group Change

If individual settings are changed (for the active settings group or one of the other settings groups) or the active settings group is changed, the states of the latch bits (Relay Word bits LT01–LT32) are retained, much like in the preceding *Power Loss* explanation.

If individual settings are changed for a settings group other than the active settings group, there is no interruption of the latch bits (the relay is not momentarily disabled).

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Enable Setting ELAT and Its Effect on Latch Bit Settings and Outputs

Presume ELAT := 2 and latch bit LT02 is asserted to logical 1 (because of the normal operation of corresponding settings SET02 and RST02). If ELAT is then changed to ELAT := 1, or N (settings SET02 and RST02 are no longer available for setting and are internally set: SET02 := NA, RST02 := NA), then latch bit LT02 retains the state it had before the settings change (LT02 remains asserted to logical 1). If ELAT is next changed back to ELAT := 2 (settings SET02 and RST02 are available again, but come forth set: SET02 := NA, RST02 := NA), then latch bit LT02 still retains the state it had before the settings change (LT02 remains asserted to logical 1). If settings SET02 and RST02 are then changed, latch bit LT02 can then change state, because of the normal operation of these corresponding settings.

Make Latch Control Switch Settings With Care

The latch bit states are stored in nonvolatile memory so they can be retained during power loss, settings change, or active settings group change. The nonvolatile memory is rated for a finite number of writes for all cumulative latch bit state changes. Exceeding the limit can result in a FLASH self-test failure. **An average of 70 cumulative latch bit state changes per day can be made for a 25-year relay service life**.

This requires that SELOGIC control equation settings SETn and RSTn for any given latch bit LTn (n = 01–32) be set with care. Settings SETn and RSTn must not result in continuous cyclical operation of latch bit LTn. Use timers to qualify conditions set in settings SETn and RSTn. If any optoisolated inputs IN101–IN107 are used in settings SETn and RSTn, the inputs have their own debounce timer that can help in providing the necessary time qualification.

In the preceding reclosing relay enable/disable example application (see *Figure 7.7*), the SCADA contact cannot be asserted/deasserted continuously, which would cause latch bit LT01 to change state continuously. Note that the rising-edge operators in the SET01 and RST01 settings keep latch bit LT01 from cyclically operating for any single assertion of the SCADA contact.

Counters

SELOGIC control equation counters are up- or down-counting elements. These counters conform to the standard counter function block in IEC 1131-3 First Edition 1993-03 International Standard for Programmable Controllers—Part 3: Programming Languages, as shown by the symbol in *Figure 7.11*.

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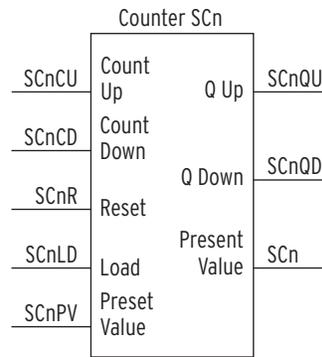
Figure 7.11   Up/Down Counters

Table 7.6 describes the Boolean input settings, counter value setting, and Boolean outputs of the counters. Sixteen counters are available, $n = 01$–16. See *SEL<small>OGIC</small> Counter Settings on page SET.47*.

Table 7.6   Counter Inputs and Outputs

Name	Type	Description
SCnLD	Active High Input	Load counter with the preset value (follows SELOGIC setting)
SCnPV	Input Value	This Preset Value is loaded when SCnLD pulsed. This Preset Value is used as a maximum count in the SCnQU comparison (follows SELOGIC setting)
SCnCU	Rising-Edge Input	Count Up increments the counter (follows SELOGIC setting)
SCnCD	Rising-Edge Input	Count Down decrements the counter (follows SELOGIC setting). The counter freezes if set to NA. See **NOTE** under *SELOGIC Counter Settings on page SET.47*.
SCnR	Active High Input	Reset counter to zero (follows SELOGIC setting).
SCnQU	Active High Output	This Q Up output asserts when the Preset Value (maximum count) is reached (SCn = SCnPV, $n = 01$ to 16).
SCnQD	Active High Output	This Q Down output asserts when the counter is equal to zero (SC$n = 0$, $n = 01$ to 16).
SCn	Output Value	This counter output is an analog value that may be used with analog comparison operators in a SELOGIC control equation, or viewed with the **COUNTER** command.

Viewing Counters

The serial port command **COUNTER** displays the present value of SC01–SC16 (see *COUNTER Command (View SEL<small>OGIC</small> Counters) on page 10.46*).

Counters: Application Ideas

Counters can be used for such applications as:

➤ Keeping track of a tap-changer position

➤ Switching and cycling of a capacitor bank

➤ Peak shaving with control of on-site generation

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Examples

Example 7.1 illustrates how to use the SELOGIC control equation counters to limit the demand by starting an on-site 60 Hz diesel generator.

EXAMPLE 7.1

When the three-phase demand is greater than 100 kW for greater than 10 minutes, the diesel generator should start to pick up load. The generator should be started in 5 minutes when demand is greater than 125 kW. Also, if the demand is greater than 150 kW, the diesel generator should start immediately.

Figure 7.12 shows the logic required to create the 10-second periodic waveforms R_TRIG SV10 and F_TRIG SV10 shown in Figure 7.13. One periodic waveform is used to increment a counter when the three-phase power is above the 3PWR1 power element pickup (3PWR1P set equivalent to 100 kW primary) and both periodic waveforms are used when the three-phase power is above the 3PWR2 power element pickup (3PWR2P set equivalent to 125 kW primary). The R_TRIG SV10 waveform is used to decrement the counter when the three-phase power is below both thresholds.
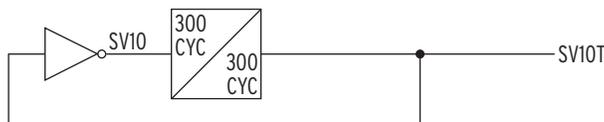
Figure 7.12   SELOGIC Variable SV10 Timing Logic Used in Example 7.1
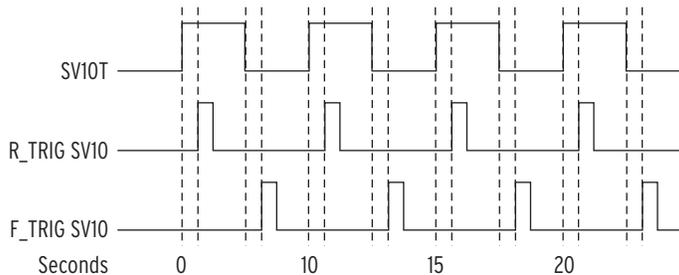
Figure 7.13   SELOGIC Variable SV10 Timer Output

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Make the following settings to implement this function:

SV10PU := **300.00**

SV10DO := **300.00**

SV10 := **NOT SV10T** 10 second period

ESC := **1** enable one counter

ESV := **10** enable ten (or more) timers

SC01PV := **60** maximum counter value

SC01R := **IN101** disable the starting of the generator if desired (reset counter to zero)

SC01LD := **IN102 OR 3PWR3** start the generator immediately (set counter to maximum value; 3PWR3 asserts at the equivalent of 150 kW primary)

SC01CU := **R_TRIG SV01 AND 3PWR1 OR F_TRIG SV01 AND 3PWR2** increment counter SC01, faster when the demand is higher than 125 kW (3PWR1 asserts at the equivalent of 100 kW primary; 3PWR2 asserts at the equivalent of 125 kW primary)

SC01CD := **R_TRIG SV01 AND NOT 3PWR1** decrement counter SC01 when the demand is below 100 kW

OUT102 := **(SC01 > 48)** warning that diesel generator is about to start

OUT101 := **SC01QU** start generator signal

Settings for three-phase power elements 3PWR1, 3PWR2, and 3PWR3 are found in Table 4.21.

Because demands are slow-changing values, it does not make sense to check them continuously. The ten-second period makes the SV10T preset value setting easier to determine.

$$\text{Preset Value} = \frac{10 \text{ minutes} \cdot 60 \text{ s/minute}}{10 \text{ s/count}} = 60 \text{ counts}$$

Figure 7.14 is provided as a reference to this example.

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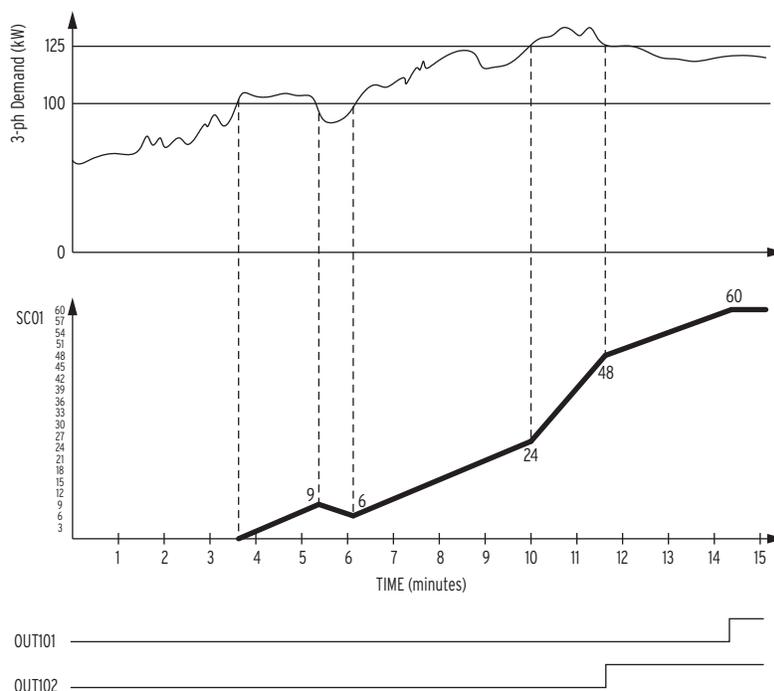
Figure 7.14   SELogic Control Equation Counter Example

Example 7.2 illustrates how to use SELOGIC timers and counters to pulse LEDs and lock pushbuttons.

EXAMPLE 7.2

Figure 7.15 shows the logic required to pulse the LED and lock the pushbuttons. Timing is shown in Figure 7.16. Pushbutton 6, labeled **PUSHBUTTONS LOCKED**, is used to lock the enable/disable selection state of pushbuttons 1, 2, 3, 5, 7, 8, 9, and 10. If pushbutton 6 is pressed and held, pushbutton 6 LED will flash two (2) times and remain illuminated on the third flash. The designated pushbuttons are now locked in the last state selected. If pushbutton 6 is pressed and held a second time, the pushbutton LED will flash on two (2) times, then remain off. The designated pushbuttons are now unlocked and each can be toggled between enable/disable.

Timer SV01 is used to generate an output pulse of 30 cycles on and 30 cycles off. The on-pulse illuminates the pushbutton 6 LED and increments the counter by one. The counter has a maximum range of three. The counter limits LED illumination to two flashes and a third illumination remaining on for lock conditions and two flashes, then remaining off for unlock conditions.

See partial logic and settings from relay default settings to clarify the example.

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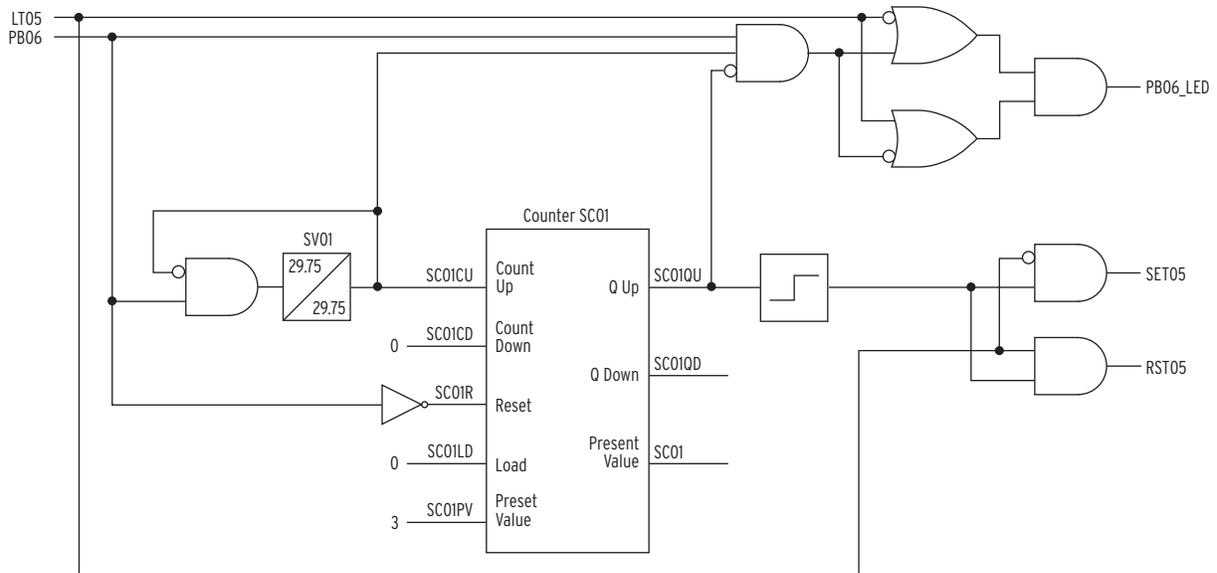
Figure 7.15   Pulse LED and Lock Pushbuttons Example

Make the following settings to implement these functions:

SET05 := **R_TRIG SC01QU AND NOT (LT05)** lock pushbuttons, must press for three seconds (locked when LT05 deasserted)

RST05 := **R_TRIG SC01QU AND LT05**

SV01PU := **29.75** with processing time ≈ 30 cycles

SV01DU := **29.75** with processing time ≈ 30 cycles

SV01 := **NOT SV01T AND PB06** 1 Hz blink generator for lock pushbutton

SC01PV := **3** maximum count

SC01R := **NOT PB06** reset counter

SC01LD := **0** set to 1 to defeat blink delay

SC01CU := **SV01T** count the blinks for lock pushbuttons control

SC01CD := **0** count down, not used

PB06_LED := **NOT (LT05 AND NOT (SV01T AND PB06 AND NOT (SC01QU)) OR NOT (LT05) AND SV01T AND PB06 AND NOT (SC01QU))** pushbuttons locked

[= NOT LT05 OR (PB06 AND SV01T AND NOT SC01QU)
  AND
  LT05 OR NOT(PB06 AND SV01T AND NOT SC01QU), as shown in
  Figure 7.15]

See latch bit equations for pushbutton use of LTO5.
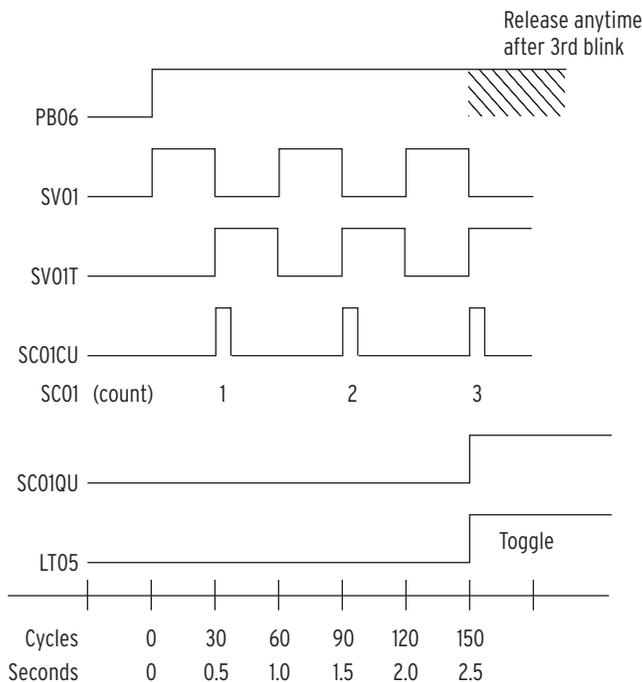
Figure 7.16 SELOGIC Control Equation Time and Counter

Counters: Volatile State and Disabled Behavior

Power Loss

SELOGIC counters SC01–SC16 are reset to a count value of zero after power
to the SEL-651R-2 control module is lost and then restored. The counter
output Relay Word bits behave as explained below for enabled and disabled
counters.

Settings Change or Active Group Change

SELOGIC counters SC01–SC16 are retained through settings changes and
active group changes.

Enabled and Disabled Counters

If a settings change or group change results in a different number of enabled
counters (logic enable setting ESC changes), the counters behave as follows:

➤ newly enabled counters (or enabled counters after power is
   restored) start at a count value of zero, with output
   SCnnQD = logical 1 and SCnnQU = logical 0

➤ disabled counters are set to zero, with both outputs SCmmQD
   and SCmmQU forced to logical 0

Recloser Status Inputs

Six recloser status inputs are provided for recloser control operations (see
Recloser Interface Connection Details (Control Cable Interface) on page 2.59
for the various configurations). These status inputs are rated for nominal

12 Vdc and are not optically isolated. Make use of these inputs by using their Relay Word bits IN201–IN206 in SELOGIC control equations (see ratings in *Specifications on page 1.9*).

Figure 7.17 is used for the following discussion/examples and shows the resultant Relay Word bits (Relay Word bits IN201–IN206) that follow corresponding timers. The figure shows examples of energized and de-energized inputs and corresponding Relay Word bit states. Assert an input by applying rated control voltage to the appropriate connector pin.
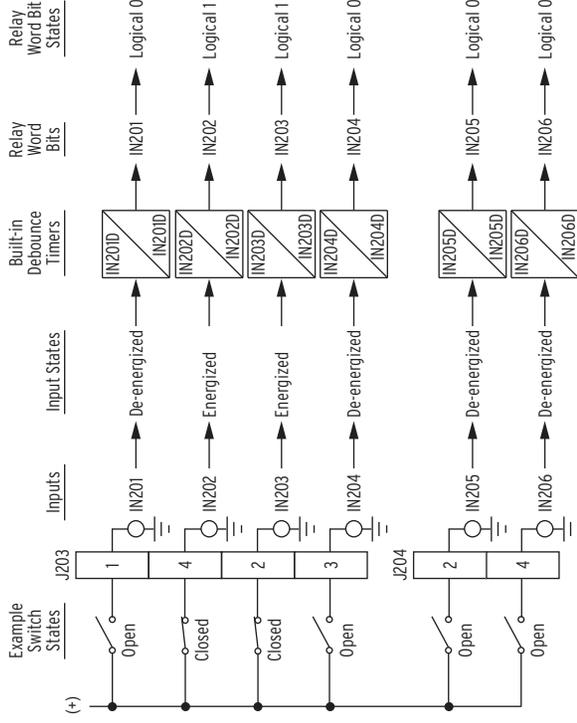
Figure 7.17   Example Operation of Recloser Status Inputs

Each input has a dedicated pickup/dropout timer (IN201D–IN206D) that is used to help eliminate unnecessary transitions caused by bouncing contacts. In Global settings, set EICIS := Y to enable modification of these settings. Default time is 0.75 cycles, except for G&W Viper-ST, Tavrida OSM A1_2, Multi-Recloser Interface, and Siemens SDR (1.5 cycles). The pickup/dropout timers IN201D–IN206D have a setting range of 0.00–2.00 cycles.

The relay takes the entered timer setting and internally runs the timer at the nearest 1/16-cycle. For example, if setting IN205D = 0.80, internally the timer runs at the nearest 1/16-cycle: 13/16-cycles (13/16 = 0.8125). The relay processing interval is 1/4-cycle, so Relay Word bits IN201–IN206 are updated every 1/4-cycle.

For most applications, the input pickup/dropout debounce timers should be set in 1/4-cycle increments. For example, in the factory-default settings, all the input pickup/dropout debounce timers are set at 0.75-cycle, such as IN204D := 0.75.

If more than 2 cycles of debounce are needed, run Relay Word bit IN20*n* (*n* = 1–6) through a SELOGIC variable timer (see *Figure 7.3*) and use the output of the timer for input functions.

Input
Debounce Timers

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Optoisolated Inputs

You can order optoisolated inputs IN101–IN107 as an option. These inputs are located on the main board of the SEL-651R-2 (see *Figure 2.5* and *Figure 2.9*). These inputs have debounce timers similar to those described in Recloser Status Inputs; the default time is 0.5 cycles, except for IN105–IN107 on the Multi-Recloser Interface (1.5 cycles).

You can order the optoisolated inputs with IN101 and IN102 pickups of 125 Vdc as an option. The 125 Vdc option includes debounce settings range value AC. The AC setting allows the input to sense ac control signals. When you use the AC setting, the input has a maximum pickup time of 0.75 cycles and a maximum dropout time of 1.25 cycles. The AC setting qualifies the input by not asserting until 2 successive 1/16-cycle samples are higher than the optoisolated input voltage threshold and not deasserting until 16 successive 1/16-cycle samples are lower than the optoisolated input voltage threshold.

Figure 7.18 shows the resultant Relay Word bits (Relay Word bits IN101–IN107) that follow corresponding timers.

NOTE: Optoisolated inputs are level-sensitive, meaning that they require more than one half of rated voltage to assert. Refer to Specifications on page 1.9 for proper ac and dc voltages required for secure and dependable input operation.

NOTE: Optoisolated inputs are not polarity-sensitive.
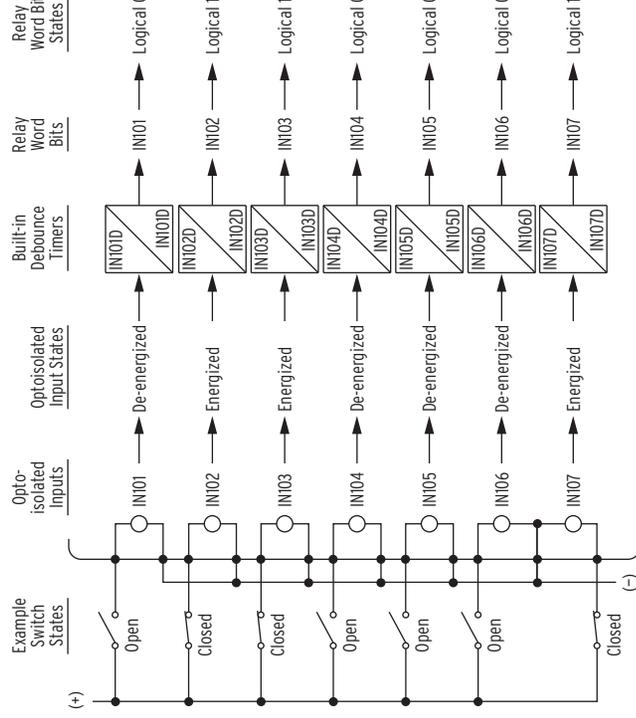
Figure 7.18   Example Operation of Optoisolated Inputs

Screw and torque information for optoisolated inputs IN101–IN107 is found in *Additional Relay Connections on page 2.50*.

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Remote Bits

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Remote Bits

As many as 32 remote control switches are operated via the serial communications port only. They may be operated through use of any of the following:

➤ SEL ASCII command CONTROL as described in *Section 10: Communications*.

➤ Fast Operate commands as described in *Appendix C: Compressed ASCII Commands*.

➤ DNP3 Objects 10 and 12 as described in *Appendix E: DNP3 Communications*.
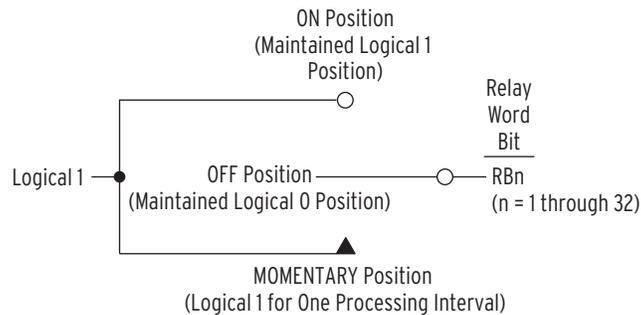
Figure 7.19   ON/OFF/MOMENTARY Remote Control Switch

The output of the switch in *Figure 7.19* is a Relay Word bit (RB01–RB32) called a Remote Bit and repeats for each Remote Bit. Use these Remote Bits in SEL_{OGIC} control equations.

Remote Bit RBn may be in the ON (RBn = logical 1) position, in the OFF (RBn = logical 0) position, or maintained in the OFF (RBn = logical 0) position and pulsed to the MOMENTARY (RBn = logical 1) position for one processing interval (1/4 cycle).

The state of each remote bit (Relay Word bits RB01–RB32) is retained if relay settings are changed (for the active settings group or one of the other settings groups) or the active settings group is changed.

Remote Bits: Application Ideas

With SEL_{OGIC} control equations, the remote bits can be used in applications similar to those that use local bits.

Also, remote bits can be used much as optoisolated inputs are used in operating latch control switches. Pulse (momentarily operate) the remote bits for this application.

Remote Bits: Momentary Position

This subsection describes how the momentary position of the remote control switch operates via the SEL ASCII command **CONTROL**. It operates in the same manner when used with a Fast Operate or DNP3 pulse command.

Use the **CON n** command and **PRB n** subcommand to put the remote control switch in the momentary ON position for one processing interval, regardless of its initial state. The remote control switch is then placed in the OFF position.

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If RB*n* is initially at logical 0, pulsing it with the **CON *n*** command and **PRB *n*** subcommand will change RB*n* to a logical 1 for one processing interval, and then return it to a logical 0. If RB*n* is initially at logical 1 instead, pulsing it with the **CON *x*** command and **PRB *x*** subcommand will change RB*n* to a logical 0.

Remote Bit: Volatile State

The states of the remote bits (Relay Word bits RB01–RB32) are not retained if power to the relay is lost and then restored. The remote control switches always come back in the OFF position (corresponding remote bit is deasserted to logical 0) when power is restored to the relay.

Multiple Settings Groups

The SEL-651R-2 has eight independent settings groups. Each settings group has complete relay (overcurrent, reclosing, frequency, etc.) and SELOGIC control equation settings. The active settings group can be:

➤ Shown or selected with the SEL ASCII serial port **GROUP** command as described in *Section 10: Communications*.

➤ Shown or selected with the MAIN menu Set/Show menu item and the Active Group submenu item as described in *Section 11: Front-Panel Operations*.

➤ Selected with SELOGIC control equation settings SS1–SS8. Settings SS1–SS8 have priority over the serial port **GROUP** command, the front-panel **ALT SETTINGS** pushbutton, and the DNP3 and Modbus controls in selecting the active settings group. Use remote bits in these equations to select settings groups with Fast Operate commands as described in *Appendix C: Compressed ASCII Commands*.

➤ Shown with DNP3 Objects 20 and 22 as described in *Appendix E: DNP3 Communications* and selected with Objects 40 and 41.

➤ Shown with Modbus function code 03h or 04h and selected with function code 06h or 10h as described in *Appendix K: Modbus RTU and TCP Communications*.

Settings Groups: Application Ideas

Settings groups can be used for such applications as:

➤ Sectionalizing, midpoint, and tie reclosers in energized and de-energized states

➤ Environmental conditions such as winter storms, periods of high summer heat, etc.

➤ Hot-line tag that disables closing and sensitizes protection

➤ Commissioning and operation

Active Settings Group Indication

Only one settings group can be active at a time. Relay Word bits SG1–SG8 indicate the active settings group, as shown in *Table 7.7*.

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Multiple Settings Groups

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Table 7.7   Definitions for Active Settings Group Indication Relay Word Bits SG1 Through SG8

Relay Word Bit	Definition
SG1	Indication that Settings Group 1 is the active settings group
SG2	Indication that Settings Group 2 is the active settings group
SG3	Indication that Settings Group 3 is the active settings group
SG4	Indication that Settings Group 4 is the active settings group
SG5	Indication that Settings Group 5 is the active settings group
SG6	Indication that Settings Group 6 is the active settings group
SG7	Indication that Settings Group 7 is the active settings group
SG8	Indication that Settings Group 8 is the active settings group

For example, if Settings Group 4 is the active settings group, Relay Word bit SG4 asserts to logical 1 and the other associated Relay Word bits (SG1, SG2, SG3, SG5, SG6, SG7, and SG8) deassert to logical 0.

Active Settings Group Selection

The Global settings class contains the SELᴏɢɪᴄ control equation settings SS1–SS8, as shown in *Table 7.8*.

Table 7.8   Definitions for Active Settings Group Switching SELᴏɢɪᴄ Control Equation Settings SS1 Through SS8

Setting	Definition
SS1	go to (or remain in) Settings Group 1
SS2	go to (or remain in) Settings Group 2
SS3	go to (or remain in) Settings Group 3
SS4	go to (or remain in) Settings Group 4
SS5	go to (or remain in) Settings Group 5
SS6	go to (or remain in) Settings Group 6
SS7	go to (or remain in) Settings Group 7
SS8	go to (or remain in) Settings Group 8

The operation of these settings is explained with the following example:

Assume the active settings group starts out as Settings Group 3. Corresponding Relay Word bit SG3 is asserted to logical 1 as an indication that Settings Group 3 is the active settings group.

With Settings Group 3 as the active settings group, setting SS3 has priority. If setting SS3 is asserted to logical 1, Settings Group 3 remains the active settings group, regardless of the activity of settings SS1, SS2, SS4, SS5, SS6, SS7, and SS8. With settings SS1–SS8 all deasserted to logical 0, Settings Group 3 still remains the active settings group.

With Settings Group 3 as the active settings group, if setting SS3 is deasserted to logical 0 and one of the other settings (e.g., setting SS5) asserts to logical 1, the relay switches from Settings Group 3 as the active settings group to another settings group (e.g., Settings Group 5) as the active settings group, after qualifying time setting TGR:

TGR   Group Change   (settable from 0.00 to 16000.00 cycles)
            Delay Setting

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In this example, TGR qualifies the assertion of setting SS5 before it can change the active settings group.

Active Settings Group Changes

The recloser control is disabled for less than 1 second while in the process of changing active settings groups. Relay elements, timers, and logic are reset, unless indicated otherwise in the specific logic description. For example, local bit (LB01–LB16), remote bit (RB01–RB32), and latch bit (LT01–LT32) states are retained during an active settings group change. The output contacts do not change state until the relay enables in the new settings group and the SELogic control equations are processed to determine the output contact status for the new group. For instance, if setting OUT105 := 1 (logical 1) in Group 2 and setting OUT105 := 1 (logical 1) in Group 3, and the relay is switched from Group 2 to Group 3, OUT105 stays energized before, during, and after the group change. However, if the Group 3 setting was OUT105 := 0 (logical 0) instead, then OUT105 remains energized until the relay enables in Group 3, solves the SELogic control equations, and causes OUT105 to de-energize. See *Figure 7.28* for examples of output contacts in the de-energized state (i.e., corresponding output contact coils de-energized).

Relay Word bit GRPSW will pulse for approximately 1 second when the active settings group is changed. Relay Word bit GRPSW is part of the default SALARM SELogic control equation setting (see *Global Settings on page SET.1*).

Example 1: Active Settings Group Switching

Use a single optoisolated input to switch between two settings groups in the SEL-651R-2. In this example, optoisolated input IN105 on the relay is connected to a SCADA contact in *Figure 7.20*. Each pulse of the SCADA contact changes the active settings group from one settings group, such as Settings Group 1, to another, such as Settings Group 4. The SCADA contact is not maintained, just pulsed to switch from one active settings group to another.
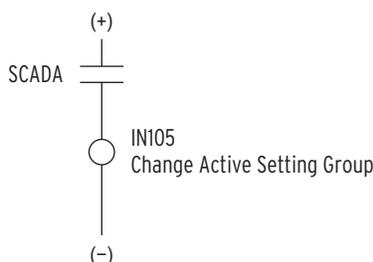
Figure 7.20   SCADA Contact Pulses Input IN105 to Switch Active Settings Group Between Settings Groups 1 and 4

If Settings Group 1 is the active Settings group and the SCADA contact is pulsed, Settings Group 4 becomes the active settings group. If the SCADA contact is pulsed again, Settings Group 1 becomes the active settings group again. The settings group control operates in a cyclical manner.

This logic is implemented in the SELogic control equation settings in *Table 7.9*.

Table 7.9   SELogic Control Equation Settings for Switching Active Settings Group Between Setting Groups 1 and 4 (Sheet 1 of 2)

Settings Group 1	Settings Group 4
SV08PU := 60.00	SV08PU := 60.00
SV08DO := 0.00	SV08DO := 0.00
SV08 := SG1	SV08 := SG4

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Multiple Settings Groups

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Table 7.9   SELᴏɢɪᴄ Control Equation Settings for Switching Active Settings Group Between Setting Groups 1 and 4 (Sheet 2 of 2)

Settings Group 1	Settings Group 4
Global Settings	
SS1 := IN105 AND SV08T AND NOT SG1	
SS2 := 0	
SS3 := 0	
SS4 := IN105 AND SV08T AND NOT SG4	
SS5 := 0	
SS6 := 0	
SS7 := 0	
SS8 := 0	

SELᴏɢɪᴄ control equation timer input setting SV08 in *Table 7.9* has logic output SV08T, shown in operation in *Figure 7.21* for both Settings Groups 1 and 4. The settings for SS1 and SS4 include expressions that steer the IN105 assertion to the appropriate setting. SS1 is only allowed to operate when the recloser control is not in Group 1, and SS4 is only allowed to operate when the recloser control is not in Group 4. These details are explained below *Figure 7.21*.
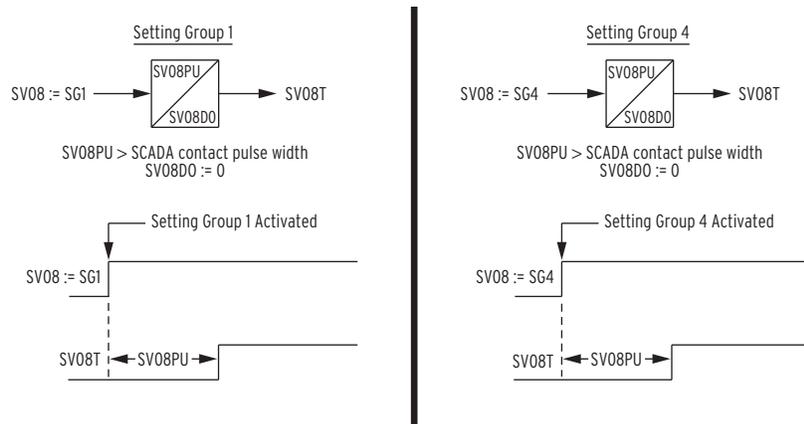
Figure 7.21   SELᴏɢɪᴄ Control Equation Variable Timer SV08T Used in Settings Group Switching

In this example, timer SV08T is used in both settings groups: different timers could have been used with the same operational result. The timers reset during the settings group change, allowing the same timer to be used in both settings groups.

Timer pickup setting SV08PU is set greater than the pulse width of the SCADA contact (see *Figure 7.20*). This allows only one active settings group change, such as from Settings Group 1 to 4, for each pulse of the SCADA contact and subsequent assertion of input IN105. The function of the SELᴏɢɪᴄ control equations in *Table 7.9* becomes more apparent in the following example scenario.

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Start Out in Settings Group 1

The recloser control has been in Settings Group 1 for some time, with timer logic output SV08T asserted to logical 1, thus enabling SELOGIC control equation setting SS4 for the assertion of input IN105. The inclusion of AND NOT SG1 in the setting for SS1 prevents SS1 from detecting the next IN105 assertion (see *Figure 7.22*).

Switch to Settings Group 4

The SCADA contact pulses input IN105, and the active settings group changes to Settings Group 4 after qualifying time setting TGR (perhaps set at a cycle or so to qualify the assertion of setting SS4). Optoisolated input IN105 also has its own built-in debounce timer (IN105D) available.

Note that *Figure 7.22* shows both Settings Group 1 and Settings Group 4 settings. The Settings Group 1 settings (near the top of *Figure 7.22*) are enabled only when Settings Group 1 is the active settings group and likewise for the Settings Group 4 settings near the bottom of the figure. The group selection settings, SS1 and SS4, are Global settings and are enabled in every settings group.

Settings Group 4 is now the active settings group, and Relay Word bit SG4 asserts to logical 1. After the relay has been in Settings Group 4 for a time period equal to SV08PU, the timer logic output SV08T asserts to logical 1, thus enabling SELOGIC control equation setting SS1 for a new assertion of input IN105. The inclusion of AND NOT SG4 in the setting for SS4 prevents SS4 from detecting the next IN105 assertion.

Note that input IN105 is still asserted because Settings Group 4 is activated. Pickup time SV08PU keeps the continued assertion of input IN105 from causing the active settings group to revert back again to Settings Group 1 for a single assertion of input IN105. This keeps the active settings group from being changed at a time interval less than time SV08PU.

Switch Back to Settings Group 1

The SCADA contact pulses input IN105 a second time, and the active settings group changes back to Settings Group 1 after qualifying time setting TGR, perhaps set at a cycle or so to qualify the assertion of setting SS1. Optoisolated input IN105 also has its own built-in debounce timer IN105D available. The timing is shown in *Figure 7.22*.

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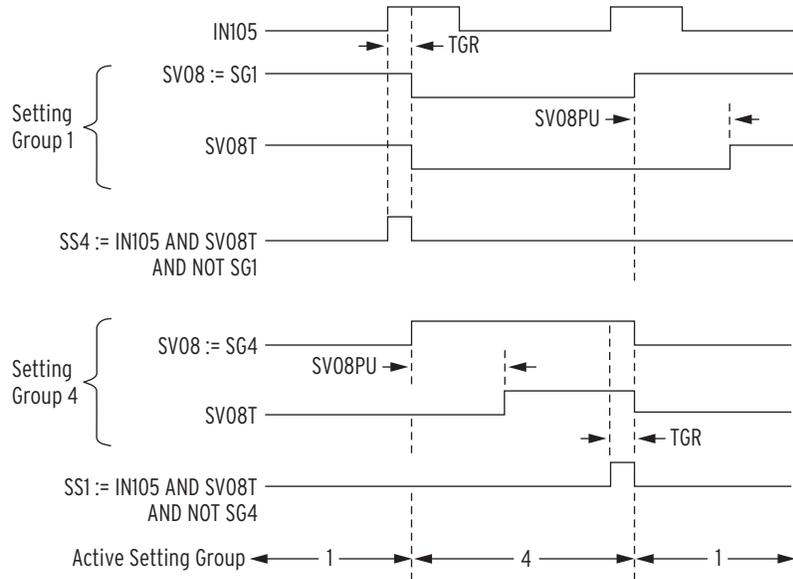
Figure 7.22 Active Settings Group Switching (With Single Input) Timing

Example 2: Active Settings Group Switching

Use three optoisolated inputs to switch between the eight settings groups in the SEL-651R-2. In this example, optoisolated inputs IN101, IN102, IN103, and IN104 on the recloser control are connected to a rotating selector switch as shown in *Figure 7.23*.
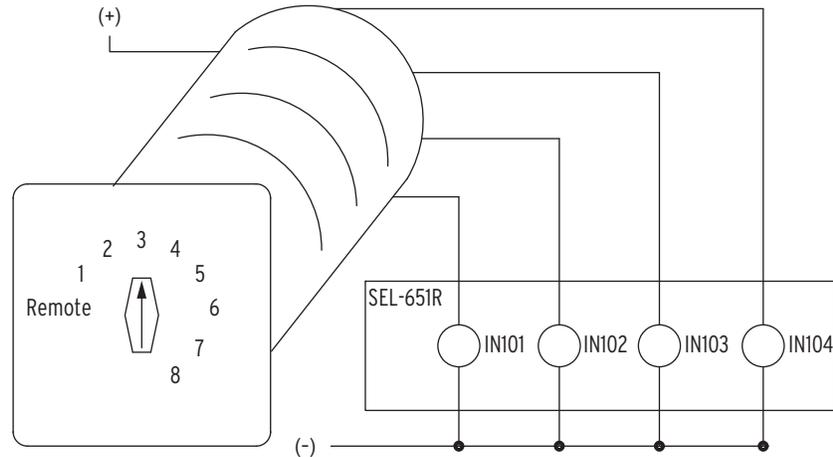
Figure 7.23 Rotating Selector Switch Connected to Inputs IN1O1, IN1O2, IN1O3, and IN1O4 for Active Settings Group Switching

The selector switch has multiple internal contacts arranged to assert inputs IN101, IN102, IN103, and IN104, dependent on the switch position. As shown in *Table 7.10*, when the selector switch is moved from one position to another, a different settings group is activated. The logic is implemented in the SELogic control equation settings in *Table 7.10*.

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Table 7.10 Active Settings Group Switching Input Logic

Input States				Active Settings Group	SELogic Settings
IN104	IN103	IN102	IN101		
0	0	0	0	Remote	
0	0	0	1	Group 1	SS1 := NOT IN104 AND NOT IN103 AND NOT IN102 AND IN101
0	0	1	0	Group 2	SS2 := NOT IN104 AND NOT IN103 AND IN102 AND NOT IN101
0	0	1	1	Group 3	SS3 := NOT IN104 AND NOT IN103 AND IN102 AND IN101
0	1	0	0	Group 4	SS4 := NOT IN104 AND IN103 AND NOT IN102 AND NOT IN101
0	1	0	1	Group 5	SS5 := NOT IN104 AND IN103 AND NOT IN102 AND IN101
0	1	1	0	Group 6	SS6 := NOT IN104 AND IN103 AND IN102 AND NOT IN101
0	1	1	1	Group 7	SS7 := NOT IN104 AND IN103 AND IN102 AND IN101
1	0	0	0	Group 8	SS8 := IN104 AND NOT IN103 AND NOT IN102 AND NOT IN101

The settings in *Table 7.10* are made in Global settings.

Selector Switch Starts Out in Position 3

If the selector switch is in position 3 in *Figure 7.23*, Settings Group 3 is the active settings group (Relay Word bit SG3 = logical 1). Inputs IN101 and IN102 are energized and inputs IN103 and IN104 are de-energized:

SS3 := **NOT IN104 AND NOT IN103 AND IN102 AND IN101**
  := **NOT (logical 0) AND NOT (logical 0) AND (logical 1) AND**
  (logical 1) = logical 1

To get from the position 3 to position 5 on the selector switch, the switch passes through the position 4. The switch is only briefly in position 4:

SS4 := **NOT IN104 AND IN103 AND NOT IN102 AND NOT IN101**
  := **NOT (logical 0) AND (logical 1) AND NOT (logical 0) AND NOT**
  (logical 0) = logical 1

but not long enough to be qualified by time setting TGR to change the active settings group to Settings Group 4 (see *Figure 7.24*). For such a rotating selector switch application, qualifying time setting TGR is typically set at 180 to 300 cycles. Set TGR long enough to allow the selector switch to pass through intermediate positions, without changing the active settings group, until the switch rests on the desired settings group position.

Selector Switch Switched to Position 5

If the selector switch rests on position 5 in *Figure 7.23*, Settings Group 5 becomes the active settings group (after qualifying time setting TGR; Relay Word bit SG5 = logical 1). Inputs IN101 and IN103 are energized and IN102 and IN104 are de-energized:

SS5 := **NOT IN104 AND IN103 AND NOT IN102 AND IN101**
  := **NOT (logical 0) AND NOT (logical 1) AND NOT (logical 0) AND**
  (logical 1) = logical 1

To get from position 5 to position REMOTE on the selector switch, the switch passes through the positions 4, 3, 2, and 1. The switch is only briefly in these positions, but not long enough to be qualified by time setting TGR to change the active settings group to any one of these settings groups (see *Figure 7.24*).

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Selector Switch Now Rests on Position REMOTE

If the selector switch rests on position REMOTE in *Figure 7.23*, all inputs IN101, IN102, IN103, and IN104 are de-energized and all settings SS1–SS8 in *Table 7.10* are at logical 0. The last active settings group (Group 5 in this example) remains the active settings group (Relay Word bit SG5 = logical 1).

With settings SS1–SS8 all at logical 0, use the serial port **GROUP** command or the front-panel GROUP menu to switch the active settings group from Group 5, in this example, to another desired settings group. The timing is shown in *Figure 7.24*.
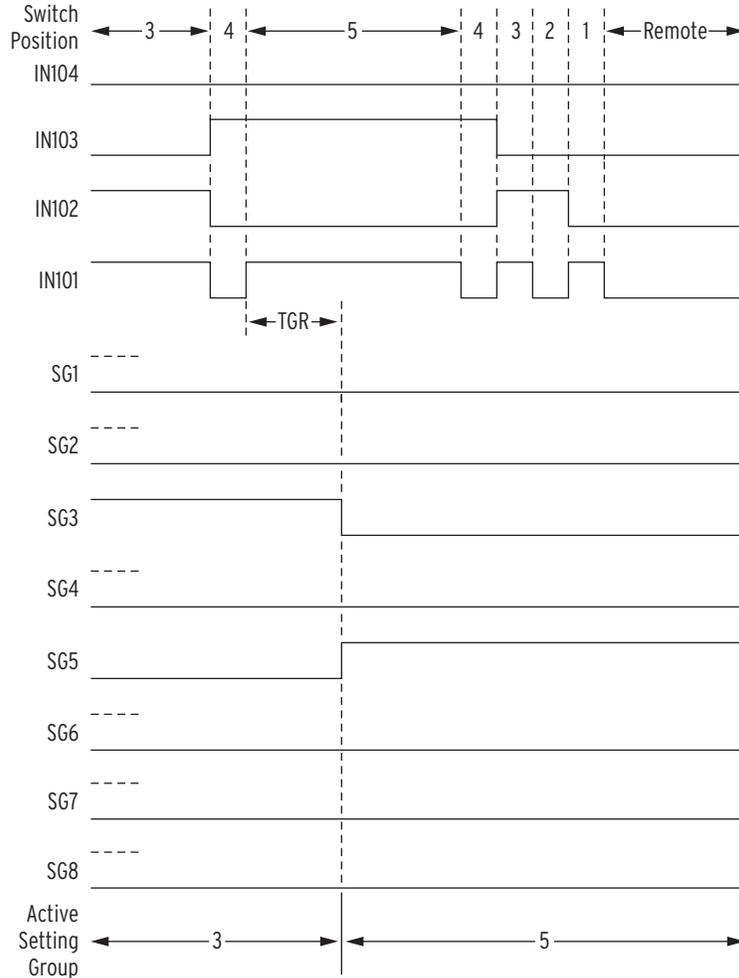
Figure 7.24   Active Settings Group Switching (With Rotating Selector Switch) Time Line

Active Setting: Nonvolatile State

Power Loss

The active settings group is retained if power to the relay is lost and then restored. If a particular settings group is active (e.g., Settings Group 5) when power is lost, the same settings group is active when power is restored.

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Settings Change

If individual settings are changed for the active settings group or one of the other settings groups, the active settings group is retained, much like in the preceding explanation.

If individual settings are changed for a settings group other than the active settings group, there is no interruption of the active settings group, so the relay is not momentarily disabled.

If the individual settings change causes a change in one or more SELOGIC control equation settings SS1–SS8, the active settings group can be changed, subject to the newly enabled SS1–SS8 settings.

Make Active Settings Group Switching Settings With Care

The active settings group is stored in nonvolatile memory so it can be retained during power loss or settings change. The nonvolatile memory is rated for a finite number of writes for all settings group changes. Exceeding the limit can result in a FLASH self-test failure. **An average of four (4) settings group changes per day can be made for a 25-year relay service life**.

This requires that SELOGIC control equation settings SS1–SS8 be set with care. Settings SS1–SS8 must not result in continuous cyclical changing of the active settings group. Time setting TGR qualifies settings SS1–SS8 before changing the active settings group.

Trip and Close Mapping and Output Logic

Figure 7.25 and *Figure 7.26* contain the trip and close mapping and output logic that the SEL-651R-2 uses when connected to various reclosers (see *Section 2* figure references within *Figure 7.25* and *Figure 7.26* for the corresponding reclosers).

① See Figure 2.50 and Figure 2.60
② See Figure 2.66
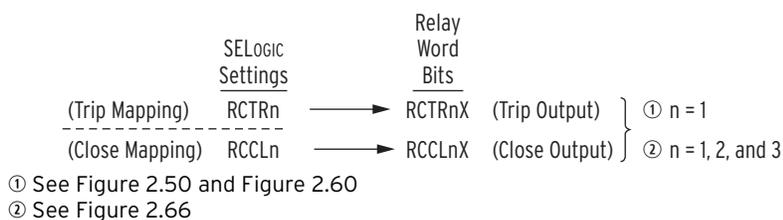
Figure 7.25   Trip and Close Mapping and Output Logic

Note that in *Figure 7.26* there is a rising-edge detect on the RCCL*n* input into gate AND 2. This prevents standing close conditions.

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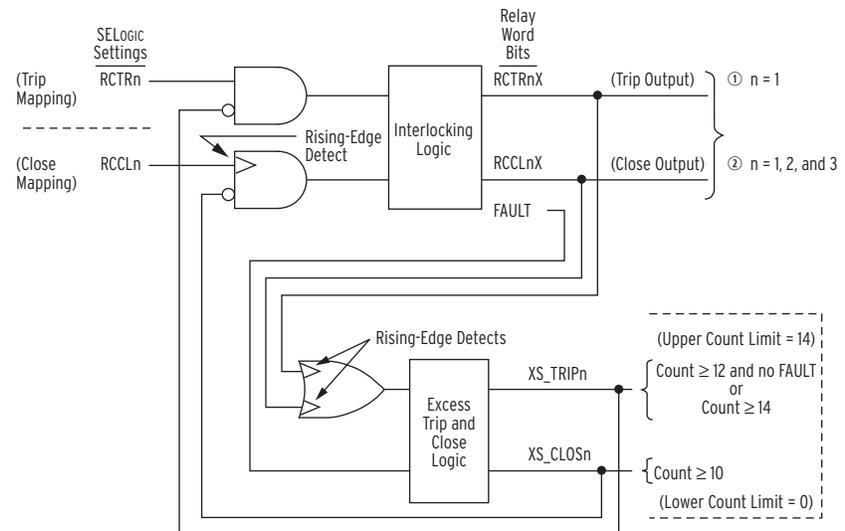
① See Figure 2.73.
② See Figure 2.53, Figure 2.56, Figure 2.63, Figure 2.69, Figure 2.72, and Figure 2.79.

Figure 7.26   Trip and Close Mapping and Output Logic With Interlocking Logic and Excess Trip and Close Logic

The term mapping in the preceding discussion refers to providing a transition between the A-B-C power system world outside the SEL-651R-2 and the A-B-C algorithm world inside the SEL-651R-2, as detailed in *Figure 9.26–Figure 9.28* and the accompanying text.

Factory Trip- and Close-Mapping Settings

The factory settings for the trip-mapping and close-mapping settings are as follows (see *Figure 5.1* and *Figure 6.1*):

RCTR1 := **TRIP3P OR TRIPA OR TRIPB OR TRIPC**

RCTR2 := **TRIP3P OR TRIPA OR TRIPB OR TRIPC**

RCTR3 := **TRIP3P OR TRIPA OR TRIPB OR TRIPC**

RCCL1 := **CLOSE3P**

RCCL2 := **CLOSE3P**

RCCL3 := **CLOSE3P**

As a conservative approach, all the trip logic outputs from *Figure 5.1* are entered in all preceding factory trip-mapping settings, ensuring three-phase tripping for all reclosers.

Making Three-Phase Recloser Trip- and Close-Mapping Settings

For three-phase reclosers (reclosers that can only trip and close all three phases in unison), the *Figure 5.1* Relay Word Bit outputs TRIPA, TRIPB, and TRIPC in the preceding factory trip-mapping setting RCTR1 are inoperative (Group setting ESPB := N). Thus, the recloser trip settings can be minimized to RCTRn := TRIP3P. The corresponding recloser close settings are already minimized to RCCLn := CLOSE3P.

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Making Single-Phase Recloser Trip- and Close-Mapping Settings

For single-phase reclosers (reclosers that can trip and close all three phases in unison or each phase individually), change the factory trip-mapping settings so that each setting is set to TRIPA, TRIPB, or TRIPC (refer to *Table 9.19*). For example:

RCTR1 := **TRIPA OR TRIP3P**

RCTR2 := **TRIPB OR TRIP3P**

RCTR3 := **TRIPC OR TRIP3P**

Such settings depend on correspondence with the power system, as detailed in *Figure 9.26–Figure 9.28* and accompanying text. Note that in *Figure 5.1* three-phase tripping (SELOGIC settings TR3P and TR3X) also flows through Relay Word Bit outputs TRIPA, TRIPB, and TRIPC.

In the preceding suggested trip settings example and in *Table 9.19*, the TRIP3P value is included in each trip-mapping setting, in case Group setting ESPB is changed between Y and N. As shown in *Figure 5.1*, changing Group setting ESPB changes the enabled Relay Word Bit outputs (switches between TRIP3P and TRIPA, TRIPB, TRIPC). If single-phase tripping is never used (Group setting ESPB:=N), the preceding suggested trip settings can all be minimized to TRIP3P only.

For single-phase reclosers, change the factory close-mapping settings so that each setting is set to CLOSEA, CLOSEB, or CLOSEC (refer to *Table 9.20*). For example:

RCCL1 := **CLOSEA OR CLOSE3P**

RCCL2 := **CLOSEB OR CLOSE3P**

RCCL3 := **CLOSEC OR CLOSE3P**

Such settings depend on correspondence with the power system, as detailed in *Figure 9.26–Figure 9.28* and accompanying text. Note that in *Figure 5.1*, three-phase close conditions other than auto reclose (SELOGIC setting CL3P) do not flow through CLOSEA, CLOSEB, and CLOSEC. Three-phase close conditions other than auto reclose have to be programmed in each SELOGIC setting CLA, CLB, and CLC if single-phase tripping and closing is enabled for the recloser (Group setting ESPB := Y).

In the preceding suggested close settings example and in *Table 9.20*, the CLOSE3P value is included in each close-mapping setting, in case Group setting ESPB is changed between Y and N. As shown in *Figure 6.1*, changing Group setting ESPB changes the enabled Relay Word Bit outputs (switches between CLOSE3P and CLOSEA, CLOSEB, CLOSEC). If single-phase closing is never used (Group setting ESPB:=N), the preceding suggested close settings can all be minimized to CLOSE3P only.

MULTI-RECLOSER INTERFACE

The trip settings in Table 9.19, and close settings in Table 9.20 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93. Also, Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface.

Interlocking Logic

The interlocking logic in *Figure 7.26* prevents Relay Word bit outputs RCTR*n*X and RCCL*n*X from being asserted at the same time. This is critical in situations such as that shown in *Figure 2.53*, where only one of the stacked trip or close FETs can be on at one time; otherwise, a short-circuit between 155 Vdc power and ground would result.

Excess Trip and Close Logic

Relay Word bit outputs XSTRIP*n* and XSCLOS*n* from the excess trip and close logic in *Figure 7.26* operate as feedback to the trip and close mapping logic, respectively, in the same figure. This excess trip and close logic feedback prevents Relay Word Bit outputs RCTR*n*X and RCCL*n*X from asserting too many times within a time period. This restriction prevents overheating of the recloser coils.

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Virtual Bits

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Realistically, such a restriction would most likely take effect during testing or any other time the front-panel **TRIP** and **CLOSE** operator controls are pushed an excessive number of times. Each assertion of trip output RCTRnX or close output RCCLnX is detected by the rising-edge detect inputs of the excess trip and close logic and is considered a count. These counts accumulate in the excess trip and close logic.

Any time the cumulative count increments (for a new trip or close), a 360-cycle timer in the excess trip and close logic starts timing. When the 360-cycle timer times out, the cumulative count decrements one (1) count. If the cumulative count is still greater than zero (0), the 360-cycle timer loads up again and times. When the 360-cycle timer times out, again, the cumulative count decrements one (1) count, again. This process repeats until the cumulative count eventually decrements down to zero (0).

The 360-cycle timer period makes room for one more count (one more trip or close operation) to be added to the cumulative counter every 360 cycles. Any time a new trip or close occurs, the cumulative counter increments and the 360-cycle timer is interrupted, if timing, and loaded up again. Conceivably, if the time period between trip or close operations is less than 360 cycles, the cumulative counter just continues incrementing, with no decrementing, until the cumulative count runs as high as the set limits shown in *Figure 7.26*.

Note that the assertion of XS_CLOSn (excess close for pole n) is at a lesser count (cumulative count = 10) than XS_TRIPn (excess trip for pole n). More trips are allowed, because tripping is a more critical function than closing. If a fault is present (Relay Word bit FAULT asserted), then two additional trip attempts (cumulative count as high as 14, instead of just to 12) are allowed before XS_TRIP is asserted. The 360-cycle timer works at bringing the cumulative count back down.

Virtual Bits

The SEL-651R-2 supports 128 virtual bits, VB001–VB128 for the IEC 61850 protocol.

These Relay Word bits are active only in relays ordered with IEC 61850.

When IEC 61850 is enabled, the relay uses the externally created CID file to define the behavior of these virtual bits (received GOOSE messages can be mapped to these bits).

Once defined, the virtual bits can be used in SELOGIC control equations like any other Relay Word bit.

The CID file also defines what information gets transmitted in GOOSE messages. See *Appendix L: IEC 61850* for details on the IEC 61850 protocol.

Output Contacts

The SEL-651R-2 comes standard with two Form C output contacts (OUT201 and OUT202). An ordering option adds 8 extra output contacts: five Form A (OUT101–OUT105) and three Form C (OUT106–OUT108). See *Figure 7.27* for a definition of the output contact forms.

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Output Contacts

Figure 7.27 Output Contact Forms

Figure 2.9 shows the output contact terminal locations on the SEL-651R-2 control module rear panel. Refer to *Additional Relay Connections on page 2.50* for connector and tightening torque information.

SEL-651R-2 output contacts are normally operated through the use of SELOGIC control equation OUT*n* (*n* = 101–108, 201–202) or one of several other methods.

These two methods are ordinarily only used in testing:

➤ SEL ASCII command **PULSE** as described in *Section 10: Communications*.

➤ Front-panel HMI Control menu and Output Contacts submenu as described in *Section 11: Front-Panel Operations*.

Figure 7.28 shows the example operation of Relay Word bits that in turn control corresponding output contacts. Output contacts OUT103–OUT106 are not shown in *Figure 7.28*, but are Form A type output contacts that operate similarly to output contacts OUT101 and OUT102.

SELOGIC control equation settings OUT*n* and serial port ASCII commands PULSE OUT*n* are shown as inputs into the logic in *Figure 7.28*. Front-Panel HMI, not shown in *Figure 7.28*, has the same logical effect as the serial port ASCII commands PULSE OUT*n* in *Figure 7.28*—it is just a different means to the same result (assertion of Relay Word bit OUT*n*).

SCADA Operation

The following methods can be used to operate output contacts via SCADA.

➤ Fast Operate commands as described in *Appendix C: Compressed ASCII Commands*.

➤ DNP3 Objects 10 and 12 as described in *Appendix E: DNP3 Communications*.

➤ Modbus Function code 05h as described in *Appendix K: Modbus RTU and TCP Communications*.

All three methods must first be programmed by using SELOGIC control equation OUT*n* (*n* = 101–108, 201–202). For example, remote bit RB01 may be used to control output OUT202 with the setting OUT202 := RB01. See *Remote Bits on page 7.22*. Modbus Function Code 05h may also directly control the output.

Output Contact Operation

The assertion of a Relay Word bit causes the energization of the corresponding output contact coil. Depending on the contact type (Form A or Form B), the output contact closes or opens. A Form A output contact is open when the output contact coil is de-energized and closed when the output contact coil is energized. A Form B output contact is closed when the output contact coil is de-energized and open when the output contact coil is energized.

Notice that *Figure 7.28* shows all four possible combinations of output contact coil states (energized or de-energized) and output contact types (Form A or Form B).

Only OUT201 is used in the SEL-651R-2 factory-default settings, and it functions as an alarm contact.

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Example SELᴏɢɪᴄ Control Equations

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The default settings are as follows:

OUT101–OUT108 := **0**

OUT201 := **NOT (SALARM OR HALARM)**

OUT202 := **0**

The output SELᴏɢɪᴄ equations are located in the logic settings class (see *Output Contact SELOGIC Equations on page SET.52*).

In most applications, monitor the normally closed side of the Form C contact (OUT201) for fail-safe alarm operation. When the SEL-651R-2 is not enabled (for example, if ac power and the battery are not connected), the normally closed contact would be in the closed position, indicating the alarm condition. When the SEL-651R-2 is powered-up and operational, the normally closed contact would be open, indicating a nonalarm condition.
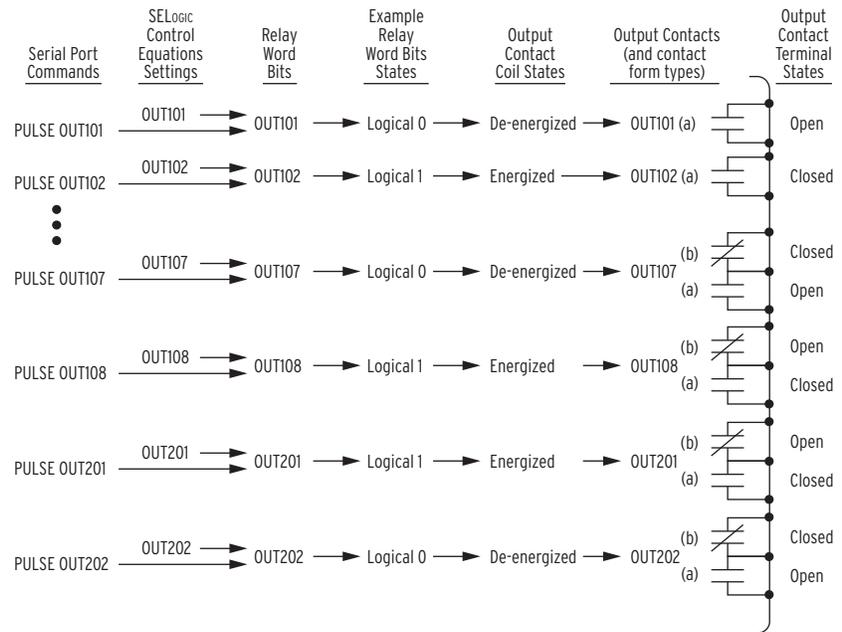
Figure 7.28   Logic Flow for Example Output Contact Operation

If an ac transfer switch is installed, the Form B side of output contact OUT202 is wired to its control circuit (see *Figure 2.38*). This is done in case any future transfer switch control is needed. From the factory, no control is set for output contact OUT202 (see preceding factory-default output contact settings).

Example SELᴏɢɪᴄ Control Equations

Tripping

If tripping does not involve single-pole or switch-onto-fault trip logic, the SELᴏɢɪᴄ control equation trip setting TR3P is the only trip setting needed (see *Trip Logic on page 5.1*).

Note that *Figure 5.1* appears quite complex. Because tripping does not involve single-pole or switch-onto-fault trip logic in this example, however, the only effective inputs in *Figure 5.1* are SELᴏɢɪᴄ control equation trip settings TR3P and TR3X.

TR3P := **51PT OR 51G1T OR 50P1 AND SH03P** (fuse-saving example)

TR3X := **0** (not used—set directly to logical 0)

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Example SELogic Control Equations

TRQL3P := **0**

TRSOTF := **0**

ULTR3P := **NOT (51P OR 51G1)**

TRA := **0**

TRB := **0**

TRC := **0**

Analysis of Trip Setting TR3P

Again, the example trip equation is as follows:

TR3P := **51PT OR 51G1T OR 50P1 AND SH03P**

The Relay Word bit definitions are as follows:

51PT	phase time-overcurrent element timed out
51G1T	residual ground time-overcurrent element timed out
50P1	phase instantaneous overcurrent element asserted
SH03P	reclosing relay shot counter at shot = 0

In the trip equation, the AND operator is executed before the OR operators:

50P1 AND SH03P

Element 50P1 can only cause a trip if the three-phase reclosing relay shot counter is at shot = 0. When the reclosing relay shot counter is at shot = 0, Relay Word bit SH03P is in the following state:

SH03P = 1

If maximum phase current is above the phase instantaneous overcurrent element pickup setting 50P1P, Relay Word bit 50P1 is in the following state:

50P1 = 1

With SH03P = 1 and 50P1 = 1, the logical AND operation results in

(50P1 AND SH0) = (1 AND 1) = 1

and an instantaneous trip results. This logic is commonly used in fuse-saving schemes for distribution feeders.

If the reclosing relay shot counter advances to shot = 1 for the reclose that follows the trip, Relay Word bit SH03P is in the following state:

SH03P = 0

If maximum phase current is above the phase instantaneous overcurrent element pickup setting 50P1P for the reoccurring fault, Relay Word bit 50P1 is in the following state:

50P1 = 1

With SH03P = 0 and 50P1 = 1, the logical AND operation results in

(50P1 AND SH03P) = (1 AND 0) = 0

and no trip results from phase instantaneous overcurrent element 50P1.

7.38 SELᴏɢɪᴄ Control Equation Programming
Example SELᴏɢɪᴄ Control Equations

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A trip will eventually result if time-overcurrent element 51PT or 51G1T times out. If residual ground time-overcurrent element 51G1T times out, Relay Word bit 51G1T is in the following state:

51G1T = 1

When shot = 1, SH03P = 0 and the result is:

$$
\begin{aligned}
\text{TR3P} \quad &= \text{(51PT OR 51G1T OR 50P1 AND SH03P)} \\
&= \text{(0 OR 1 OR 1 AND 0)} \\
&= \text{(0 OR 1 OR 0)} \\
&= 1
\end{aligned}
$$

and a time-delayed trip results from residual ground time-overcurrent element 51G1T.

Trip Output Contact

To assert output contact OUT101 to trip a circuit breaker, make the following SELᴏɢɪᴄ control equation output contact setting:

OUT101 := **TRIP3P**

Note that this simple output contact setting example is different from the standard recloser control trip/close output settings discussed in *Trip and Close Mapping and Output Logic on page 7.31*.

Phase Time-Overcurrent Element 51PT

Examine a phase time-overcurrent element as an example of protection element operation via the logic output of Relay Word bits. The following Relay Word bits are the logic outputs of the phase time-overcurrent element:

51P	indication that the maximum phase-current magnitude is above the level of the phase time-overcurrent pickup setting 51PJP or 51PKP
51PT	indication that the phase time-overcurrent element has timed out on its curve
51PR	indication that the phase time-overcurrent element is fully reset

Pickup Indication

If the maximum phase current is at or below the level of the phase time-overcurrent pickup setting 51PJP or 51PKP, Relay Word bit 51P is in state 0.

If the maximum phase current is above the level of the phase time-overcurrent pickup setting 51PJP or 51PKP, Relay Word bit 51P is in state 1.

The 51PT element is either timing on its curve or is already timed out.

Time-Out Indication

If phase time-overcurrent element 51PT is not timed out on its curve, Relay Word bit 51PT is in state 0.

If phase time-overcurrent element 51PT is timed out on its curve, Relay Word bit 51PT is in state 1.

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Reset Indication

If phase time-overcurrent element 51PT is not fully reset, Relay Word bit 51PR is in state 0. The 51PT element is either:

➤ Timing on its curve

➤ Already timed out

➤ Timing to reset (one-cycle reset or electromechanical emulation—see setting 51PRS)

If phase time-overcurrent element is fully reset, Relay Word bit 51PR is in state 1.

Relay Word Bit Applications

Common uses for Relay Word bits 51P, 51PT, and 51PR:

51P	Testing, such as assigning to an output contact for pickup testing, trip unlatch logic.
51PT	Trip logic.
51PR	Testing, such as assigning to an output contact for reset indication.

Processing Order and Processing Interval

The relay elements and logic (and corresponding SELOGIC control equation settings and resultant Relay Word bits) are processed in the order shown in *Table 7.11* (top to bottom). They are processed every quarter-cycle (1/4-cycle) and the Relay Word bit states (logical 1 or logical 0) are updated with each quarter-cycle pass. Thus, the relay processing interval is 1/4-cycle. Once a Relay Word bit is asserted, it retains the state (logical 1 or logical 0) until it is updated again in the next processing interval.

Table 7.11   Processing Order of Relay Elements and Logic (Top to Bottom) (Sheet 1 of 4)

Relay Elements and Logic (related SELOGIC Control Equations listed in parentheses)	Order of Processing of the SELOGIC Control Equations (listed in parentheses) and Relay Word Bits	Reference Instruction Manual Section
Digital Data Acquisition	IN101–IN107, IN201–IN206	*Section 7*
Operator Controls	PB*nn*, PB*nn*_PUL, *nn* = 01, 02, ...,12	*Section 11*
Trip/Close Capacitor Monitor	TCCAP	*Section 2*
Battery Testing and AC Supply	(TESTBATT)	*Section 6, Section 8*
Analog Data Acquisition	IAMET, IBMET, ICMET, INMET	*Appendix F*
Polarizing Voltage	VPOLV	*Section 4*
Received MIRRORED BITS Communications Elements	ROKA, LBOKA, RMB8A–RMB1A, ROKB, LBOKB, RMB8B–RMB1B	*Appendix D*
Virtual Bits From Received GOOSE Message	VB001–VB128	*Appendix L*
Open Breaker Logic (52A) and SW1 Logic	SW1, (52A_3P, 52A_A, 52A_B, 52A_C, 69_YH) 52AA, 52AB, 52AC, 52A3P	*Section 6*
Ground Switch logic	GNDSW	*Section 4*
Run Single-Pole and 3-Pole Open Logic	SPOA, SPOB, SPOC, SPO, 3PO, 50L, 50LA, 50LB, 50LC	*Section 5*

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Table 7.11   Processing Order of Relay Elements and Logic (Top to Bottom) (Sheet 2 of 4)

Relay Elements and Logic (related SELOGIC Control Equations listed in parentheses)	Order of Processing of the SELOGIC Control Equations (listed in parentheses) and Relay Word Bits	Reference Instruction Manual Section
Loss-of-Potential	V1GOOD, DD, LOP	*Section 4*
Fault Identification Logic	FSA, FSB, FSC	*Table F.2*
Load Encroachment	ZLOAD, ZLOUT, ZLIN	*Section 4*
Latch Control Switches (SET*n*, RST*n*, where *n* = 1 to 16)	(SET01–SET32, RST01–RST32), LT01–LT132	*Section 7*
Instantaneous Overcurrent Elements	50A1–50A4, 50B1–50B4, 50C1–50C4, 50P1–50P6, 50A, 50B, 50C, 50G1–50G6, 50Q1– 50Q6, 50N1–50N6	*Section 4*
Voltage Elements	59YA1, 27YA1, 59YA2, 27YA2, 59YB1, 27YB1, 59YB2, 27YB2, 59YC1, 27YC1, 59YC2, 27YC2, 59YAB1, 27YAB1, 59YBC1, 27YBC1, 59YCA1, 27YCA1, 3P27Y, 3P59Y, 59YV1, 59YQ1, 59YN1, 59YN2	*Section 4*
	59ZA1, 27ZA1, 59ZA2, 27ZA2, 59ZB1, 27ZB1, 59ZB2, 27ZB2, 59ZC1, 27ZC1, 59ZC2, 27ZC2, 59ZAB1, 27ZAB1, 59ZBC1, 27ZBC1, 59ZCA1, 27ZCA1, 3P27Z, 3P59Z, 59ZV1, 59ZQ1, 59ZN1, 59ZN2, 27B81	
Directional Elements (E32IV) and Miscellaneous Overcurrent Elements	(E32IV), 32GF, 32GR, 32PF, 32PR, 32QE, 32QF, 32QGE, 32QR, 32VE, F32P, F32Q, F32QG, F32V, R32P, R32Q, R32QG, R32V, 50GF, 50GR, 50P32, 50QF, 50QR	*Section 4*
Second-Harmonic Blocking	(HBL2TC), HBL2AT, HBL2BT, HBL2CT, HBL2T	*Section 4*
Definite-Time Overcurrent Elements	(50P1TC–50P4TC, 50A1TC–50A4TC, 50B1TC–50B4TC, 50C1TC–50C4TC, 50N1TC–50N4TC, 50G1TC–50G4TC, 50Q1TC–50Q4TC), 50P1T–50P4T, 50A1T–50A4T, 50B1T–50B4T, 50C1T–50C4T, 50N1T–50N4T, 50G1T–50G4T, 50Q1T–50Q4T	*Section 4*
Inverse-Time Overcurrent Elements	(51PTC, 51PSW, 51ATC, 51ASW, 51BTC, 51BSW, 51CTC, 51CSW, 51N1TC, 51N1SW, 51N2TC, 51N2SW, 51G1TC, 51G1SW, 51G2TC, 51G2SW, 51QTC, 51QSW), 51AS, 51AR, 51A, 51AT, 51BS, 51BR, 51B, 51BT, 51CS, 51CR, 51C, 51CT,	*Section 4*
	51PS, 51PR, 51P, 51PT, 51N1S, 51N1R, 51N1, 51N1T, 51N2S, 51N2R, 51N2, 51N2T, 51G1S, 51G1R, 51G1, 51G1T, 51G2S, 51G2R, 51G2, 51G2T, 51QS, 51QR, 51Q, 51QT	
Frequency Elements	27B81, FREQOK, 81D1–81D6, 81D1T–81D6T, (81RTC), 81R1T– 81R4T, 81RT	*Section 4*, *Appendix F*
HIF and HIZ Logic	(HIZRST) LRA, LRB, LRC, LR3, 50GHIZ, 50GHIZA	*Section 4*
Synchronism-Check Elements and Vs (BSYNCH)	(BSYNCH), 59VS, 59VP, 59VA, SSLOW, SFAST, SF, 25A1, 25A2	*Section 4*
Power Elements	3PWR1, 3PWR2, 3PWR3, 3PWR4	*Section 4*
SSI Trigger	(SSI_TRIG)	*Section 12*
Trip and Switch-Onto-Fault Logic	(CLMON), SOTFE, (TR3P, TR3X, TRA, TRB, TRC, TRSOTF, ULTR3P, TRQL3P, TRQLA, TRQLB, TRQLC), TRIPA, TRIPB, TRIPC, TRIP3P, SOTFT, DD	*Section 4*, *Section 5*

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Table 7.11 Processing Order of Relay Elements and Logic (Top to Bottom) (Sheet 3 of 4)

Relay Elements and Logic (related SELOGIC Control Equations listed in parentheses)	Order of Processing of the SELOGIC Control Equations (listed in parentheses) and Relay Word Bits	Reference Instruction Manual Section
Close Logic and Reclosing Relay	(CL3P, CLA, CLB, CLC, ULCL3P, ULCLA, ULCLB, ULCLC, 79RI3P, 79RIS3P, 79DTL3P, 79DTL3X, 79DLS3P, 79SKP3P, 79STL3P, 79BRS3P, 79SEQ3P, 79CLS3P, 79RIA, 79RISA, 79DTLA, 79DLSA, 79SKPA, 79STLA, 79BRSA, 79SEQA, 79CLSA, 79RIB, 79RISB, 79DTLB, 79DLSB, 79SKPB, 79STLB, 79BRSB, 79SEQB, 79CLSB, 79RIC, 79RISC, 79DTLC, 79DLSC, 79SKPC, 79STLC, 79BRSC, 79SEQC, 79CLSC), 79SEQA, 79SEQB, 79SEQC, RCSF3P, RCSFA, RCFSB, RCFSC, CFA, CFB, CFC, CF3P, RSTMNA, RSTMNB, RSTMNC, RSTMN3P, OPTMNA, OPTMNB, OPTMNC, OPTMN3P, SH0A, SH0B, SH0C, SH03P, SH1A, SH1B, SH1C, SH13P, SH2A, SH2B, SH2C, SH23P, SH3A, SH3B, SH3C, SH33P, SH4A, SH4B, SH4C, SH43P, 79RSA, 79RSB, 79RSC, 79RS3P, 79CYA, 79CYB, 79CYC, 79CY3P, 79LOA, 79LOB, 79LOC, 79LO3P, CLOSEA, CLOSEB, CLOSEC, CLOSE3P	*Section 6*
Voltage Sag/Swell/Interruption Elements	SAGA, SAGB, SAGC, SAG3P, SWA, SWB, SWC, SW3P, INTA, INTB, INTC, INT3P	*Section 4*
SELOGIC Variables and counters	(SV01–SV64, SC01R–SC16R, SC01LD–SC16LD, SC01CU–SC16CU, SC01CD–SC16CD) SV01T–SV64T, SC01QU–SC16QU, SC01QD–SC16QD	*Section 7*
Fault Detector for Target Logic and Metering (FAULT)	(FAULT)	*Section 5*
Settings Group Control (SS1–SS8)	(SS1–SS8), SG1–SG8	*Section 7*
Breaker Monitor (BKMON, BKCLS)	(BKMON3P, BKMONA, BKMONB, BKMONC), BCWA, BCWB, BCWC, BCW	*Section 8*
Target Logic (involved phase)	PHASE_A, PHASE_B, PHASE_C	*Section 5*
Target Logic Equations	(TLED_01 – TLED_24)	*Section 5*
Event Report Triggering Equations	(ER, HIFER)	*Section 12*
High-Impedance Fault SELOGIC Settings	(HIFMODE, HIFFRZ, HIFITUNE)	*Section 4*
Trip/Close Outputs	(RCTR1, RCTR2, RCTR3, RCCL1, RCCL2, RCCL3), RCTR1X, RCCL1X, RCTR2X, RCCL2X, RCTR3X, RCCL3X, XS_TRIP1, XS_CLOS1, XS_TRIP2, XS_-CLOS2, XS_TRIP3, XS_CLOS3	*Section 2*, *Section 7*
Reset Equations	(RSTTRGT, RST_DEM, RST_PDM, RST_BK, RST_HIS, RSTENE, RST_MML, RST_HAL)	*Section 5*, *Section 8*, *Section 9*, *Appendix E*
Software Alarm Equation	(SALARM)	*Section 9*
Transmit MIRRORED BITS Communications (TMB1A–TMB8A, TMB1B–TMB8B)	(TMB1A–TMB8A, TMB1B–TMB8B)	*Appendix D*
Contact Outputs	(OUT101–OUT108, OUT201–OUT202), OUT101–OUT108, OUT201–OUT202	*Section 7*
PMU Trigger Equations (TREA1–4, PMTRIG)	(PMTRIG, TREA1–4)	*Appendix J*
Trip, Target LEDs	TRIPLED, TLED_01–TLED_24	*Section 5*, *Section 11*
PMU Status	PMDOK	*Appendix J*
HIZ fault detection	HIFREC	*Section 4*

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Table 7.11 Processing Order of Relay Elements and Logic (Top to Bottom) (Sheet 4 of 4)

Relay Elements and Logic (related SELᴏɢɪᴄ Control Equations listed in parentheses)	Order of Processing of the SELᴏɢɪᴄ Control Equations (listed in parentheses) and Relay Word Bits	Reference Instruction Manual Section
Clear Target Reset and Pulsed Pushbutton Elements	TRGTR, PB01_PUL–PB12_PUL	*Section 5*, *Section 11*
Ethernet Link Status	LINK5, LINK5A, LINK5B, LNKFAIL, P5ASEL, P5BSEL	*Section 10*

Table 7.12 is processed separately from the list in *Table 7.11*. They can be thought of as being processed just before (or just after) *Table 7.11*.

Table 7.12 Asynchronous Processing Order of Relay Elements

Relay Elements and Logic (related SELᴏɢɪᴄ Control Equations listed in parentheses)	Order of processing of the SELᴏɢɪᴄ Control Equations (listed in parentheses) and Relay Word Bits	Reference Instruction Manual Section
Voltage Input Configuration	VSELY, VSELZ	*Section 9*
Demand Ammeters	QDEM, GDEM, NDEM, PDEM	*Section 8*
IRIG-B and Synchrophasor Status	TIRIG, TSOK, TQUAL1–TQUAL4, DST, DSTP, LPSECP, LPSEC	*Appendix J*
Simple Network Time Protocol Status	TSNTPP, TSNTPB	*Section 10*
Mɪʀʀᴏʀᴇᴅ Bɪᴛꜱ Communications Element Status	RBADA, CBADA, RBADB, CBADB	*Appendix D*
Breaker Remote Control Bits	OC3, OCA, OCB, OCC, CC3, CCA, CCB, CCC	*Section 10*
Local Control Switches	LB01–LB16	*Section 7*
Remote Control Switches	RB01–RB32	*Section 7*
Test Database command	TESTDB	*Section 10*
Target Reset	TRGTR	*Section 5*
Alarm processing	HALARM, HALARML, HALARMP, HALARMA, BADPASS, CHGPASS, GRPSW, SETCHG, ACCESS, ACCESSP, PASNVAL	*Section 7*, *Section 13*
Battery Charger	DISTST, CHRGG, DISCHG, BTFAIL, TOSLP	*Section 8*

Section 8

Metering and Monitoring

Introduction

The SEL-651R-2 Recloser Control includes extensive metering features and monitoring functions. The metering functions facilitate power system planning and operation, while the monitoring functions aid in maintenance planning and electrical load forecasting.

The metering functions include:

➤ *Fundamental (Instantaneous) Metering on page 8.2*

➤ *Demand Metering on page 8.6*

➤ *Energy Metering on page 8.15*

➤ *Maximum/Minimum Metering on page 8.17*

➤ *Harmonics and True RMS Metering on page 8.21*

➤ *Synchrophasor Metering on page 8.22*

➤ *High-Impedance Fault Metering on page 8.23*

The monitoring functions include:

➤ *Breaker/Recloser Contact Wear Monitor on page 8.23*

➤ *Battery System Monitor on page 8.39*

➤ *Load Profile Report on page 8.44*

This section explains each of these features.

Dependence on Y and Z Voltage Inputs, Phase Connection Settings, and Scaling

The SEL-651R-2 is configured with six voltage inputs, labeled V1Y, V2Y, V3Y (called the "Y-side"); and V1Z, V2Z, V3Z (called the "Z-side"). Global settings determine which voltage(s) are used for the metered quantities that involve a voltage signal. Additionally, global current and voltage connection settings allow phase rolling of the current and voltage inputs (see *Current and Voltage Connections (Global Settings) on page 9.28*).

All metering and monitoring functions use the rolled voltages and currents, and the voltage signal names become VAY, VBY, VCY, VAZ, VBZ, and VCZ.

All metering functions are calculated in primary quantities, as determined by the CTR, CTRN, PTRY, and PTRZ Group settings. See *Settings Explanations on page 9.27* for details on these ratio settings.

Table 8.1 lists the metering quantities and which of the Global settings affect them.

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Table 8.1   Metering Quantities Affected by Global Settings CTPOL, EPHANT, VSELECT, or FSELECT

Quantity	Affected by Global Settings:	Effect
Fundamental Current:		
Instantaneous	CTPOL (CT polarity)	Phase angle—180-degree shift
Demand	None	Not affected
Peak demand	None	Not affected
RMS Current	None	Not affected
Fundamental Voltage:		
Instantaneous	EPHANT (Phantom voltage enable)	Generate balanced three-phase phantom voltages from one voltage terminal
RMS Voltage	None	Not affected
Sequence Components:		
Voltage	EPHANT	Shutdown calculations for terminals that have EPHANT enabled
Frequency:		
System Frequency	FSELECT (Frequency source selection)	Voltage channel (V1Y, V2Y, or V3Y for FSELECT = VY; V1Z, V2Z, or V3Z for FSELECT = VZ) for frequency measurement
Power:		
Instantaneous	CTPOL, EPHANT or VSELECT	Power direction and voltage source
Power Factor	CTPOL, EPHANT or VSELECT	Power direction and voltage source
Demand	CTPOL, EPHANT or VSELECT	Power direction and voltage source
Peak Demand	CTPOL, EPHANT or VSELECT	Power direction and voltage source
Average Power:		
Real	CTPOL, VSELECT	Power direction and voltage source
Energy:		
Real	CTPOL, EPHANT or VSELECT	Power direction and voltage source
Reactive	CTPOL, EPHANT or VSELECT	Power direction and voltage source
Total Harmonic Distortion:		
Currents	None	Not affected
Voltages	None	Not affected
Harmonics:		
Currents	None	Not affected
Voltages	None	Not affected

Fundamental (Instantaneous) Metering

Description

The SEL-651R-2 performs current, voltage, symmetrical component, and power metering through use of the fundamental (filtered) signals obtained from the same cosine filter that is used in the protective relay algorithms. These values respond to the fundamental signal at the measured system frequency, which is usually near 50 Hz or 60 Hz. Frequency tracking ensures that frequency variations do not adversely affect metering accuracy.

The fundamental metering function updates the metering values approximately twice per second.

The SEL-651R-2 converts the metered values to primary units by using the current transformer ratio settings (CTR and CTRN) and potential transformer ratio settings (PTRY and PTRZ). The PTRY setting is entered in an adjusted

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fashion when low-energy analog (LEA) inputs are present, as described in *Potential Transformer (PT) Ratios (Group Settings) on page 9.42*. If LEA inputs are in use, the actual primary to secondary ratio of the voltage divider must be scaled down before entry as the PTRY setting.

The metered values are available in several forms:

> ➤ Serial port ASCII communications (see *MET Command (Metering Data) on page 10.57*)

> ➤ Serial port Fast Meter communications (see *Appendix C: Compressed ASCII Commands)*

> ➤ Serial port DNP3 (see *Reference Data Map on page E.30*)

> ➤ Front-panel LCD (see *Front-Panel Menus and Screens on page 11.4)*

Appendix G: Analog Quantities lists certain meter values that are available for:

> ➤ Display points (see *Rotating Display on page 11.13*)

> ➤ Load Profile Recorder (see *Load Profile Report on page 8.44*)

Table 7.2 lists certain meter values that are available for:

> ➤ SELOGIC Analog Comparisons (see *Analog Quantities on page 7.2*)

See *Specifications on page 1.9* for a listing of the fundamental metering accuracy in the SEL-651R-2.

These fundamental quantities are used in the Instantaneous Metering quantities, as well as the Demand, Energy, and Maximum/Minimum Metering functions, described later in this section.

Because the fundamental quantities are filtered to the power system frequency, they are immune to signal energy at dc and harmonic frequencies.

Harmonics and True RMS Metering on page 8.21, use the full signal spectrum (except dc) in the calculations. RMS metering quantities may differ from fundamental metering quantities if the system contains harmonic energy.

Effect of Global Settings EGNDSW, EPHANT, VSELECT, FSELECT, and METHRES on Fundamental Metering Functions

Ground Switch Option

GLOBAL SETTING EGNDSW
See Ground Switch Logic on page 4.76.

NOTE: Harmonics and rms metering functions are not affected by the EGNDSW setting.

Global setting EGNDSW is normally set to Y in the SEL-651R-2. This enables the ground switch logic for protection functions and fundamental current metering functions.

In fundamental metering, setting ENGDSW affects how the IG quantity is derived and how it relates to the IN and 3I0 quantities. These quantities (IN, 3I0, IG) are available in the various metering output formats, such as the serial port **MET** command.

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Fundamental Metering When EGNDSW := Y

Use this selection when the neutral current input channel IN is wired residually (see *Figure 2.49* and *Figure 2.52* for sample configurations) and measures the zero-sequence current of the power system. The IA, IB, and IC current inputs are also capable of measuring the zero-sequence current, $3I0 = IA + IB + IC$.

Because the IN channel is more sensitive to small currents, it is more accurate for metering measurements. When currents are higher than the range of the IN channel, the 3I0 quantity is more accurate, because the IN channel will saturate.

Therefore, in the SEL-651R-2 fundamental metering subsystem, quantity IG is automatically switched between IN and 3I0, depending on the present size of the signal being measured. This is similar to the behavior of the IG quantity used in the overcurrent elements 50G1, 51G2, etc., when EGNDSW := Y.

If the current transformer ratio setting for the IN channel (CTRN) is different than the phase channels IA, IB, and IC (CTR), the proper ratio is used for each signal and the IG quantity is truly representing primary amperes.

Thus, when EGNDSW := Y, fundamental metering quantity IG will exactly match IN for small signals and 3I0 for large signals.

Fundamental Metering When EGNDSW := N

Use this selection when the neutral current input channel IN is not connected, or is not connected to a current source related to the phase channels IA, IB, IC.

In this mode, current input channel IN is not coupled with the fundamental metering quantity IG. Thus, when EGNDSW := N, fundamental metering quantity IG matches 3I0 at all times.

Phantom Voltage Function

A phantom setting allows three-phase voltages to be generated from a single metered quantity and the power quantities to be calculated from the generated voltages. The single-phase voltage must be connected to terminal V1Y or V1Z.

Global setting VYCONN or VZCONN is set as shown in *Table 8.2*, depending on the connected voltage signals. The magnitude adjustment factor is 1 for phase-to-neutral signals, and $1/(\sqrt{3})$ to convert phase-to-phase signals to phase-to-neutral signals.

Table 8.2 Phantom Voltage Adjustments (Sheet 1 of 2)

Voltage Connected V1Y-N or V1Z-N (Becomes "Reference" Voltage)	Setting VYCONN or VZCONN	Magnitude and Phase Displacement Adjustment, Multiplied By Reference Voltage to Create V$_{phnt}$	
		Systems With ABC Rotation	Systems With ACB Rotation
V$_A$	A	$1\angle 0°$	$1\angle 0°$
V$_B$	B	$1\angle 120°$	$1\angle(-120)°$
V$_C$	C	$1\angle(-120)°$	$1\angle 120°$
V$_{AB}$	AB	$\dfrac{1}{\sqrt{3}}\angle -30°$	$\dfrac{1}{\sqrt{3}}\angle 30°$

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Table 8.2 Phantom Voltage Adjustments (Sheet 2 of 2)

Voltage Connected V1Y-N or V1Z-N (Becomes "Reference" Voltage)	Setting VYCONN or VZCONN	Magnitude and Phase Displacement Adjustment, Multiplied By Reference Voltage to Create V_{phnt}	
		Systems With ABC Rotation	Systems With ACB Rotation
V_{BC}	BC	$\frac{1}{\sqrt{3}} \angle 90°$	$\frac{1}{\sqrt{3}} \angle -90°$
V_{CA}	CA	$\frac{1}{\sqrt{3}} \angle -150°$	$\frac{1}{\sqrt{3}} \angle 150°$

The phantom voltage V_{phnt} signal created using *Table 8.2* is labeled as VAY or VAZ, depending on the EPHANT setting. The recloser control derives B- and C-phase signals by rotating V_{phnt} by either 120 or –120, depending on the phase rotation setting PHROT.

Figure 8.1 shows an example of the phantom voltage function with ABC phase rotation.

NOTE: Phantom voltages can only be enabled on one set of terminals at a time.
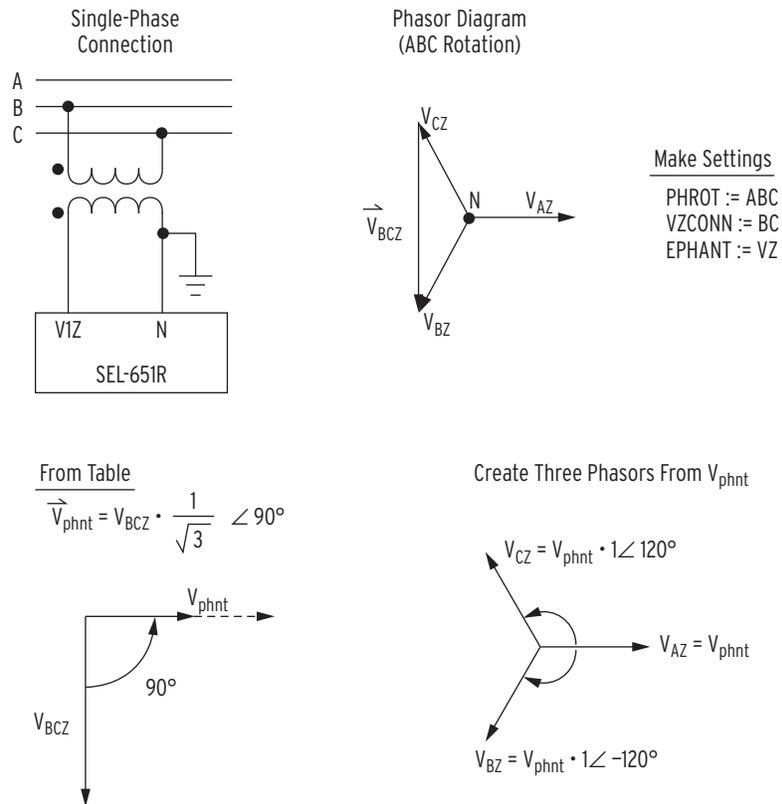
Figure 8.1   Example Phasor Diagram of Phantom Voltage Adjustment

When the phantom voltage option is being used (i.e., EPHANT is set to VY or VZ), the fundamental power and energy quantities are based on the derived phantom voltages.

When the phantom voltage option is being used (i.e., EPHANT is set to VY or VZ), symmetrical components (positive-, negative-, and zero-sequence voltages) are not calculated. In the example shown in *Figure 8.1*, EPHANT := VZ, thus V1Z, V2Z, and 3V0Z are set to zero internally, and they

NOTE: The phantom voltage settings have no effect on the protection elements in the SEL-651R-2. See Voltage Elements on page 4.31.

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are not displayed in the **MET** command. These values are hidden because they would look like a perfectly balanced three-phase system, which may be misleading.

Phantom Voltage Option Not in Service

If phantom voltage generation is not enabled (i.e., EPHANT := OFF) and three-phase voltages are connected, Global setting VSELECT selects the voltage input terminals (VY or VZ) that are used to calculate power and energy quantities.

If Global setting VSELECT := OFF when EPHANT := OFF, power and energy metering is disabled.

Frequency Measurement Selection

Global setting FSELECT determines the voltage input terminal that is used to measure frequency. This setting is unaffected by the phantom voltage setting (see *Frequency Source Selection Setting (FSELECT) on page 9.33*).

METHRES Setting

The relay applies a small-signal cutoff threshold to the voltage and current signals, which may affect subsequent uses of the measurement (see *Small-Signal Cutoff for Metering on page 8.19*).

Demand Metering

The SEL-651R-2 offers the choice between two types of demand metering, settable with the Group setting:

EDEM := **THM** Thermal Demand Meter

or

EDEM := **ROL** Rolling Demand Meter

The demand metering settings (see *Table 8.3*) are available via the **SET** command (see *Table 9.1* and also *Settings Sheet page SET.9* at the end of *Section 9*). Also refer to *MET Command (Metering Data) on page 10.57* and *MET D (Demand Metering) on page 10.59*.

The SEL-651R-2 provides demand and peak demand metering for the following values:

Currents

$I_{A,B,C,N}$ Input currents (A primary)

I_G Ground Current (A primary; IG = IN or 3I0, see *Ground Switch Option on page 8.3*)

$3I_2$ Negative-sequence current (A primary)

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If three-phase voltage signals are connected and the Global settings VYCONN, VZCONN, EPHANT, and VSELECT are properly made, the SEL-651R-2 provides demand metering for the following values:

Power

$MVA_{A,B,C,3P}$		Single-phase and three-phase megavolt-amperes, primary
$MW_{A,B,C,3P}$	IN	Single-phase and three-phase megawatts, primary
$MW_{A,B,C,3P}$	OUT	Single-phase and three-phase megawatts, primary
$MVAR_{A,B,C,3P}$	IN	Single-phase and three-phase megavars, primary
$MVAR_{A,B,C,3P}$	OUT	Single-phase and three-phase megavars, primary

where IN and OUT correspond to the standard relay convention of OUT for positive power, and IN for negative power. Global setting CTPOL can change the direction of power (and energy) metering (see *Table 8.1*).

If a single-phase voltage is connected, and the settings VYCONN, VZCONN, and EPHANT are properly made, the same demand values are available by using the phantom voltage feature (see *Fundamental (Instantaneous) Metering on page 8.2*). Power demand metering accuracy degrades when the phantom feature is used. The accuracy error is proportional to the amount of system load unbalance and the zero-sequence source impedance.

Depending on enable setting EDEM, these demand and peak demand values are thermal demand or rolling demand values. The differences between thermal and rolling demand metering are explained in the following subsection.

Comparison of Thermal and Rolling Demand Meters

The example in *Figure 8.2* shows the response of thermal and rolling demand meters to a step current input. The current input is at a magnitude of zero and then suddenly goes to an instantaneous level of 1.0 per unit (a "step").

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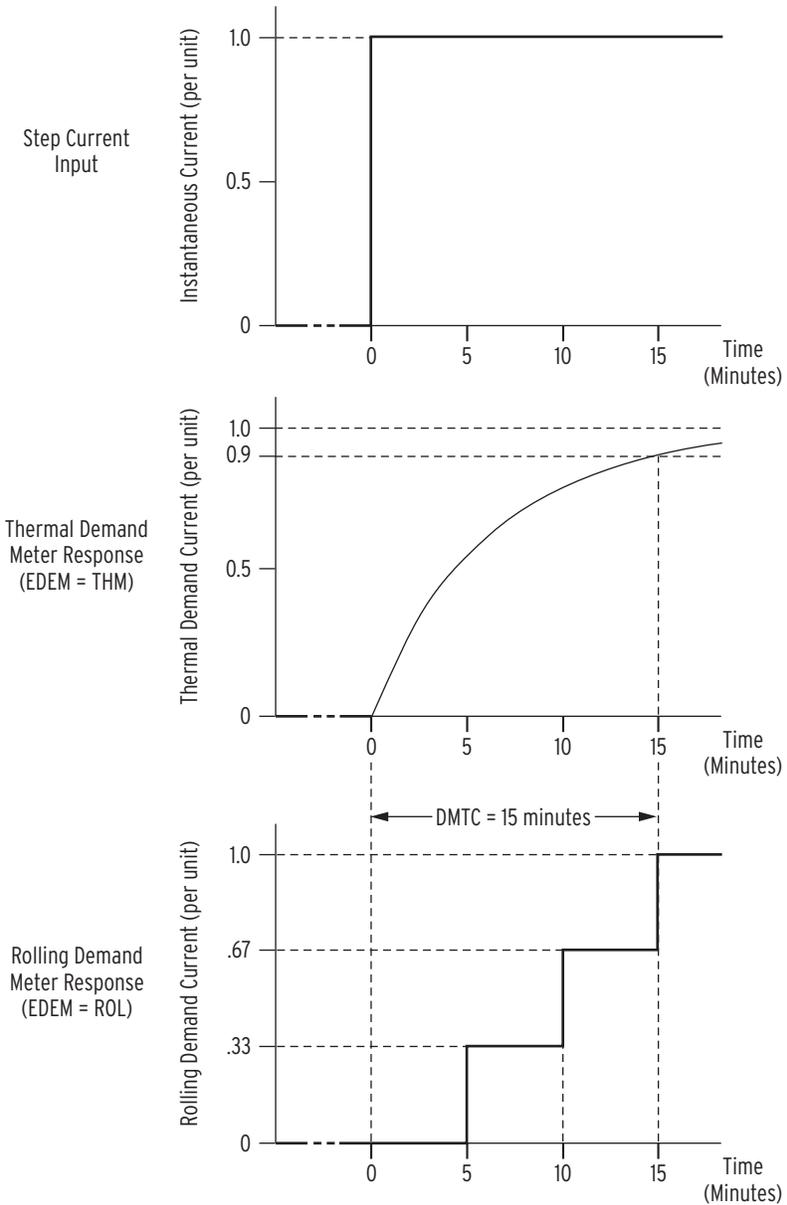
Figure 8.2 Response of Thermal and Rolling Demand Meters to a Step Input (Setting DMTC = 15 Minutes)

Thermal Demand Meter Response (EDEM := THM)

The response of the thermal demand meter in *Figure 8.2* (middle) to the step current input (top) is analogous to the series RC circuit in *Figure 8.3*.
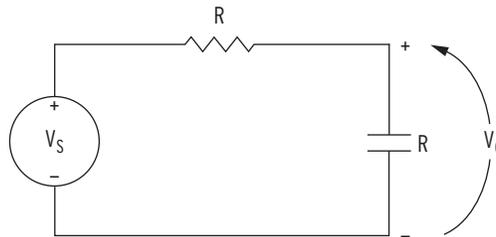
Figure 8.3 Voltage V_S Applied to Series RC Circuit

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In the analogy:

Voltage V_S in *Figure 8.3* corresponds to the step current input in *Figure 8.2* (top).

Voltage V_C across the capacitor in *Figure 8.3* corresponds to the response of the thermal demand meter in *Figure 8.2* (middle).

If voltage V_S in *Figure 8.3* has been at zero ($V_S = 0.0$ per unit) for some time, voltage V_C across the capacitor in *Figure 8.3* is also at zero ($V_C = 0.0$ per unit). If voltage V_S is suddenly stepped up to some constant value ($V_S = 1.0$ per unit), voltage V_C across the capacitor starts to rise toward the 1.0 per unit value. This voltage rise across the capacitor is analogous to the response of the thermal demand meter in *Figure 8.2* (middle) to the step current input (top).

NOTE: The examples in this section discuss demand current, but MVA, MW, and MVAR demand values are also available, as stated at the beginning of this subsection.

In general, because voltage V_C across the capacitor in *Figure 8.3* cannot change instantaneously, the thermal demand meter response is not immediate either for the increasing or decreasing applied instantaneous current. The thermal demand meter response time is based on the demand meter time constant setting DMTC (see *Table 8.3*). Note in *Figure 8.2*, the thermal demand meter response (middle) is at 90 percent (0.9 per unit) of full applied value (1.0 per unit) after a time period equal to setting DMTC := 15 minutes, referenced to when the step current input is first applied.

The SEL-651R-2 updates thermal demand values approximately every 2 seconds.

Rolling Demand Meter Response (EDEM := ROL)

The response of the rolling demand meter in *Figure 8.2* (bottom) to the step current input (top) is calculated with a sliding time-window arithmetic average calculation. The width of the sliding time window is equal to the demand meter time constant setting DMTC (see *Table 8.3*). Note in *Figure 8.2*, the rolling demand meter response (bottom) is at 100 percent (1.0 per unit) of full applied value (1.0 per unit) after a time period equal to setting DMTC := 15 minutes, referenced to when the step current input is first applied.

The rolling demand meter integrates the applied signal, such as step current, input in 5-minute intervals. The integration is performed approximately every 2 seconds. The average value for an integrated 5-minute interval is derived and stored as a 5-minute total. The rolling demand meter then averages a number of the 5-minute totals to produce the rolling demand meter response. In the *Figure 8.2* example, the rolling demand meter averages the three latest 5-minute totals because setting DMTC = 15 (15/5 = 3). The rolling demand meter response is updated every 5 minutes, after a new 5-minute total is calculated.

The following is a step-by-step calculation of the rolling demand response example in *Figure 8.2* (bottom).

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Time = 0 Minutes

Presume that the instantaneous current has been at zero for quite some time before "Time = 0 minutes" or that the demand meters were recently reset. The three 5-minute intervals in the sliding time-window at "Time = 0 minutes" each integrate into the following 5-minute totals:

5-Minute Totals	Corresponding 5-Minute Interval
0.0 per unit	–15 to –10 minutes
0.0 per unit	–10 to –5 minutes
0.0 per unit	–5 to 0 minutes
0.0 per unit	

Rolling demand meter response at "Time = 0 minutes" = 0.0/3 = 0.0 per unit.

Time = 5 Minutes

The three 5-minute intervals in the sliding time-window at "Time = 5 minutes" each integrate into the following 5-minute totals:

5-Minute Totals	Corresponding 5-Minute Interval
0.0 per unit	–10 to –5 minutes
0.0 per unit	–5 to 0 minutes
1.0 per unit	0 to 5 minutes
1.0 per unit	

Rolling demand meter response at "Time = 5 minutes" = 1.0/3 = 0.33 per unit.

Time = 10 Minutes

The three 5-minute intervals in the sliding time-window at "Time = 10 minutes" each integrate into the following 5-minute totals:

5-Minute Totals	Corresponding 5-Minute Interval
0.0 per unit	–5 to 0 minutes
1.0 per unit	0 to 5 minutes
1.0 per unit	5 to 10 minutes
2.0 per unit	

Rolling demand meter response at "Time = 10 minutes" = 2.0/3 = 0.67 per unit.

Time = 15 Minutes

The three 5-minute intervals in the sliding time-window at "Time = 15 minutes" each integrate into the following 5-minute totals:

5-Minute Totals	Corresponding 5-Minute Interval
1.0 per unit	0 to 5 minutes
1.0 per unit	5 to 10 minutes
1.0 per unit	10 to 15 minutes
3.0 per unit	

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Rolling demand meter response at "Time = 15 minutes" = 3.0/3 = 1.0 per unit.

Demand Meter Settings

Table 8.3   Demand Meter Settings and Settings Range

Setting	Definition	Range
EDEM	Demand meter type	THM = thermal ROL = rolling
DMTC	Demand meter time constant	5, 10, 15, 30, or 60 minutes
PDEMP	Phase demand current pickup	0.10–3.20 A secondary
NDEMP	Neutral ground demand current pickup[a]	0.005–0.640 A secondary
GDEMP	Ground demand current pickup[b]	0.005–3.200 A secondary
QDEMP	Negative-sequence demand current pickup	0.10–3.20 A secondary

[a] NDEMP is only available when Global setting EGNDSW := N.
[b] GDEMP setting range shown is for factory-default settings, with EGNDSW := Y, and CTR = CTRN := 1000. See Settings Sheet page SET.32 at the end of Section 9 for details.

NOTE: Changing setting EDEM or DMTC resets the demand meter values to zero. This also applies to changing the active settings group, and setting EDEM or DMTC is different in the new active settings group. Demand current pickup settings PDEMP, NDEMP, GDEMP, and QDEMP can be changed without affecting the demand meters.

The demand current pickup settings in *Table 8.3* are applied to demand current meter outputs as shown in *Figure 8.4*. For example, when residual ground demand current $I_{G(DEM)}$ goes above corresponding demand pickup GDEMP, Relay Word bit GDEM asserts to logical 1. Use these demand current logic outputs (PDEM, NDEM, GDEM, and QDEM) to alarm for high loading or unbalance conditions. Use them in other schemes such as the following example.
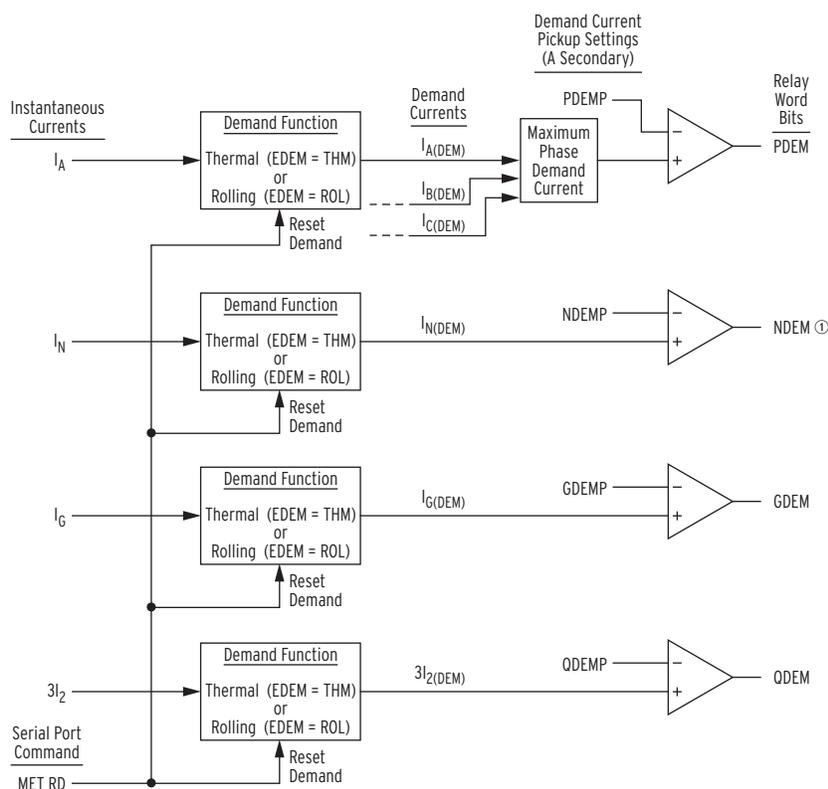
① NDEM is only functional when Global setting EGNDSW := N.

Figure 8.4   Demand Current Logic Outputs

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Demand Current Logic Output Application: Raise Pickup for Unbalance Current

During times of high loading, the residual ground overcurrent elements can see relatively high unbalance current I_G ($I_G = 3I_0$). To avoid tripping on unbalance current I_G, use Relay Word bit GDEM to detect the residual ground (unbalance) demand current $I_{G(DEM)}$ and effectively raise the pickup of the residual ground time-overcurrent element 51G1T. This is accomplished with the following settings from *Table 8.3*, pertinent residual ground overcurrent element settings, and SELOGIC control equation torque-control setting 51G1TC:

EDEM := **THM**

DMTC := **5**

GDEMP := **1.000**

51G1JP := **1.50**

50G5P := **2.30**

51G1TC := **NOT(GDEM) OR GDEM AND 50G5**

51G1SW := **0**

Refer to *Figure 8.4*, *Figure 8.5*, and *Figure 4.22*.
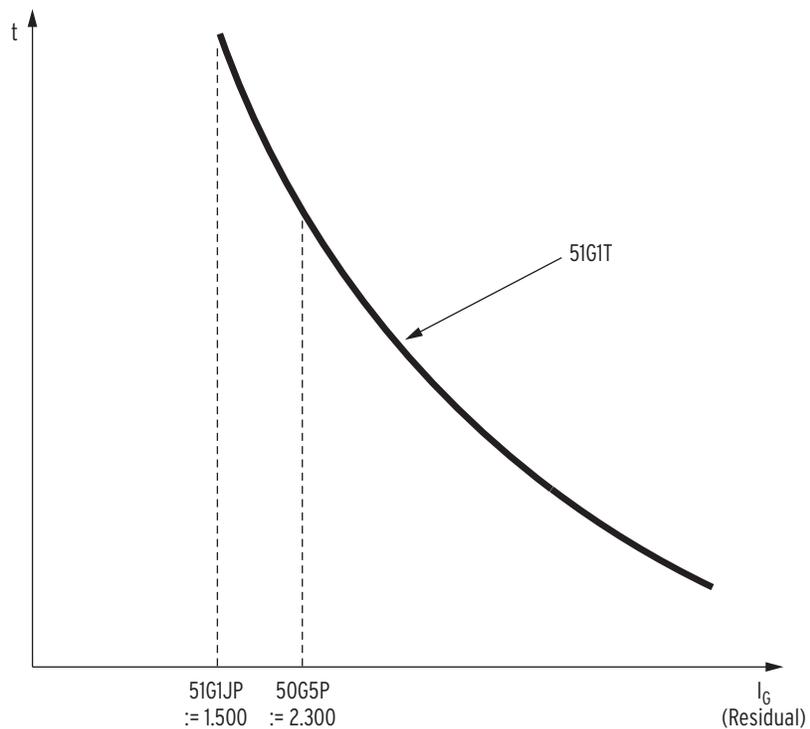
Figure 8.5   Raise Pickup of Residual Ground Time-Overcurrent Element for Unbalance Current

Residual Ground Demand Current Below Pickup GDEMP

When unbalance current I_G is low, unbalance demand current $I_{G(DEM)}$ is below corresponding demand pickup GDEMP = 1.000 A secondary, and Relay Word bit GDEM is deasserted to logical 0. This results in SELOGIC control equation torque-control setting 51G1TC being in the state:

51G1TC := NOT(GDEM) OR GDEM AND 50G5

:= NOT (logical 0) OR (logical 0) AND 50G5

:= logical 1   **Equation 8.1**

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Thus, the residual ground time-overcurrent element 51G1T operates on its standard pickup:

$$51G1JP := 1.500 \text{ A Secondary}$$

<div align="right">**Equation 8.2**</div>

If a ground fault occurs, the residual ground time-overcurrent element 51G1T operates with the sensitivity provided by pickup 51G1JP := 1.500 A secondary. The thermal demand meter, even with setting DMTC = 5 minutes, does not respond fast enough to the ground fault to make a change to the effective residual ground time-overcurrent element pickup—it remains at 1.500 A secondary. Demand meters respond to more slow-moving general trends.

Residual Ground Demand Current Goes Above Pickup GDEMP

When unbalance current I_G increases, unbalance demand current $I_{G(DEM)}$ follows, going above corresponding demand pickup GDEMP = 1.000 A secondary, and Relay Word bit GDEM asserts to logical 1. This results in SELOGIC control equation torque-control setting 51GTC being in the state:

$$51G1TC := NOT(GDEM) \text{ OR GDEM AND 50G5}$$
$$:= NOT \text{ (logical 1) OR (logical 1) AND 50G5}$$
$$:= \text{logical 0 OR 50G5}$$
$$:= 50G5$$

<div align="right">**Equation 8.3**</div>

Thus, the residual ground time-overcurrent element 51G1T operates with an effective, less-sensitive pickup:

$$50G5P := 2.30 \text{ A Secondary}$$

<div align="right">**Equation 8.4**</div>

The reduced sensitivity keeps the residual ground time-overcurrent element 51G1T from tripping on higher unbalance current I_G.

Residual Ground Demand Current Goes Below Pickup GDEMP Again

When unbalance current I_G decreases again, unbalance demand current $I_{G(DEM)}$ follows, going below corresponding demand pickup GDEMP = 1.000 A secondary, and Relay Word bit GDEM deasserts to logical 0. This results in SELOGIC control equation torque-control setting 51G1TC being in the state:

$$51G1TC := NOT(GDEM) \text{ OR GDEM AND 50G5}$$
$$:= NOT \text{ (logical 0) OR (logical 0) AND 50G5}$$
$$:= \text{logical 1}$$

<div align="right">**Equation 8.5**</div>

Thus, the residual ground time-overcurrent element 51G1T operates on its standard pickup again:

$$51G1JP := 1.500 \text{ A secondary}$$

<div align="right">**Equation 8.6**</div>

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View or Reset Demand Metering Information

Via Serial Port

The **MET D** command displays demand and peak demand metering (see *MET Command (Metering Data)*, *MET D (Demand Metering) on page 10.59*).

The **MET RD** command resets the demand metering values. The **MET RP** command resets the peak demand metering values.

After demand values are reset, if setting EDEM := ROL, there may be a delay of as long as two times the DMTC setting before the demand values are updated.

Via Front Panel

The information and reset functions available via the previously discussed serial port commands **MET D**, **MET RD**, and **MET RP** are also available via the front-panel menu (see *Human-Machine Interface on page 11.2*).

Via DNP3 or Modbus

The demand and peak demand metering values are available via DNP3 and Modbus. See the Demand Metering and Peak (Demand) Metering section of *Table G.1*.

The DNP3 binary output DRST_DEM and DRST_PDM can be used to reset the demand metering and peak demand metering, respectively. These controls are similar in function to the **MET RD** and **MET RP** commands. See *Appendix E: DNP3 Communications* for more details.

The Modbus protocol can be used to reset the demand metering and peak demand metering, with functions similar to the **MET RD** and **MET RP** commands. There are two methods available:

➤ Writing to the Reset Demands or Reset Demand Peaks output coil.

➤ Writing a specific analog value to the RSTDAT register.

See *Appendix K: Modbus RTU and TCP Communications* for details.

Via Fast Meter or IEC 61850

The demand and peak demand metering values are available via Fast Meter and IEC 61850. See the Demand Metering and Peak (Demand) Metering section of *Table G.1*.

Reset Via SELOGIC Control Equation

The RST_DEM and RST_PDM SELOGIC control equation settings can be used to reset the demand metering and peak demand metering respectively. The relay resets the function when the setting first asserts (rising edge, e.g., a logical 0 to a logical 1 transition).

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Example Application of RST_DEM and RST_PDM

A control scheme requires:

➤ Demand metering to be reset when control input IN106 asserts, or when SV12T asserts.

➤ Peak demand metering to be reset when control input IN106 asserts, or when remote bit RB14 asserts.

Make the logic settings in the Global settings of the relay:

RST_DEM = **R_TRIG IN106 OR R_TRIG SV12T**

RST_PDM = **R_TRIG IN106 OR R_TRIG RB14**

The "R_TRIG" rising edge operators ensure that a maintained logical 1 on IN106 does not prevent SV12T from resetting the demand metering, and does not prevent RB14 from resetting the peak demand metering.

NOTE: To avoid unexpected clearing of metering data, the proposed SELOGIC control equations should be tested to ensure they do not assert after relay power-up.

Demand Metering Updating and Storage

The SEL-651R-2 updates demand values approximately every two seconds.

The SEL-651R-2 stores peak demand values to nonvolatile storage once per day and overwrites the previous stored value if it is exceeded. Should the recloser control lose control power, it will restore the peak demand values saved by the relay at 23:50 hours on the previous day.

Demand metering peak recording is momentarily suspended when SELOGIC control equation setting FAULT is asserted (= logical 1). See the explanation for the FAULT setting in *Maximum/Minimum Metering Update and Storage on page 8.18*.

Energy Metering

If three-phase voltages signals are connected and the Global settings VYCONN, VZCONN, EPHANT, and VSELECT are properly made, the SEL-651R-2 provides energy metering for the following values:

$MWH_{A,B,C,3P}$	IN	Single-phase and three-phase megawatt-hours, primary
$MWH_{A,B,C,3P}$	OUT	Single-phase and three-phase megawatt-hours, primary
$MVARH_{A,B,C,3P}$	IN	Single-phase and three-phase megavolt-ampere reactive hours, primary
$MVARH_{A,B,C,3P}$	OUT	Single-phase and three-phase megavolt-ampere reactive hours, primary

where IN and OUT correspond to the standard relay convention of OUT for positive power, and IN for negative power. Global setting CTPOL can change the direction of energy (and power) metering. See *Table 8.1*.

If a single-phase voltage is connected, and the settings VYCONN, VZCONN, and EPHANT are properly made, the same energy values are available by using the phantom voltage feature (see *Fundamental (Instantaneous) Metering on page 8.2*). Energy metering accuracy degrades when the phantom feature is used. The accuracy error is proportional to the amount of system load unbalance and the zero-sequence source impedance.

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View or Reset Energy Metering Information

Via Serial Port

The **MET E** command displays accumulated single- and three-phase megawatt and megavolt-ampere reactive hours. The **MET RE** command resets the accumulated single- and three-phase megawatt and megavolt-ampere reactive hours (see *MET Command (Metering Data) on page 10.57*, *MET E (Energy Metering) on page 10.60*).

Via Front Panel

The information and reset functions available via the previously discussed serial port commands **MET E** and **MET RE** are also available via the front-panel menu (see *Human-Machine Interface on page 11.2*).

Via DNP3 or Modbus

The energy metering values are available via DNP3 and Modbus. See the Energy Metering section of *Table G.1*.

The DNP3 binary output DRST_ENE can be used to reset the energy metering, and is similar in function to the **MET RE** command (see *Appendix E: DNP3 Communications*).

The Modbus protocol can be used to reset the energy metering, with functions similar to the **MET RE** command. Two methods are available:

➤ Writing to the Reset Energy Data output coil.

➤ Writing a specific analog value to the RSTDAT register.

See *Appendix K: Modbus RTU and TCP Communications* for details.

Via IEC 61850

The energy metering values are available via IEC 61850. See the Energy Metering section of *Table G.1*.

Reset Via SELᴏɢɪᴄ Control Equation

The RST_ENE SELOGIC control equation setting can be used to reset the energy metering. The relay resets the function when the setting first asserts (rising edge, e.g., a logical 0 to a logical 1 transition).

Example Application of RST_ENE

NOTE: To avoid unexpected clearing of metering data, the proposed SELOGIC control equation should be tested to ensure it does not assert after relay power-up.

A control scheme requires energy metering to be reset when control input IN105 asserts, or when SV11T asserts.

Make the logic settings in the Global settings of the relay:

RST_ENE = **R_TRIG IN105 OR R_TRIG SV11T**

The "R_TRIG" rising edge operators ensure that a maintained logical 1 on IN105 does not prevent SV11T from resetting the energy metering.

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Maximum/Minimum Metering

Energy Metering Updating and Storage

The SEL-651R-2 updates energy values approximately every two seconds.

The SEL-651R-2 stores energy values to nonvolatile storage once per day and overwrites the previous stored value. Should the recloser control lose control power, it will restore the energy values saved by the relay at 23:50 hours on the previous day.

Accumulated energy metering values function like those in an electromechanical energy meter. When the energy meter reaches 99999.999 MWh or 99999.999 MVARh, the SEL-651R-2 starts over at zero.

Maximum/Minimum Metering

The SEL-651R-2 includes a Maximum/Minimum metering function that records the excursions of certain fundamental metering quantities (see below). The date and time stamps at which each quantity reached its maximum and minimum value are also reported.

View or Reset Maximum/Minimum Metering Information

Via Serial Port

The **MET M** command displays Maximum/Minimum metering for the following values (see *MET M (Maximum/Minimum Metering) on page 10.61*):

Currents

$I_{A,B,C,N}$	Input currents (A primary)
I_G	Ground Current (A primary; IG = IN or 3I0, see *Ground Switch Option on page 8.3*)

Voltages

V_AY, V_BY, V_CY	Input voltages, Y-terminals (kV primary)
V_AZ, V_BZ, V_CZ	Input voltages, Z-terminals (kV primary)

Power

MW_{3P}	Three-phase megawatts
$MVAR_{3P}$	Three-phase megavolt-amperes reactive
MVA_{3P}	Three-phase megavolt-amperes

NOTE: If Global setting EPHANT := VY, the Y-terminal voltages are replaced by the calculated phantom voltages. Similarly, if EPHANT := VZ, the Z-terminal voltages are replaced by the calculated phantom voltages (see Phantom Voltage Function on page 8.4).

The **MET RM** command resets the Maximum/Minimum metering values.

The MW and MVAR maximum and minimum values can be negative or positive, indicating the range of power flow that has occurred since the last **MET RM** reset command. These functions simulate analog meter drag-hands, with the maximum value representing the upper drag-hand and the minimum value representing the lower drag-hand.

Table 8.4 shows the values that the recloser control would record for various power flow directions (either MW3P or MVAR3P).

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Maximum/Minimum Metering

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Table 8.4   Operation of Maximum/Minimum Metering With Directional Power Quantities

If Power Varies		Recorded MAX	Recorded MIN
From:	To:		
9.7	16.2	16.2	9.7
–4.2	1.4	1.4	–4.2
–25.3	–17.4	–17.4	–25.3
–6.2	27.4	27.4	–6.2

(For simplicity, the date and time stamps are not shown here.)

Via Front Panel

The metering and reset functions available via serial port commands **MET M** and **MET RM** are also available via the front-panel menu (see *Human-Machine Interface on page 11.2*).

Reset Via DNP3 or Modbus Control

The DNP3 binary output DRST_MML can be used to reset the Maximum/Minimum metering, and is similar in function to the **MET RM** command (see *Appendix E: DNP3 Communications*).

The Modbus protocol can be used to reset the Maximum/Minimum metering, with methods that are similar in function to the **MET RM** command. Two methods are available:

➤ Writing to the Reset Max/Min output coil.

➤ Writing a specific analog value to the RSTDAT register.

See *Appendix K: Modbus RTU and TCP Communications* for details.

Reset Via SELᴏɢɪᴄ Control Equation

The RST_MML SELᴏɢɪᴄ control equation setting can be used to reset the Maximum/Minimum metering. The relay resets the function when the setting first asserts (rising edge, e.g., a logical 0 to a logical 1 transition).

Example Application of RST_MML

A control scheme requires Maximum/Minimum metering to be reset when control input IN104 asserts, or when SV10T asserts.

Make the logic settings in the Global settings of the relay:

RST_MML = **R_TRIG IN104 OR R_TRIG SV10T**

The R_TRIG rising edge operators ensure that a maintained logical 1 on IN104 does not prevent SV10T from resetting the energy metering.

NOTE: To avoid unexpected clearing of metering data, the proposed SELᴏɢɪᴄ control equation should be tested to ensure it does not assert after relay power-up.

Maximum/Minimum Metering Update and Storage

The maximum/minimum metering function is intended to reflect normal load variations rather than fault conditions or outages. Therefore, the SEL-651R-2 updates maximum/minimum values only if Global SELᴏɢɪᴄ setting FAULT is deasserted (= logical 0) and has been deasserted for at least 3600 cycles.

The factory-default setting is set with time-overcurrent element pickups:

FAULT := **51P OR 51G1**

If there is a fault, 51P or 51G1 asserts and blocks updating of maximum/minimum metering values.

In addition to FAULT being deasserted for at least 3600 cycles, the following conditions must also be met:

➤ For voltage values V_AY, V_BY, V_CY, V_AZ, V_BZ, and V_CZ, the voltage is above the threshold: 25.0 V secondary (300 V base).

➤ For phase current values I_A, I_B, and I_C, the current is above the threshold: 0.01 A secondary.

➤ For neutral current value I_N, the current is above the threshold: 2 mA secondary.

➤ For ground current value I_G:

All three-phase currents I_A, I_B, and I_C are above threshold.

➤ For power values MW_{3P}, $MVAR_{3P}$, and MVA_{3P}:

All three-phase currents I_A, I_B, and I_C are above threshold, and the required voltages V_AY, V_BY, V_CY, or V_AZ, V_BZ, and V_CZ (depending on the EPHANT or VSELECT Global settings) are above threshold (see *Phantom Voltage Function on page 8.4*).

➤ The metering value is above the previous maximum or below the previous minimum for approximately one second.

The SEL-651R-2 stores maximum/minimum values to nonvolatile storage once per day and overwrites the previous stored value if that is exceeded. If the recloser control loses control power, it will restore the maximum/minimum values saved at 23:50 hours on the previous day.

Note: The values used by the maximum/minimum metering are the same fundamental metering values as used in the instantaneous metering function. The maximum/minimum metering function updates approximately twice per second. These values should be relatively immune to transient conditions.

Small-Signal Cutoff for Metering

Global setting METHRES controls how various metering functions respond when the metered value is small. Set METHRES to Y, N or E as explained below.

METHRES = Y

Make Global setting METHRES = Y to force instantaneous current and voltage metered values to zero when the applied signal is less than the values shown in *Table 8.5*.

Table 8.5 Metering Thresholds (Secondary Units)

Channels:	Metering Threshold
IA, IB, IC	0.005 A
IN	0.001 A
VAY, VBY, VCY VAZ, VBZ, VCZ	0.1 V (300 V nominal inputs)

VOLTAGE METERING THRESHOLDS
Calculate the metering threshold for 8 Vac LEA voltage inputs by using the threshold value 0.1 V as shown in Table 8.5:
$0.0027 \text{ V} = 0.1 \text{ V} \cdot (8/300)$

Threshold values for other LEA voltage inputs are calculated similarly. See Voltage-Related Settings and LEA Inputs (Group Settings) on page 9.47 for more information.

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The metered values are forced to zero on a phase-by-phase basis. For example, if IA is below the applicable threshold shown in *Table 8.5* but IB, IC, and IN are all above their respective thresholds, then the fundamental magnitude and angle for IA are forced to zero, but the metered values for IB, IC, and IN are unchanged.

When a fundamental value is forced to zero, other metering displays are also impacted. In the above example, the A-phase current inputs to metered sequence values, power calculations, demand calculations, and energy calculations are also forced to zero. The changes impact all nonharmonic meter reports available from any interface on the relay including ASCII reports, the webpages, Fast Meter reports, etc. The changes do not affect harmonics metering, protection, synchrophasors, or event reporting.

METHRES = N

Make Global setting METHRES = N to disable all meter threshold checks. When METHRES = N, some energy may be accumulated and some small value is input to the demand models even if the breaker is open.

METHRES = E

Make Global setting METHRES = E to force the inputs to the energy and power demand calculations to zero when currents drop below the thresholds shown in *Table 8.5* and when Relay Word bits 52AA, 52AB, 52AC, or 52A3P = 0. If 52AA, 52AB, 52AC, or 52A3P = 1 or current is above the levels shown in *Table 8.5*, then energy and power demand metering continue unaffected by any threshold check (see *Figure 8.6*). METHRES = E only impacts power demand and energy metering. Fundamental metering and current demand metering are not affected. Metered voltages are never forced to zero when METHRES = E.
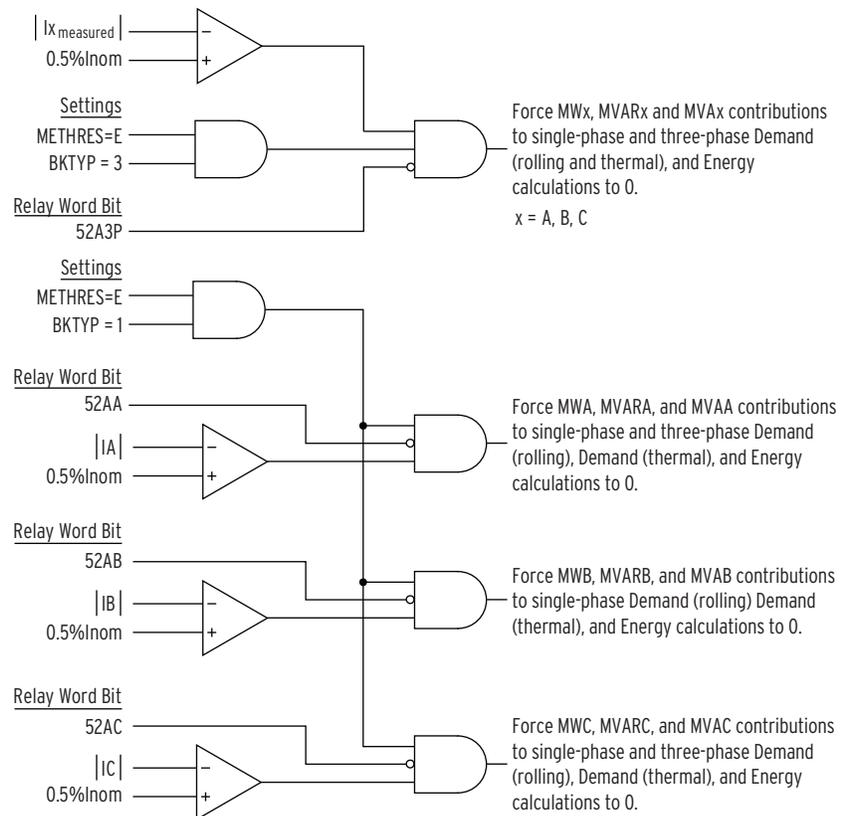
Figure 8.6   Metering Threshold Logic for Energy and Demand Metering

Harmonics and True RMS Metering

The SEL-651R-2 is capable of measuring signal distortions as high as the 16th harmonic on the ten analog input channels.

The signals connected to the SEL-651R-2 terminals I1, I2, I3, IN, V1Y, V2Y, V3Y, V1Z, V2Z, and V3Z are first conditioned by analog low-pass filters, and then sampled at 32 times per power system cycle and placed into internal quantities with the following names:

➤ IA, IB, IC, IN

➤ VAY, VBY, VCY

➤ VAZ, VBZ, VCZ

according to the Global settings IPCONN, VYCONN, and VZCONN. See *Current and Voltage Connections (Global Settings) on page 9.28* for more details.

Every two seconds, a 1024-sample data set from each channel is processed to calculate:

➤ Fundamental root-mean-square (rms) magnitude (1st harmonic, in primary units)

➤ Harmonic content *n*, where *n* = 2–16 (in percent of fundamental)

➤ Total Harmonic Distortion (THD)

➤ True rms magnitude (in primary units)

Additionally, if Global setting VSELECT ≠ OFF:

➤ Average real power (in primary MW) is calculated.

Harmonic Metering

The harmonic calculations are visible in the serial port **MET H** command and through the front-panel METER menu. See *Section 10: Communications* for a sample **MET H** command response and *Section 11: Front-Panel Operations*. This command includes the fundamental rms, true rms, and THD values for each quantity, along with the individual harmonics.

The fundamental rms magnitude value is expressed in A primary for the current channels (IA, IB, IC, and IN) and kV primary for the voltage channels.

The individual harmonics (2nd–16th) are expressed as a percentage of the fundamental, with an upper limit of 500 percent.

There is no dc component calculated.

To avoid calculating meaningless harmonics during outages, if the fundamental magnitude of a channel is less than shown in *Table 8.6*, the harmonics and the THD calculations are set to zero for that channel.

Table 8.6   Harmonic and THD Calculation Thresholds (Sheet 1 of 2)

Channel	Threshold
IA, IB, IC	Setting CTR • 1 A • 0.02
IN	Setting CTRN • 0.2 A • 0.02

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Synchrophasor Metering

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Table 8.6 Harmonic and THD Calculation Thresholds (Sheet 2 of 2)

Channel	Threshold
VAY, VBY, VCY	Setting PTRY • 300 V • 0.02
VAZ, VBZ, VCZ	Setting PTRZ • 300 V • 0.02

The THD quantities are available for control functions by using them in SELOGIC control equations as part of an analog comparison. See *Table 7.2* for details. The THD quantities are calculated using the formula:

$$\mathrm{THD}_q = \left(\sqrt{\left(\frac{\mathrm{True\ RMS}_q}{\mathrm{Fundamental\ RMS}_q} \right)^2 - 1} \right) \bullet 100$$

where *q* is the current or voltage quantity for which the THD is to be determined.

True RMS Metering

The true rms calculations are visible in the serial port **MET RMS** command and through the front-panel METER menu. The true rms value is expressed in A primary for the current channels (IA, IB, IC, and IN) and kV primary for the voltage channels. See *Section 10: Communications* for a sample **MET RMS** command response and *Section 11: Front-Panel Operations*.

The rms meter calculations include the average per-phase and three-phase real power in primary MW based on currents IA, IB, and IC, and voltages VAY, VBY, and VCY if Global setting VSELECT := VY; and voltages VAZ, VBZ, and VCZ if Global setting VSELECT := VZ. The phantom voltage setting, EPHANT, has no effect on the average power calculations.

The true rms calculations are based on the same 1024-sample data set that is used in the harmonics calculations. The true rms values are scalar quantities, therefore no phase angle or polarity sign is included.

The true rms current and voltage readings will differ from the fundamental rms magnitude calculated in the harmonics metering function if there is any harmonic energy content in the signal.

NOTE: When testing the SEL-651R-2, remember that the SEL-651R-2 protection functions (overcurrent elements, undervoltage elements, etc.) are based on fundamental rms values, not true rms values.

Similarly, the average power quantities will differ from the fundamental power quantities when there is harmonic energy in voltage or current signals. The average power quantities are directional, so they are affected by the Global CT Polarity setting CTPOL (see *Table 8.1*).

Synchrophasor Metering

View Synchrophasor Metering Information Via Serial Port

The **MET PM** command (see *MET PM (Synchrophasor Metering) on page 10.62*) displays the synchrophasor measurements. For more information, refer to *View Synchrophasors by Using the MET PM Command on page J.17*.

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High-Impedance Fault Metering
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High-Impedance Fault Metering

View HIF Metering Information Via Command Line (Only Available in Relays That Support Arc Sense Technology)

The relay provides high-impedance fault detection data through the **MET HIF** command. The **MET HIF** command displays the instantaneous high-impedance alarm and fault detection values for each phase (ALG2. A, ALG2. B, and ALG2. C) as a percentage of their final pickup value. When an instantaneous value reaches 100 percent, the associated alarm/fault Relay Word bit (HIA2_A, HIA2_B, HIA2_C, HIF2_A, HIF2_B, or HIF2_C) asserts. The **MET HIF** command is available at Access Level 1 or higher. The command supports an optional number parameter 1–32767 that repeats the command the specified number of times.

If high-impedance fault detection is not enabled (EHIF = N), the response to the **MET HIF** command is "HIF Not Enabled". If high-impedance fault detection is enabled (EHIF = Y) and any of the initial tuning Relay Word bits, ITUNE_A, ITUNE_B, or ITUNE_C, are asserted, the response is "HIF Algorithm Tuning in Progress". The initial tuning period is 24 hours. (See *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111* for details on high-impedance fault detection.)

Issuing the **MET HIF** command will display the following information, when the command is available:

```
=>>MET HIF <Enter>

FEEDER 1                        Date: 07/31/2012  Time: 16:21:25.256
STATION A                       Time Source: internal

           ALG.2 A    ALG.2 B    ALG.2 C
Alarm (%)   18.59      34.78      12.56
Fault (%)   14.89      15.46       7.55
```

Breaker/Recloser Contact Wear Monitor

The breaker/recloser contact wear monitor in the SEL-651R-2 provides information that helps in scheduling circuit breaker or recloser maintenance. This monitoring function accumulates the number of internal and external trip operations and integrates the number of close-open operations and the per-phase current during each opening operation. The SEL-651R-2 compares the integrated close-open information to a predefined breaker or recloser maintenance curve to calculate the percent contact wear on a per-phase basis. The SEL-651R-2 updates and stores the contact wear information and the number of trip operations in nonvolatile memory. You can view this information through the front-panel display and by communicating with the SEL-651R-2 through any serial communications port with a computer.

Individual phase Breaker Contact Wear bits, BCWA, BCWB, and BCWC, assert when the contact wear percentage on their respective phases reaches 100 percent. You can use these individual phase elements or the combined result of these elements, BCW (which asserts when BCWA or BCWB or BCWC assert), in a SELOGIC control equation to alarm or control other functions, such as block reclosing.

Involved phase and ground/earth fault information is also tabulated for each breaker or recloser operation.

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Breaker/Recloser Contact Wear Monitor

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This feature will be called "breaker monitor" for the remainder of this section and elsewhere in this instruction manual, except where a distinction must be made between breakers and reclosers.

The breaker monitor is enabled with the Global setting:

EBMON := **Y**

The breaker monitor settings in *Table 8.7* are available via the **SET G** command (see *Table 9.1*, the settings sheets at the end of *Section 9*, and *BRE Command (Breaker Monitor Data) on page 10.40*).

When setting EBMON := N, the breaker monitor is disabled from accumulating any new data. Any data previously recorded are unaffected and can still be accessed.

The breaker monitor is set with breaker or recloser maintenance information provided by the switchgear manufacturer. This breaker maintenance information lists the number of close/open operations that are permitted for a given current interruption level.

MULTI-RECLOSER INTERFACE
The BKMONx setting values in Table 9.15 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93.

Table 8.7   Breaker Monitor Settings and Settings Ranges

Setting	Definition	Range
COSP1	Close/Open set point 1—maximum	0–65000 close/open operations
COSP2	Close/Open set point 2—middle	0–65000 close/open operations
COSP3	Close/Open set point 3—minimum	0–65000 close/open operations
KASP1	kA Interrupted set point 1—minimum	0.00–999.00 kA in 0.01 kA steps
KASP2	kA Interrupted set point 2—middle	0.00–999.00 kA in 0.01 kA steps
KASP3	kA Interrupted set point 3—maximum	0.00–999.00 kA in 0.01 kA steps
BKMON3P BKMONA BKMONB BKMONC	SELOGIC control equation breaker monitor initiation settings	Relay Word bits referenced in *Appendix F: Relay Word Bits*

Setting notes:

➤ COSP1 must be set greater than COSP2.

➤ COSP2 must be set greater than or equal to COSP3.

➤ KASP1 must be set less than KASP2.

➤ If COSP2 is set the same as COSP3, then KASP2 must be set the same as KASP3.

➤ KASP3 must be set at least 5 times (but no more than 100 times) the KASP1 setting value.

➤ KASP2 must be set less than or equal to KASP3.

Table 8.8 lists the breaker monitor setting values for several common three-phase recloser types. Make the six settings (COSP1, COSP2, COSP3, KASP1, KASP2, and KASP3) in the Global settings after setting EBMON := Y.

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Table 8.8   Recommended Breaker Monitor Settings for Various Reclosers

Recloser Model	Recloser Type	Interrupt Rating (A primary)	Settings			
			COSP1	COSP2 COSP3	KASP1	KASP2 KASP3
RXE	OIL	6000	10000	20	0.10	6.00
RVE	OIL	6000	10000	20	0.10	6.00
WE	OIL	12000 (@ 4.8 kV)	10000	20	0.19	12.00
WE	OIL	10000 (@ 14.4 kV)	10000	20	0.16	10.00
VWE	VACUUM	12000	10000	80	0.48	12.00
VWVE27	VACUUM	12000	10000	80	0.48	12.00
VWVE38X	VACUUM	12000	10000	80	0.48	12.00
WVE27	OIL	8000	10000	20	0.13	8.00
WVE38X	OIL	8000	10000	20	0.13	8.00
VSA12	VACUUM	12000	10000	80	0.48	12.00
VSA16	VACUUM	16000	10000	80	0.64	16.00
VSA20	VACUUM	20000	10000	80	0.80	20.00
VSA20A	VACUUM	20000	10000	80	0.80	20.00
VSA20B	VACUUM	20000	10000	80	0.80	20.00
VSO12	VACUUM	12000	10000	80	0.48	12.00
VSO16	VACUUM	16000	10000	80	0.64	16.00
G&W Viper-S or Viper-ST 15.5 or 27 kV	VACUUM	12500	10000	2510 64	1.25	2.00 12.50
G&W Viper-S or Viper-ST 38 kV	VACUUM	12000	10000	100	1.25	12.00

The parameters in *Table 8.8* are derived from ANSI C37.61-1973/IEEE Standard 321-1973, IEEE Standard Guide for the Application, Operation, and Maintenance of Automatic Circuit Reclosers.

For example, if the SEL-651R-2 is connected to a type WVE27 Recloser, use the **SET G** command to enter and save the following Global settings for the breaker wear monitor:

EBMON := **Y**

COSP1 := **10000**

COSP2 := **20**

COSP3 := **20**

KASP1 := **0.10**

KASP2 := **8.00**

KASP3 := **8.00**

MULTI-RECLOSER INTERFACE
The BKMONx setting values in Table 9.15 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93. Also, Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface.

If single-phase reclosers or breakers are connected to the SEL-651R-2, make Global setting BKTYP := 1. The same breaker monitor settings (COSP1, COSP2, COSP3, KASP1, KASP2, and KASP3) are used for all three phases.

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The remaining breaker monitor settings are the SELOGIC control equations that control when the breaker monitor function accumulates data. These settings are BKMON3P for three-phase breakers, and BKMONA, BKMONB, and BKMONC for single-phase breakers (see *Operation of SELOGIC Control Equation Breaker Monitor Initiation Settings on page 8.29*).

Breaker Monitor Setting Example

If your recloser is not included in *Table 8.8*, or you adapt the SEL-651R-2 to operate a breaker, you can create a contact wear monitor curve for your specific breaker or recloser. The breaker/recloser contact wear monitor is set with breaker or recloser maintenance information provided by the switchgear manufacturer. This maintenance information lists the number of close/open operations that are permitted for a given current interruption level. The following is an example of breaker maintenance information for a 25 kV circuit breaker.

Table 8.9   Breaker Maintenance Information for a 25 kV Circuit

Current Interruption Level (kA)	Permissible Number of Close/Open Operations[a]
0.00–1.20	10,000
2.00	3,700
3.00	1,500
5.00	400
8.00	150
10.00	85
20.00	12

[a] The action of a circuit breaker closing and then later opening is counted as <u>one</u> close/open operation.

The breaker maintenance information in *Table 8.9* is plotted in *Figure 8.7*.

Connect the plotted points in *Figure 8.7* for a breaker maintenance curve. To estimate this breaker maintenance curve in the SEL-651R-2 breaker monitor, enter three set points:

Set Point 1—*maximum* number of close/open operations with corresponding current interruption level.

Set Point 2— number of close/open operations that correspond to some *midpoint* current interruption level.

Set Point 3— number of close/open operations that correspond to the *maximum* current interruption level.

Enter these three points with the settings in *Table 8.7*.

The following settings are made from the breaker maintenance information in *Table 8.9* and *Figure 8.7*:

COSP1 := **10000**

COSP2 := **150**

COSP3 := **12**

KASP1 := **1.20**

KASP2 := **8.00**

KASP3 := **20.00**

Figure 8.8 shows the resultant breaker maintenance curve.

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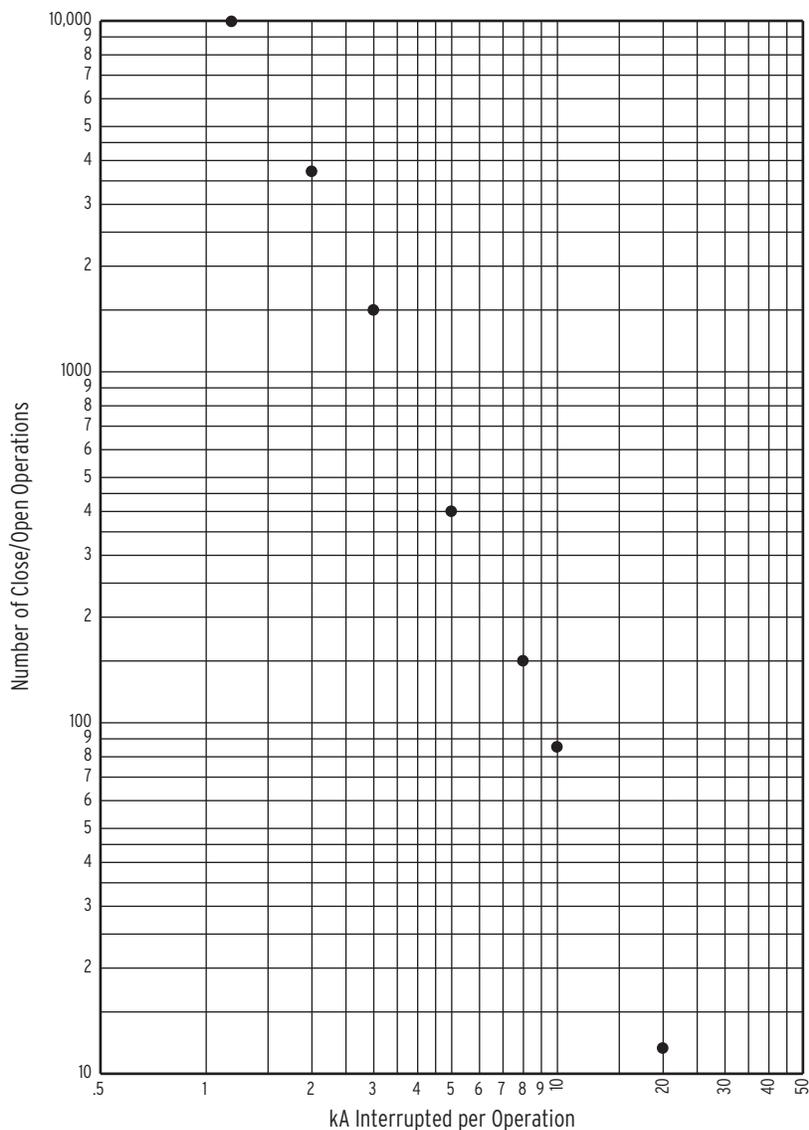
Figure 8.7   Plotted Breaker Maintenance Points for a 25 kV Circuit Breaker

Breaker Maintenance Curve Details

In *Figure 8.8*, note that set points KASP1, COSP1 and KASP3, COSP3 are set with breaker maintenance information from the two extremes in *Table 8.9* and *Figure 8.7*.

In this example, set point KASP2, COSP2 happens to be from an in-between breaker maintenance point in the breaker maintenance information in *Table 8.9* and *Figure 8.7*, but it does not have to be. Set point KASP2, COSP2 should be set to provide the best curve-fit with the plotted breaker maintenance points in *Figure 8.7*.

Regardless of the type of circuit breaker or recloser connected to the SEL-651R-2 (single-phase or three-phase), each phase (A, B, and C) has its own breaker maintenance curve (like that in *Figure 8.8*) because the separate circuit breaker interrupting contacts for phases A, B, and C do not necessarily interrupt the same magnitude current, depending on fault type and loading.

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Also, in the case of single-phase breakers or reclosers, one or two phases may not even operate for certain faults, and the contacts and mechanisms are not subjected to any wear.
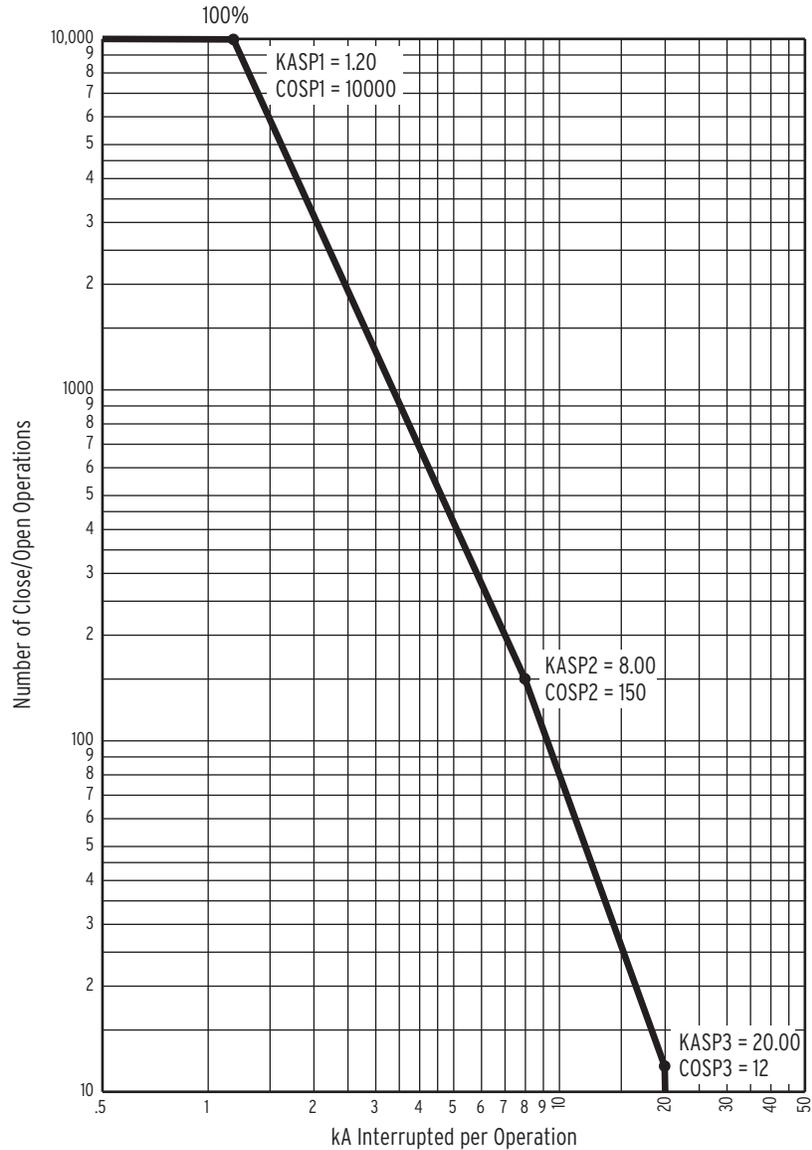
Figure 8.8   SEL-651R-2 Breaker Maintenance Curve for a 25 kV Circuit Breaker

In *Figure 8.8*, note that the breaker maintenance curve levels off horizontally below set point KASP1, COSP1. This is the close/open operation limit of the circuit breaker (COSP1 = 10000), regardless of interrupted current value.

Also, note that the breaker maintenance curve falls vertically above set point KASP3, COSP3. This is the maximum interrupted current limit of the circuit breaker (KASP3 = 20.00 kA). If the interrupted current is greater than setting KASP3, the interrupted current is accumulated as a current value equal to setting KASP3.

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Operation of SELOGIC Control Equation Breaker Monitor Initiation Settings

The SELOGIC control equation breaker monitor initiation settings BKMON3P, BKMONA, BKMONB, and BKMONC in *Table 8.7* determine when the breaker monitor reads in current values (Phases A, B, and C) for the breaker maintenance curve (see *Figure 8.8*) and the breaker monitor accumulated currents/trips and involved phase/ground counters (see *BRE Command (Breaker Monitor Data) on page 10.40*).

As previously described, separate breaker wear models are maintained for each of the three power system phases. These models are independently triggered when single-phase breakers are connected, and are triggered together when three-phase breakers are connected.

When a **three-phase recloser or breaker is connected**, Global setting BKTYP must be set to 3 (see *Section 9: Settings*). When BKTYP :=3, Global setting BKMON3P is the only breaker monitor initiation setting that can be made. BKMON3P controls the breaker monitor logic for all three phases.

When **single-phase capable reclosers or breakers are connected**, Global setting BKTYP must be set to 1. When BKTYP :=1, global breaker monitor initiation settings BKMONA, BKMONB, and BKMONC can be accessed. These settings control the breaker monitor logic for each phase separately. These three settings are present even if single-phase tripping is not employed. In this case, they should be set to operate together, as shown in a later subsection. Setting BKMON3P is not available when BKTYP := 1.

Regardless of which type of breaker is in use, the three breaker monitor models act similarly, and will be described once using "BKMON*p*" in place of BKMON3P, BKMONA, BKMONB, and BKMONC to avoid repeating the same information (*p* = 3P, A, B, or C).

The BKMON*p* setting looks for a rising edge (logical 0 to logical 1 transition) as the indication to read in current values. The acquired current values are then applied to the breaker maintenance curve and the breaker monitor accumulated currents/trips.

In the factory-default settings, the SELOGIC control equation breaker monitor initiation setting is set:

BKMONA := **RCTR1X**   (RCTR1X is the logic output of *Figure 7.26*)

BKMONB := **RCTR2X**   (RCTR2X is the logic output of *Figure 7.26*)

BKMONC := **RCTR3X**   (RCTR3X is the logic output of *Figure 7.26*)

These settings must be modified in certain installations. The recommended settings for BKMON*p* are covered in *Breaker Monitor Initiate Settings (Global Settings) on page 9.38*.

When BKMON*p* asserts (Relay Word bit RCTR_X goes from logical 0 to logical 1), the breaker monitor reads in the current values and applies them to the breaker monitor maintenance curve and the breaker monitor accumulated currents/trips (refer to *Figure 8.9*).

As detailed in *Figure 8.9*, the breaker monitor actually reads in the current values one cycle after the assertion of BKMON*p*. This helps especially if an instantaneous trip occurs. The instantaneous element trips when the fault current reaches its pickup setting level. The fault current may still be climbing to its full value, at which it levels off. The one-cycle delay on reading in the current values allows time for the fault current to level off.

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Figure 8.9   Operation of SELOGIC Control Equation Breaker Monitor Initiation Setting

See *Figure 8.14* and accompanying text for more information on setting BKMON*p*. The operation of the breaker monitor maintenance curve, when new current values are read in, is explained in the following example.

Breaker Monitor Operation Example

As stated earlier, each phase (A, B, and C) has its own breaker maintenance curve. For this example, presume that the interrupted current values occur on a single phase in *Figure 8.10–Figure 8.13*. Also, presume that the circuit breaker interrupting contacts have no wear at first (brand new or recent maintenance performed).

Note that in *Figure 8.10–Figure 8.13* the interrupted current in a given figure is the same magnitude for all the interruptions. For example, in *Figure 8.11*, 2.5 kA is interrupted 290 times. This is not realistic, but helps in demonstrating the operation of the breaker maintenance curve and how it integrates for varying current levels.

0–10 Percent Breaker Wear

Refer to *Figure 8.10*. Current value 7.0 kA is interrupted 20 times (20 close/open operations = 20 – 0), pushing the breaker maintenance curve from the 0 percent wear level to the 10 percent wear level.

Compare the 100 percent and 10 percent curves and note that for a given current value, the 10 percent curve has only 1/10 of the close/open operations of the 100 percent curve.

10–25 Percent Breaker Wear

Refer to *Figure 8.11*. The current value changes from 7.0 kA to 2.5 kA, and 2.5 kA is interrupted 290 times (290 close/open operations = 480 –190), pushing the breaker maintenance curve from the 10 percent wear level to the 25 percent wear level.

Compare the 100 percent and 25 percent curves and note that for a given current value, the 25 percent curve has only 1/4 of the close/open operations of the 100 percent curve.

25–50 Percent Breaker Wear

Refer to *Figure 8.12*. The current value changes from 2.5 kA to 12.0 kA, and 12.0 kA is interrupted 11 times (11 close/open operations = 24 – 13), pushing the breaker maintenance curve from the 25 percent wear level to the 50 percent wear level.

Compare the 100 percent and 50 percent curves and note that for a given current value, the 50 percent curve has only 1/2 of the close/open operations of the 100 percent curve.

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50–100 Percent Breaker Wear

Refer to *Figure 8.13*. The current value changes from 12.0 kA to 1.5 kA, and 1.5 kA is interrupted 3000 times (3000 close/open operations = 6000 – 3000), pushing the breaker maintenance curve from the 50 percent wear level to the 100 percent wear level.

When the breaker maintenance curve reaches 100 percent for a particular phase, the percentage wear remains at 100 percent (even if additional current is interrupted), until reset by the **BRE R** command (see *View or Reset Breaker Monitor Information on page 8.36*). But the current and trip counts continue to be accumulated, until reset by the **BRE R** command.

Additionally, logic outputs assert for alarm or other control applications; see the following discussion.

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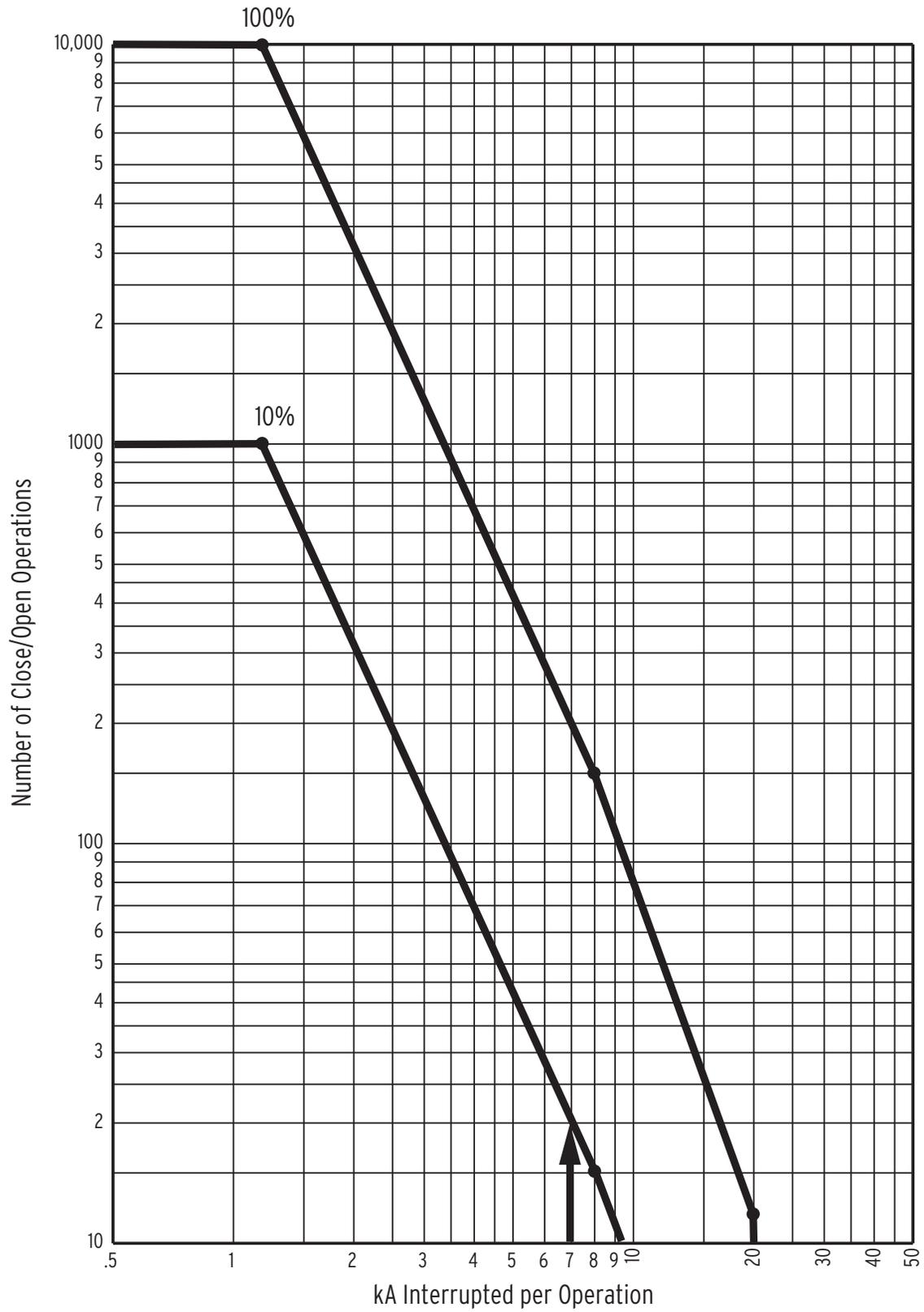
Figure 8.10   Breaker Monitor Accumulates 10 Percent Wear

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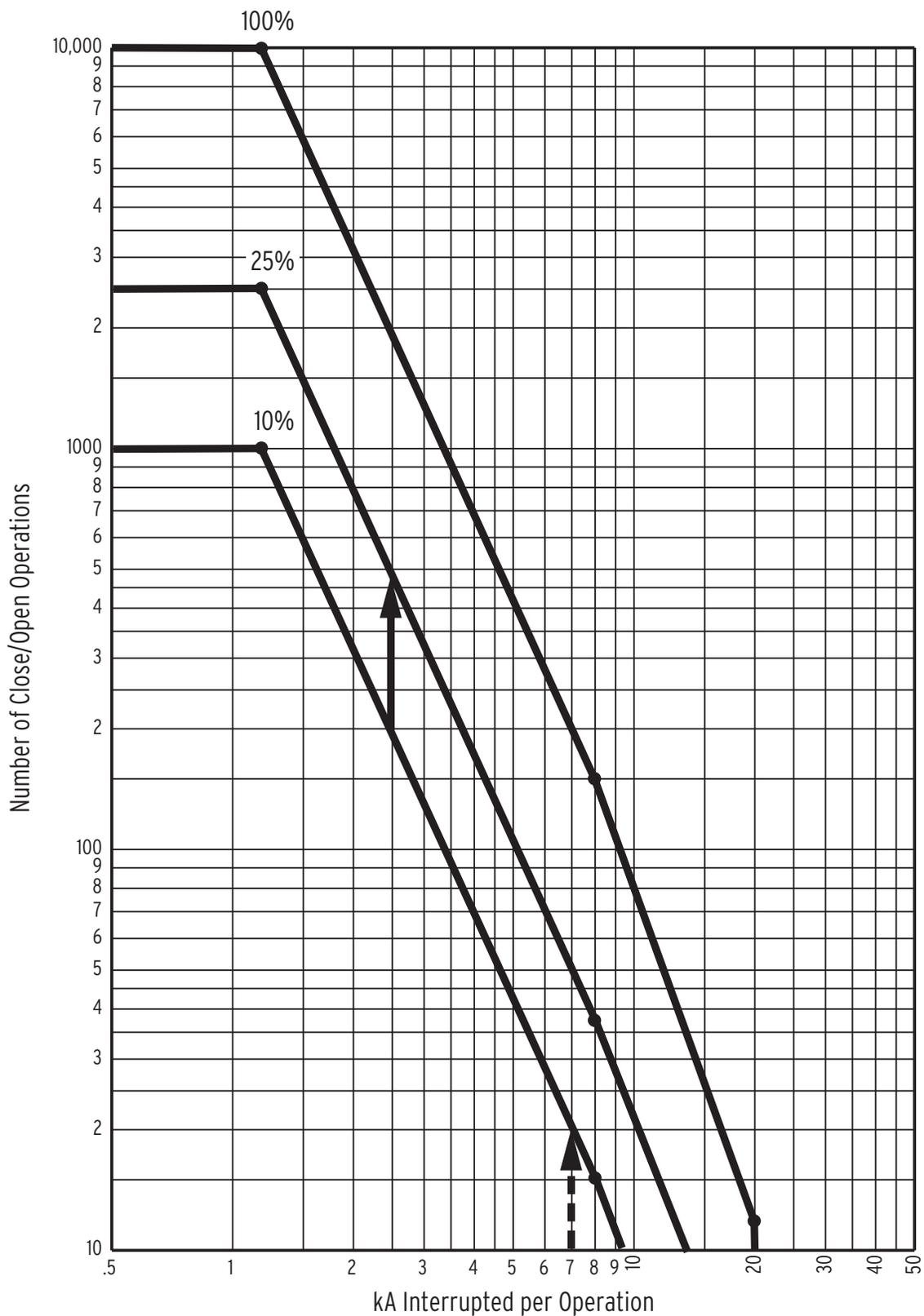
Figure 8.11   Breaker Monitor Accumulates 25 Percent Wear

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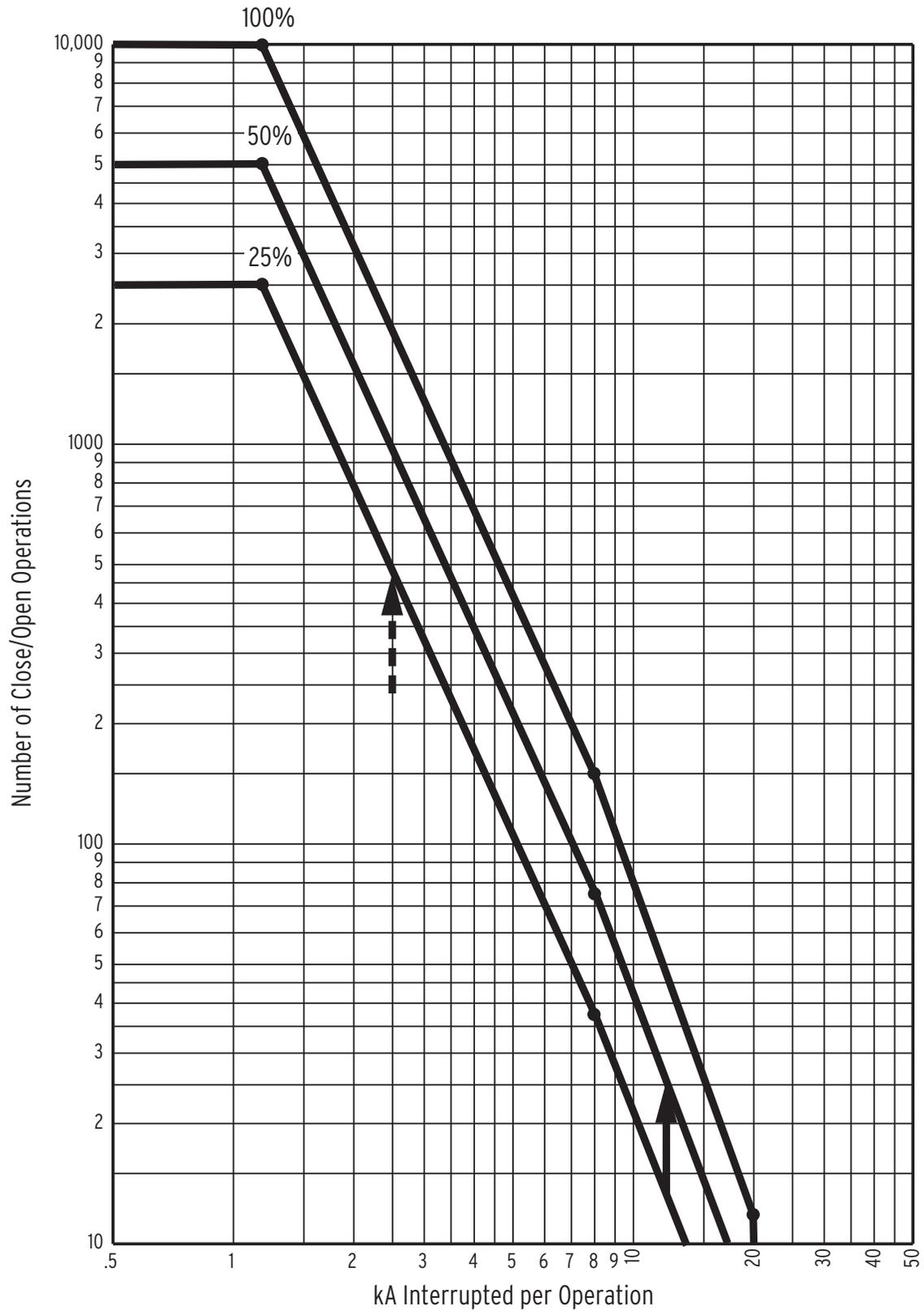
Figure 8.12   Breaker Monitor Accumulates 5O Percent Wear

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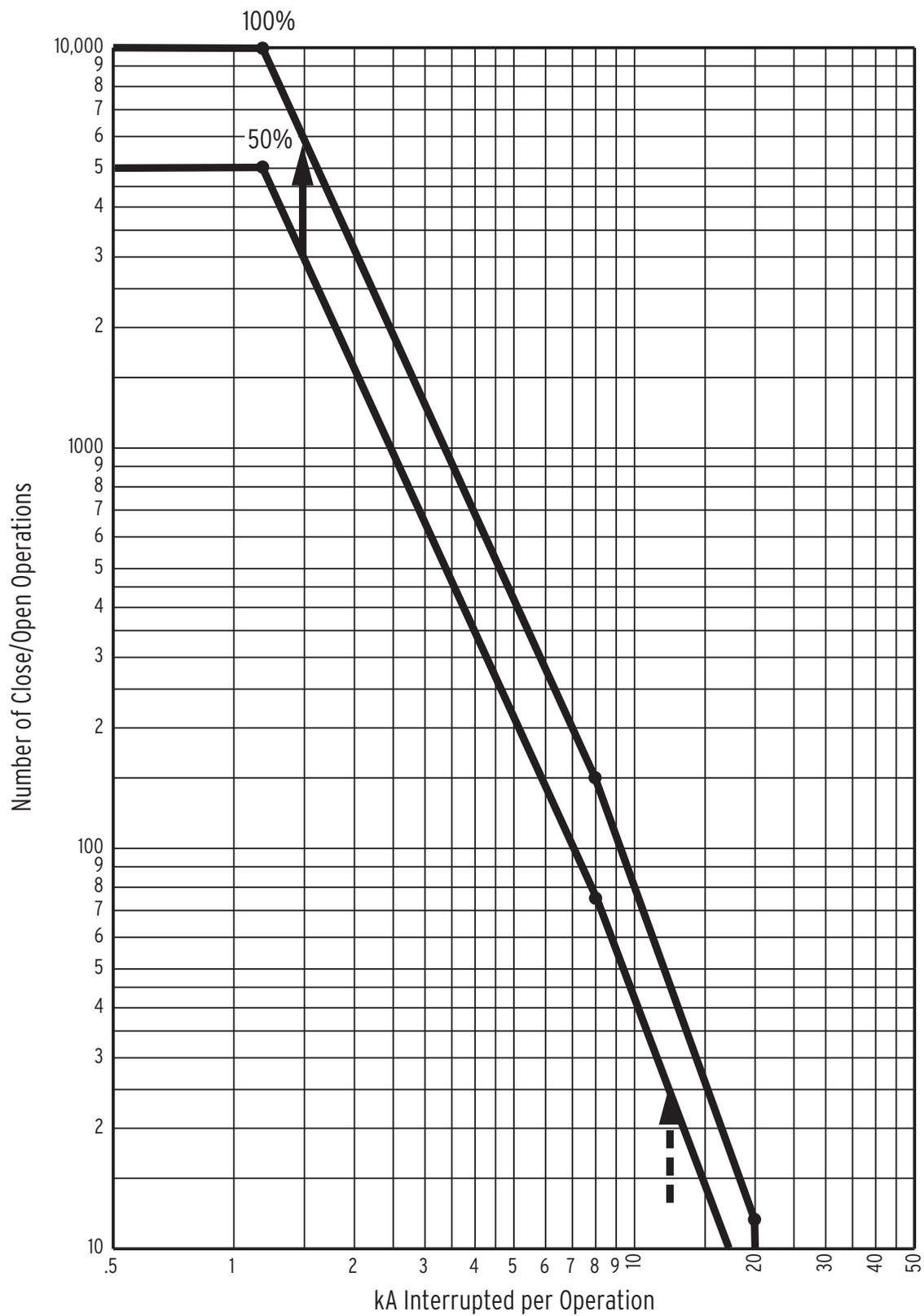
Figure 8.13   Breaker Monitor Accumulates 1OO Percent Wear

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Breaker Monitor Output

When the breaker maintenance curve for a particular phase (A, B, or C) reaches the 100 percent wear level (see *Figure 8.13*), a corresponding Relay Word bit (BCWA, BCWB, or BCWC) asserts.

Relay Word Bits	Definition
BCWA	Phase A breaker contact wear has reached the 100 percent wear level
BCWB	Phase B breaker contact wear has reached the 100 percent wear level
BCWC	Phase C breaker contact wear has reached the 100 percent wear level
BCW	BCWA OR BCWB OR BCWC

Example Applications

These logic outputs can be used to alarm:

OUT105 := **BCW**.

or to drive the recloser control to lockout the next time the recloser control trips:

79DTL3X := **TRIP3P AND BCW**. three-phase application

View or Reset Breaker Monitor Information

Accumulated breaker wear/operations data are retained if the recloser control loses power or the breaker monitor is disabled (setting EBMON := N). The accumulated data can only be reset if the **BRE R** command is executed; see the following discussion on the **BRE R** command.

Via Serial Port

The **BRE** command displays the following information (see *BRE Command (Breaker Monitor Data) on page 10.40*):

➤ Accumulated number of internal (recloser control) initiated trips

➤ Accumulated interrupted current from internal (recloser control) initiated trips

➤ Accumulated number of externally initiated trips

➤ Accumulated interrupted current from externally initiated trips

➤ Percent circuit breaker contact wear for each phase

➤ Accumulated number of trips involving A-phase, B-phase, and C-phase

➤ Accumulated number of trips involving ground (G)

➤ Date when the preceding items were last reset (via the **BRE R** command)

The **BRE W** command allows the trip counters, accumulated values, percent breaker wear, and involved phase/ground counters to be preloaded for each individual phase (see *BRE Command (Breaker Monitor Data) on page 10.40*).

The **BRE R** command resets the accumulated values and the percent wear for all three phases. For example, if breaker contact wear has reached the 100 percent wear level for A-phase, the corresponding Relay Word bit BCWA

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asserts (BCWA = logical 1). Execution of the **BRE R** command resets the wear levels for all three phases back to 0 percent and consequently causes Relay Word bit BCWA to deassert (BCWA = logical 0).

Via Front Panel

The information and reset functions available via the previously discussed serial port commands **BRE** and **BRE R** are also available via the front-panel menu entry Monitor (see *SEL-651R-2 Menu on page 11.5*).

Determination of Internally Initiated Trips and Externally Initiated Trips

Note in the **BRE** command response that the accumulated number of trips and accumulated interrupted current are separated into two groups of data: those generated by *internally initiated trips* (Internal Trips) and those generated by *externally initiated trips* (External Trips). The categorization of these data is determined by the status of the TRIPp Relay Word bit when the SEL$_{OGIC}$ control equation breaker monitor initiation setting BKMONp operates (see *BRE Command (Breaker Monitor Data) on page 10.40*).

Refer to *Figure 8.9* and accompanying explanation. If BKMONp newly asserts (logical 0 to logical 1 transition), the recloser control reads in the current values (Phases A, B, and C). Now the decision has to be made: is this current and trip count information accumulated under *internally initiated trips* or *externally initiated trips*?

To make this determination, the status of the TRIPp Relay Word bit is checked at the instant BKMONp newly asserts (TRIPp is the logic output of *Figure 5.1*). If TRIPp is asserted (TRIPp = logical 1), the current and trip count information is accumulated under *internally initiated trips* (Int Trips). If TRIPp is deasserted (TRIPp = logical 0), the current and trip count information is accumulated under *externally initiated trips* (Ext Trips).

Regardless of whether the current and trip count information is accumulated under internally initiated trips or externally initiated trips, this same information is routed to the breaker maintenance curve for continued breaker wear integration (see *Figure 8.9–Figure 8.13*).

Internally initiated trips (Internal Trips) are also referred to as *Relay Initiated Trips* or *Control Initiated Trips*, and these terms are used interchangeably throughout this and other SEL instruction manuals.

Internal and External Trip Counters

When one of the BKMONp settings is newly asserted, the corresponding internal or external count is incremented using the method shown in the previous subsection to determine internal versus external trips.

To avoid multiple counting in single-phase trip applications, a new count is only recorded when a breaker is closed at the instant that the associated BKMONp setting asserts. For example, if the breaker on phase-B is already open and BKMONB asserts, the internal or external trip counter will not increment because the breaker was already open when BKMONB asserted. The Relay Word bits SPOA, SPOB, and SPOC are used to provide the breaker open status information.

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Involved Phase and Ground Counters

The involved phase and ground counters are incremented whenever a current exceeds one of the time-overcurrent element settings one cycle after BKMONp asserts:

The A-phase counter is incremented if |IA| is greater than: 51PJP, 51PKP, 51AJP, or 51AKP.

The B-phase counter is incremented if |IB| is greater than: 51PJP, 51PKP, 51BJP, or 51BKP.

The C-phase counter is incremented if |IC| is greater than: 51PJP, 51PKP, 51CJP, or 51CKP.

The ground counter is incremented if |IG| is greater than: 51G1JP, 51G1KP, 51G2JP, or 51G2KP, and Relay Word bit SPO (single pole open) was deasserted at the rising edge of BKMONp.

If no time-overcurrent element pickup settings are enabled, this feature will not operate. To ensure that it operates, time-overcurrent element pickup values must be set, even if they are not used for tripping.

In single-phase tripping applications, if more than one of the BKMONp settings asserts, the phase involvement counters are updated one cycle after the first BKMONp setting asserts.

Factory-Default Setting Example

As discussed previously, the SELOGIC control equation breaker monitor initiation factory-default setting is:

BKMON3P := **RCTR1X** when BKTYP := 3

BKMONA := **RCTR1X** when BKTYP := 1

BKMONB := **RCTR2X** when BKTYP := 1

BKMONC := **RCTR3X** when BKTYP := 1

MULTI-RECLOSER INTERFACE
The BKMONx setting values in Table 9.15 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93. Also, Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface.

Thus, any new assertion of BKMONp will be deemed an internal trip, and the current and trip count information is accumulated under *internally initiated trips*.

Additional Example

Output contact OUT101 is set to provide tripping (refer to *Figure 8.14*):

OUT101 := **TRIP3P**

Note that optoisolated input IN106 monitors the trip bus. If the trip bus is energized by output contact OUT101, an external control switch, or some other external trip, then IN106 is asserted.

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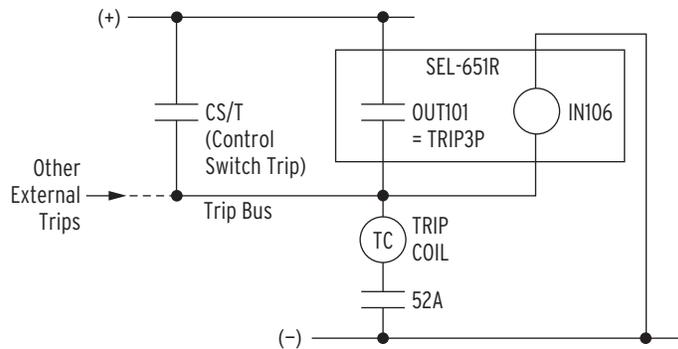
Figure 8.14   Input IN106 Connected to Trip Bus for Breaker Monitor Initiation

If the SELOGIC control equation breaker monitor initiation setting is set:

BKMON3P := **IN106**

then the SEL-651R-2 breaker monitor detects all trips.

If output contact OUT101 asserts, energizing the trip bus, the breaker monitor will deem it an *internally initiated trip*. This is because when BKMON3P is newly asserted (input IN106 energized), the TRIP3P Relay Word bit is asserted. Thus, the current and trip count information is accumulated under *internally initiated trips*.

If the control switch trip, or some other external trip, asserts, energizing the trip bus, the breaker monitor will deem it an *externally initiated trip*. This is because when BKMON3P is newly asserted (input IN106 energized), the TRIP3P Relay Word bit is deasserted. Thus, the current and trip count information is accumulated under *externally initiated trips*.

Battery System Monitor

NOTE: Units ordered with 125 Vdc or 48 Vdc power supplies do not contain a battery or the battery charging circuitry. These units will continuously assert the BTFAIL Relay Word bit, and some settings must be modified accordingly.

NOTE: If Global setting PWRDN_AC is changed while ac power is removed (SEL-651R-2 is operating off battery power), the new PWRDN_AC setting does not become active until the next loss of ac power. Likewise, if Global setting PWRDN_WU is changed while ac power is removed (SEL-651R-2 is operating off battery power), the new PWRDN_WU setting does not become active until the next press of the WAKE UP pushbutton.

The SEL-651R-2 monitors the internal battery system, which includes the battery charger and battery. This subsection describes how the battery system operates, how the battery system is automatically and manually checked, and what the SEL-651R-2 does when it detects a problem with the battery system.

The following settings are discussed in this subsection:

➤ Power-off Delay After AC Loss (OFF, 1–1440 min.)
PWRDN_AC := 180

➤ Power-off Delay After Wake Up (OFF, 1–1440 min.)
PWRDN_WU := 20

➤ Request Battery Test SELOGIC Control Equation
TESTBATT := NA

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These Global settings are available via the **SET G** command, described in *Section 10: Communications*. The example setting values listed above will be used in the description that follows.

Battery System Operation

The 12 V lead-acid battery powers the SEL-651R-2 and provides trip and close power to the capacitors when the ac source is de-energized. The SEL-651R-2 includes a temperature-compensated 12 V battery charger powered from an external ac source. See *Section 1: Introduction and Specifications* for battery specifications.

When the ac source is energized, the SEL-651R-2 built-in battery monitor/charger controls charging current to the battery system. When ac power is present, the SEL-651R-2 will charge the battery in one of three modes:

➤ Constant current charge

➤ Fast charge

➤ Float charge

The transition between the charge modes is determined by measured battery current, voltage, temperature, and time spent in each mode.

The CHRGG Relay Word bit asserts when the battery is charging (when the ac source is energized). The DISCHG Relay Word bit asserts when the battery is discharging (when the ac source is de-energized and the SEL-651R-2 is operating from battery power).

The SEL-651R-2 tests the battery by subjecting it to a load test for 10 seconds. Relay Word bit DISTST asserts during a load test. If the battery voltage falls too low during the test, the discharge test failure Relay Word bit DTFAIL asserts. DTFAIL remains asserted until the next successful battery load test.

If the battery fails, or when you remove them temporarily during replacement, the ac source provides sufficient energy to trip and close most reclosers. However, the ac source voltage may dip significantly during a fault, reducing or eliminating the source voltage needed to power the SEL-651R-2 and trip the recloser. To counteract this, the SEL-651R-2 can ride through 0.5 seconds of ac source (and battery) loss. During this 0.5 seconds ride-through time, the SEL-651R-2 can still issue a trip—such a trip would likely be a high-current instantaneous or fast curve operation.

SEL-651R-2 Puts Itself to Sleep

If the ac source is de-energized, the SEL-651R-2 operates off battery power and initiates a countdown timer that starts with the Global setting value PWRDN_AC, in minutes. If the ac source does not re-energize before the countdown timer reaches zero, the SEL-651R-2 will shut itself off. The final action before the control shuts down is to make a Going to Sleep entry in the Sequential Events Records (SER) report. The example setting value of PWRDN_AC := 180 minutes provides a three-hour standby time before the unit shuts off.

The 12-volt dc auxiliary power source is also shut off whenever the SEL-651R-2 is off. See *+12 Vdc Auxiliary Power Supply on page 2.52* for details on the 12 Vdc power supply output.

This sleep feature allows the battery to be left in a partially charged state, rather than completely discharged, and allows power to be available for subsequent front-panel operator activities (see *Wake Up the SEL-651R-2*).

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When the countdown reaches one minute, the TOSLP (to sleep) Relay Word bit asserts and stays asserted, to allow some final control action to be taken before protection is disabled (see *Possible Application of TOSLP Relay Word Bit on page 8.41*).

During the ac outage, if the countdown timer has not reached 0 and the battery voltage drops too low, the control will be disabled and will shut off immediately to protect the battery. In this case, the TOSLP bit will not be asserted.

If ac power comes back after the TOSLP bit has asserted, but before the SEL-651R-2 shuts down, the TOSLP bit will be deasserted and the control will abort the countdown. If ac power fails again, the countdown timer will load with the PWRDN_AC setting and start over again.

Wake Up the SEL-651R-2

When the SEL-651R-2 is in the sleep mode, it wakes up when either of the following occurs:

➤ The ac source is re-energized

➤ The front-panel **WAKE UP** pushbutton is operated

After the SEL-651R-2 is awakened via the front-panel **WAKE UP** pushbutton, the SEL-651R-2 initiates a countdown timer that starts with the Global setting value PWRDN_WU, in minutes. If the ac source does not re-energize before the countdown timer reaches zero, the SEL-651R-2 will turn itself off.

The SEL-651R-2 will continue to operate on battery power until the countdown reaches zero. See the previous subsection for a description of the TOSLP Relay Word bit, which operates identically for the countdown timing after a wake-up operation. The example setting value of PWRDN_WU := 20 minutes provides a 20 minute standby time before the unit shuts off, unless the front panel is being used.

While ac is off, if a front-panel pushbutton is pressed and the present countdown is less than 15 minutes, the countdown timer is loaded with 15 minutes. This ensures that the control stays energized as long as an operator is using the front panel. If an operator is using a laptop computer to access data during an ac outage, a front-panel button (e.g., **ESC**) should be pressed periodically to ensure that the unit does not shut off before the data retrieval is completed.

If the SEL-651R-2 wakes up because the ac power source was energized and then de-energized before the SEL-651R-2 control completes the initialization routine, upon detecting that ac power is not present, it will function as if the **WAKE UP** pushbutton was pressed, described above.

If there is insufficient battery voltage when the **WAKE UP** pushbutton is pressed, the SEL-651R-2 will not wake up.

Possible Application of TOSLP Relay Word Bit

If allowed by system operating procedures, a possible application of the TOSLP Relay Word bit is to use it in a trip equation to open the recloser or circuit breaker. This action can improve the coordination on radial systems after the system is re-energized, because the line section beyond the SEL-651R-2 would be isolated while the recloser control is starting up.

Before tripping the breaker or recloser, a nonvolatile latch could be set to indicate that the recloser control performed the trip based on a loss of source power. When the power comes back on and the SEL-651R-2 initializes, it

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could reclose the breaker/recloser when it determines that the nonvolatile latch is in the asserted position. This function could be supervised by any Hot Line Tag or Reclose Block conditions.

Without this approach, the breaker or recloser is left in the closed position when the recloser control shuts down. The recloser control is then unable to protect the line for a few seconds after power is restored, while it performs the diagnostic checks that are part of its start-up sequence, which could lead to coordination difficulties if there is a fault on the load side of the recloser.

Battery System Diagnostics

The SEL-651R-2 monitors the 12 V battery system, including charge/discharge current, battery voltage, and temperature. The SEL-651R-2 automatically applies a battery load test approximately once per day and includes provisions to perform a battery load test via the serial communications ports or SELOGIC. You can obtain vital battery system information from the SEL-651R-2 status report via the front-panel and serial communications ports.

Automatic Battery Load Test

ISSUE STA C COMMAND AFTER REPLACING BATTERY
If the battery is replaced after a battery test failure, issue the **STA C** command to clear the battery test failure status.

The SEL-651R-2 automatically load tests the 12 V battery about every 24 hours. An internal 24-hour timer cumulatively times whenever the SEL-651R-2 is in the float-charge mode, such as when ac voltage is powering the SEL-651R-2 and charging the battery. Even if the battery is fully charged, the SEL-651R-2 maintains a low-rate charging current, so it is still in the float-charge mode.

If the 24-hour timer runs out and the SEL-651R-2 is still in the float-charge mode, the battery charger is shut off for ten seconds, which simulates an ac outage and tests the battery. If the battery voltage drops too quickly, the test is aborted and the DTFAIL Relay Word bit asserts. If the battery voltage is okay throughout the test period, the battery charger is turned back on.

Once the battery fails an automatic load test, automatic testing is no longer performed unless the battery tests successfully via one of the following described means (SELOGIC or serial port), or the battery is replaced.

Front-Panel Battery Load Test

Factory-Default Front-Panel Battery Load Test in Section 8: Metering and Monitoring in the SEL-651RA Recloser Control Instruction Manual details a front-panel battery load test capability that comes as a factory-default configuration for the SEL-651RA recloser control. Similar setting can be made for the SEL-651R-2 to realize such a battery load test capability with a front-panel operator pushbutton and the front-panel display. This capability came available for the SEL-651R-2 with the introduction of the DISTST Relay Word bit.

SELOGIC Battery Load Test

NOTE: If the TESTBATT equation is held in a continually asserted state (= logical 1), this will not impede initiation of the automatic battery load test nor the battery load test via serial port.

The Request Battery Test (TESTBATT) SELOGIC control equation is provided for entry of user-defined battery load test conditions. this function is useful for initiating a battery test from the front panel, at a set time of day, or remotely. This SELOGIC control equation is rising-edge qualified, meaning that it will only initiate a battery test when its state changes from logical 0 to 1. This prevents an asserted condition from continually initiating battery tests. Following a valid rising edge of the TESTBATT equation, the SEL-651R-2 will initiate a battery test if *all* of the following conditions are met.

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➤ There is no battery test currently in progress.

➤ Battery charger is NOT in Discharge (ac off) or Startup (relay is starting up) mode.

➤ There have not been more than four battery tests in the last hour.

Battery Load Test via Serial Port

View the results of a battery test or request a new battery test by using the **BTT** or **BTT NOW** commands at the serial port.

See *BTT Command on page 10.41* for required serial port access levels and sample screen captures.

Battery Status

Check the battery status in several ways. On the front panel (with factory-default front-panel settings), the **BATTERY PROBLEM** LED (see *Figure 11.13*) illuminates when Relay Word bit BTFAIL is asserted. BTFAIL asserts for either of the following battery problems:

➤ Load test failure (Relay Word bit DTFAIL = logical 1)

➤ Cannot charge or is otherwise internally damaged

Use the STATUS menu on the front panel of the SEL-651R-2 to access more battery status information. Use the **Up Arrow** and **Down Arrow** pushbuttons to move to different status screens. Those status elements of interest for the battery are the following.

INPBV =	Input Power Bus Voltage (Vdc)
12VAUX =	12V Auxiliary Bus Voltage (Vdc)
MODE =	Battery Charger Mode
	STARTUP = Startup
	CUR_CHG = Constant Current Charge
	FST_CHG = Fast Charge
	FLT_CHG = Float Charge
	DISCHRG = Discharge
	BAT_FLR = Battery Failure
	BAT_TST = Battery Discharge Test
VBAT =	Battery Voltage (Vdc)
IBAT =	Battery Current (A dc, discharge if negative)
TCCAPV =	Trip/Close Capacitor Voltage (Vdc)

The same battery status information as described above is also available via serial port communications by using the **STATUS** command.

The battery voltage "VBAT" is also available as an analog quantity for use in the Load Profile Recorder (see *Table G.1*).

Include VBAT in the LDLIST setting (using the **SET R** command; see *Section 9: Settings*) to record the battery performance during source outages (see *Load Profile Report on page 8.44*).

Use the Sequential Events Recorder (see *Sequential Events Recorder (SER) on page 12.2*) to determine the moment that the power source outage began and ended, and the Load Profile Report to check the battery performance during the source outage.

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Load Profile Report

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Modifying Reclosing Logic

In addition to alarming, the recloser control elements associated with the battery and charging system can provide control functions such as disabling or blocking reclosing. For example, the factory-default logic settings include one of these following automatic reclose supervision settings:

Traditional
Retrofit reclosers: 79CLS3P := PWR_SRC1 AND TCCAP AND NOT(BTFAIL)

Other reclosers: 79CLS3P := TCCAP AND NOT(BTFAIL)

This is for three-phase trip applications (Group setting ESPB := N).

This SELOGIC control equation permits automatic reclosing to proceed after a reclose interval time out only if *all* the following conditions are present:

➤ (Traditional Retrofit reclosers only.) The AC voltage source is present; PWR_SRC1 = logical 1. This assumes the traditional installation where the low-voltage ac close power is wired to the same phase as the SEL-651R-2 power supply input (see *Figure 2.40*).

➤ The Trip and Close Capacitors are fully charged; TCCAP = logical 1.

➤ The Battery is healthy; BTFAIL = logical 0.

This is a factory-default setting because recloser tripping and closing require dc battery energy. Therefore, if the battery or charging system is not functioning properly, the control should not reclose after a trip because there might not be enough dc battery energy to trip again after a reclose.

Load Profile Report

The SEL-651R-2 Load Profile Recorder is capable of recording as many as 15 selectable analog quantities at a periodic rate and storing the data in a report in nonvolatile memory.

The load profile report is available via serial port communications by using the **LDP** command (see *LDP Command (Load Profile Report) on page 10.55*).

At the interval given by load profile acquisition rate setting LDAR, the recloser control adds a record to the load profile buffer. This record contains the time stamp, the present value of each of the analog quantities listed in the load profile list setting LDLIST, and a checksum. These settings are made and reviewed with the **SET R** and **SHO R** serial port commands, respectively. Setting LDAR can be set to any of the following values: 5, 10, 15, 30, and 60 minutes. Setting LDLIST may contain any of the quantities that are marked in the Load Profile column of *Table G.1* (see *Report Settings on page SET.64*).

Labels are entered into the setting as either comma or space delimited, but are displayed as comma delimited. Load profiling is disabled if the LDLIST setting is empty (i.e., set to NA or 0), which is displayed as LDLIST := 0. The load buffer is stored in nonvolatile memory and the acquisition is synchronized to the time of day, with a resolution of ±5 seconds. Changing the LDAR setting may result in as many as two acquisition intervals before resynchronization occurs. If the LDAR setting is increased, the next acquisition time does not have a complete interval; therefore, no record is

saved until the second acquisition time, which is a complete cycle. When the buffer fills up, newer records overwrite older records. The recloser control is able to store at least 26 days of data when LDAR = 5 minutes, assuming all 15 values are used. If less than 15 values are specified, the recloser control will be able to store more days of data before data overwrite occurs. Likewise, if the interval is set longer, the recloser control will be able to store more days of data before data overwrite occurs.

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Section 9

Settings

Introduction

The SEL-651R-2 Recloser Control stores customer-entered settings in nonvolatile memory. Settings are divided into the following six setting classes:

1. Global

2. Group *n* (where *n* = 1–8)

3. Logic *n* (where *n* = 1–8)

4. Front Panel

5. Report

6. Port *p* (where *p* = 1, 2, 3, F(4), or 5)

Some setting classes have multiple instances. In the above list, there are eight settings groups for Group and Logic settings, and five Port setting instances (one for each of the four serial ports and one for Ethernet Port 5).

Settings may be viewed or set in several ways, as shown in *Table 9.1*.

Table 9.1   Methods of Accessing Settings

	Serial Port Commands	**Front-Panel HMI Set/Show Menu**	**QuickSet (PC software)**
Display Settings	All settings (**SHO** command)	Some settings[a,b]	All settings
Change Settings	All settings (**SET** command)	Some settings[a,b]	All settings

[a] Only Global, Group, Front-Panel, and Port setting classes can be accessed.
[b] SELogic control equations can only be viewed, not set, on the HMI.

See *Factory-Default Settings on page 9.61* for examples of the **SHO** command, including the factory-default settings.

The **SET** command is described in the next subsection. *Table 9.2* lists the settings classes with a brief description and the page numbers for the *Settings Sheets* included at the end of this section. The order of the setting sheets matches the numbered list above.

See *SET/SHOW Menu on page 11.12* for details on accessing settings via the front-panel HMI. See *Section 3: PC Software* for ACSELERATOR QuickSet SEL-5030 Software information.

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Table 9.2   Serial Port SET Commands

Command	Settings Type	Description	Settings Sheets[a]
SET G	Global	System configuration, current and voltage connection settings, input debounce timers, breaker monitor, etc.	*SET.1–SET.7*
SET *n*	Group	Overcurrent and voltage elements, reclosing relay, tripping, closing, etc., for Settings Group *n* (n = 1, 2, 3, 4, 5, 6, 7, 8)	*SET.7–SET.37*
SET L *n*	Logic	General logic settings for Settings Group *n* (n = 1, 2, 3, 4, 5, 6, 7, 8)	*SET.38–SET.54*
SET F	Front-Panel	Front-panel default display, pushbutton and target LED settings, display points, and local control bits	*SET.54–SET.63*
SET R	Report	Sequential Events Recorder (SER) trigger conditions, event report settings, and Load Profile Recorder (LDP) settings	*SET.64*
SET P *n*	Port	Port *n* settings n = 1: EIA-485 serial port n = 2, 3, or F: EIA-232 serial ports n = 5: single or dual Ethernet options	*SET.65–SET.76*
SET D *n*	DNP3	DNP3 Map *n* settings (n = 1, 2, or 3)	See *Appendix E*
SET M	Modbus	Modbus map settings	See *Appendix K*

a Located at the end of this section.

NOTE: Although there is no dedicated settings class for the USB port, the Port F settings class contains two settings that affect the USB port (see Port Enable Settings (SET P n Command) on page 9.60).

View settings with the respective serial port **SHOW** commands (**SHO G**, **SHO**, **SHO L**, **SHO F**, **SHO R**, **SHO P**) (see *SHO Command (Show/View Settings) on page 10.68*).

Make Global Settings (SET G) First

For most applications, make Global settings (see *Global Settings on page SET.1*) before making the Group settings. Changing some of the Global settings can cause certain Group settings to be hidden from view or forced to default values. The Global settings, in general, define the overall physical connections and equipment type, while the Group settings define the application-specific details.

The SEL-651R-2 will display a specific warning message before allowing a Global setting to be changed that would affect Group settings. These warnings are shown in *Settings Explanations on page 9.27*.

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Settings 9.3
Settings Changes Via the Serial Port

Settings Changes Via the Serial Port

See *Section 10: Communications* for information on serial port communications and recloser control access levels. The **SET** commands in *Table 9.2* operate at Access Level 2 (screen prompt: =>>). To change a specific setting, enter the command:

> **SET** *c n s* **TERSE**

where:

c =	class (G, 1–8, L, F, R, P, D, or M): Choices 1–8 select the Group (relay) settings 1 through 8. If class is not specified, the relay selects the Group settings for the active settings group.
n =	instance number (only valid for Class L, P, and D): (1–8) for *c*= L (Logic) class. If *n* is not specified, the relay selects the Logic settings from the active settings group. (1, 2, 3, 5, or F) for *c* = P (port) class. If *n* is not specified, the relay selects the present port. If this session is via the USB port, *n* must be specified. (1–3) for *c* = D (DNP3) class. If *n* is not specified, the relay selects DNP3 Map 1.
s =	the name of the specific setting you wish to jump to and begin setting. If *s* is not entered, the recloser control starts at the first setting.
TERSE =	instructs the SEL-651R-2 to skip the SHOW display after the last setting. Use this parameter to speed up the **SET** command. If you wish to review the settings before saving, do not use the **TERSE** option.

When you issue the **SET** command, the SEL-651R-2 presents a list of settings, one at a time. Enter a new setting, or press **<Enter>** to accept the existing setting. Editing keystrokes are shown in *Table 9.3*.

Table 9.3   Set Command Editing Keystrokes

Press Key(s)	Results
<Enter>	Retains setting and moves to the next setting.
^ <Enter>	Returns to previous setting.
< <Enter>	Returns to previous setting section.
> <Enter>	Moves to next setting section.
END <Enter>	Exits editing session, then prompts you to save the settings.
<Ctrl + X>	Aborts editing session without saving changes.

The recloser control checks each entry to ensure that it is within the setting range. If it is not, an Out of Range message is generated and the recloser control prompts for the setting again.

If a given setting is beyond 80 characters (like an SER trigger list setting, set with **SET R** command), then a backslash (\) and carriage return have to be made to complete the setting on the next line. The backslash does not have to be entered right at character position 81—it can be entered earlier and then the setting continued on the next line.

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When all the settings are entered, the recloser control displays the new settings and prompts for approval to enable them. Answer **Y <Enter>** to enable the new settings.

The SEL-651R-2 handles settings changes as shown in *Table 9.4*.

Table 9.4   Settings Changes Effects (SALARM Relay Word Bit, ENABLED LED, SER)

Settings Change	SALARM Relay Word Bit Pulsed for Approximately 1 Second?	ENABLED LED Extinguished for a Few Seconds?	Sequential Events Recorder (SER) "Settings Changed" Entry?
Global	Yes	Yes	Yes
Active Group	Yes	Yes	Yes
Inactive Group	Yes	No	Yes
Active Logic	Yes	Yes	Yes
Inactive Logic	Yes	No	Yes
Front Panel	Yes	Yes	Yes
Report	Yes	Yes	Yes
Port (any)	Yes	Yes	Yes
Copy from active to inactive group	Yes	No	Yes
Copy from inactive to active group	Yes	Yes	Yes
Group Change	Yes	Yes (less than 1 second)	Yes[a]

[a] SER entry for a group Change is "Group Changed."

In *Table 9.4*, an inactive group is one of the seven settings groups that is not the currently active group. For example, if Settings Group 2 is currently active, Settings Groups 1, 3, 4, 5, 6, 7, and 8 are inactive. A **SET L 4** command represents a change to Logic settings in inactive Settings Group 4.

The SALARM Relay Word bit is in the factory-default setting for OUT201. The SALARM Relay Word bit is driven by the Global SELOGIC control equation setting SALARM. The behavior of the SALARM Relay Word bit in *Table 9.4* presupposes factory-default settings for SELOGIC setting SALARM (see *Factory-Default Settings on page 9.61*).

If the **ENABLED** LED is extinguished, then SEL-651R-2 protection functions are disabled.

The SER is described in *Section 12: Analyzing Events*.

Time-Overcurrent Curves

Standard Inverse-Time Characteristic Curves

The information in *Table 9.5* and *Table 9.6* describes the curve timing for the curve and time-dial settings made for the time-overcurrent elements (see *Figure 4.16–Figure 4.24*). The time-overcurrent curves in *Figure 9.1– Figure 9.5* conform to IEEE Std C37.112-1996 (R2001) IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays.

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where:

T_p = Operating time in seconds

T_R = Electromechanical induction-disk emulation reset time in seconds (if you select electromechanical reset setting)

TD = Time-dial setting

M = Applied multiples of pickup current (for operating time [T_p], M > 1; for reset time [T_R], M ≤ 1)

Table 9.5   Equations Associated With U.S. Curves

Curve Type	Operating Time	Reset Time	Figure
U1 (Moderately Inverse)	$T_p = TD \cdot \left(0.0226 + \dfrac{0.0104}{M^{0.02} - 1} \right)$	$T_R = TD \cdot \left(\dfrac{1.08}{1 - M^2} \right)$	*Figure 9.1*
U2 (Inverse)	$T_p = TD \cdot \left(0.180 + \dfrac{5.95}{M^2 - 1} \right)$	$T_R = TD \cdot \left(\dfrac{5.95}{1 - M^2} \right)$	*Figure 9.2*
U3 (Very Inverse)	$T_p = TD \cdot \left(0.0963 + \dfrac{3.88}{M^2 - 1} \right)$	$T_R = TD \cdot \left(\dfrac{3.88}{1 - M^2} \right)$	*Figure 9.3*
U4 (Extremely Inverse)[a]	$T_p = TD \cdot \left(0.02434 + \dfrac{5.64}{M^2 - 1} \right)$	$T_R = TD \cdot \left(\dfrac{5.64}{1 - M^2} \right)$	*Figure 9.4*
U5 (Short-Time Inverse)	$T_p = TD \cdot \left(0.00262 + \dfrac{0.00342}{M^{0.02} - 1} \right)$	$T_R = TD \cdot \left(\dfrac{0.323}{1 - M^2} \right)$	*Figure 9.5*

[a] U.S. Curve U4 differs slightly from the SEL-351R Recloser Control and SEL-351 Relay family U4 curves.

Table 9.6   Equations Associated With IEC Curves

Curve Type	Operating Time	Reset Time	Figure
C1 (Standard Inverse)[a]	$T_p = TD \cdot \dfrac{0.14}{M^{0.02} - 1}$	$T_R = TD \cdot \left(\dfrac{13.5}{1 - M^2} \right)$	*Figure 9.6*
C2 (Very Inverse)[a]	$T_p = TD \cdot \dfrac{13.5}{M - 1}$	$T_R = TD \cdot \left(\dfrac{47.3}{1 - M^2} \right)$	*Figure 9.7*
C3 (Extremely Inverse)[a]	$T_p = TD \cdot \dfrac{80}{M^2 - 1}$	$T_R = TD \cdot \left(\dfrac{80}{1 - M^2} \right)$	*Figure 9.8*
C4 (Long-Time Inverse)	$T_p = TD \cdot \dfrac{120}{M - 1}$	$T_R = TD \cdot \left(\dfrac{120}{1 - M} \right)$	*Figure 9.9*
C5 (Short-Time Inverse)	$T_p = TD \cdot \dfrac{0.05}{M^{0.04} - 1}$	$T_R = TD \cdot \left(\dfrac{4.85}{1 - M^2} \right)$	*Figure 9.10*

[a] Recloser curves 200–202 are equivalent to IEC curves as follows: 200 = IEC Standard Inverse (C1), 201 = IEC Very Inverse (C2), 202 = IEC Extremely Inverse (C3).

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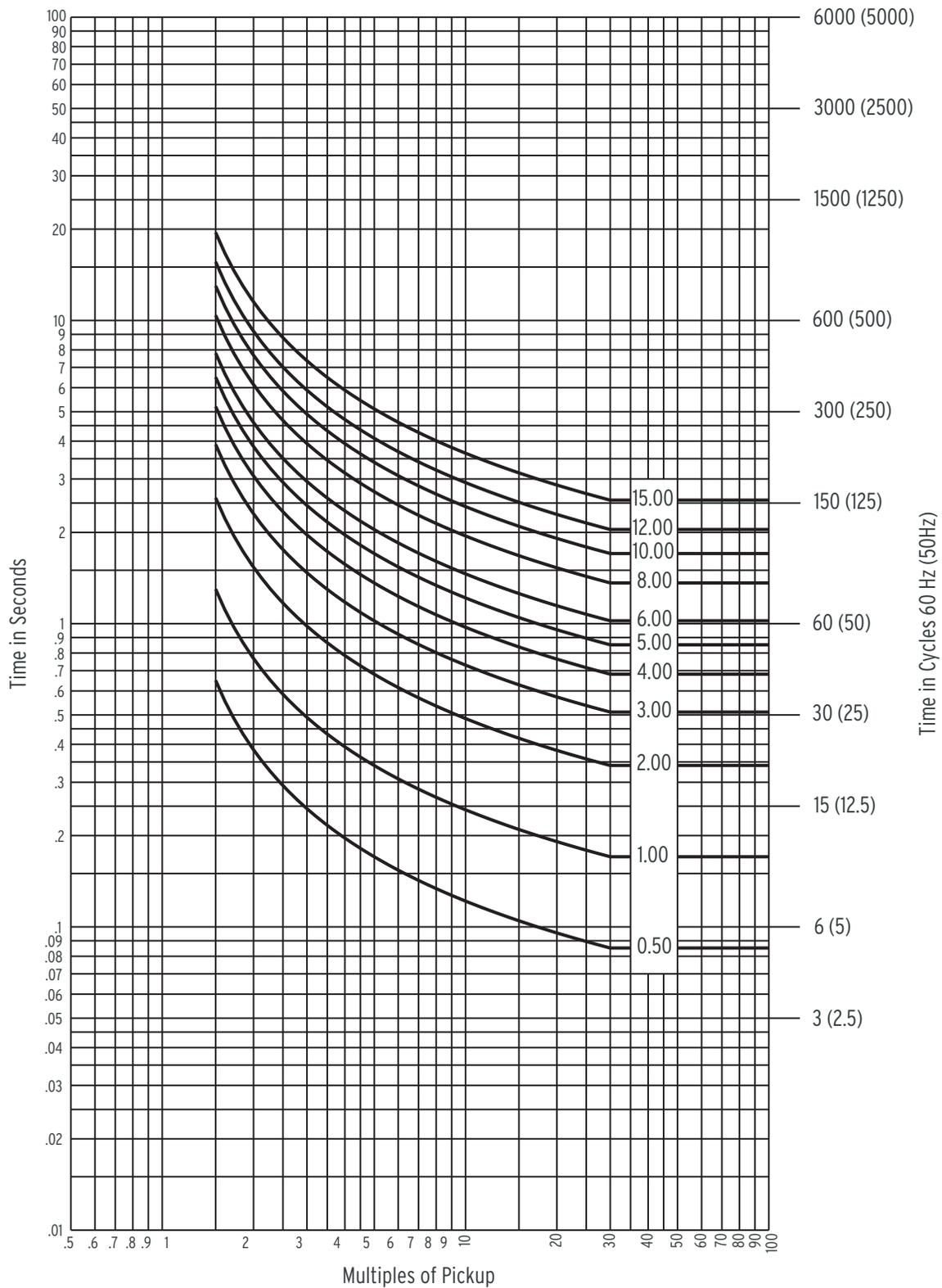
Figure 9.1   U.S. Moderately Inverse Curve: U1
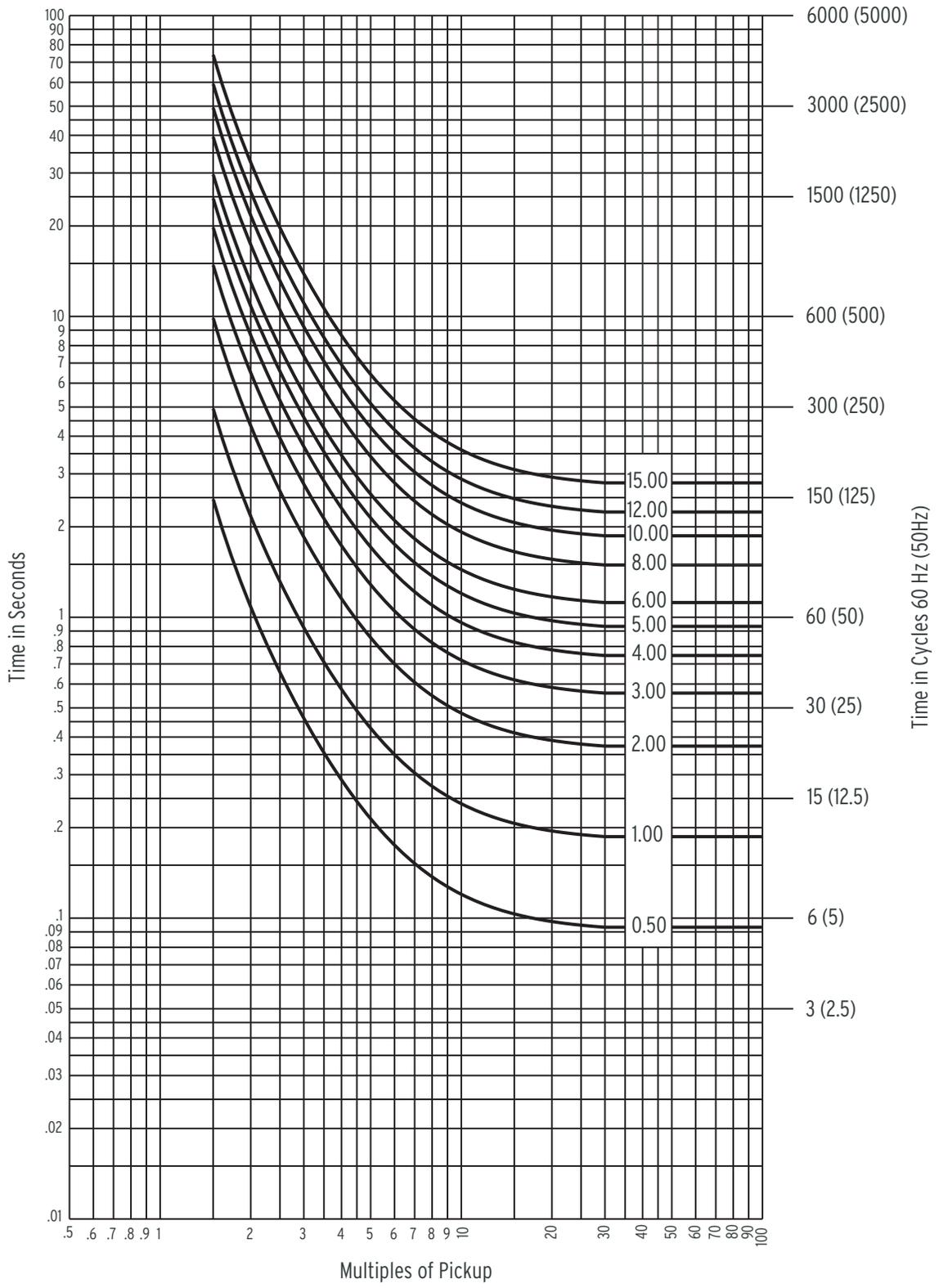
Figure 9.2   U.S. Inverse Curve: U2

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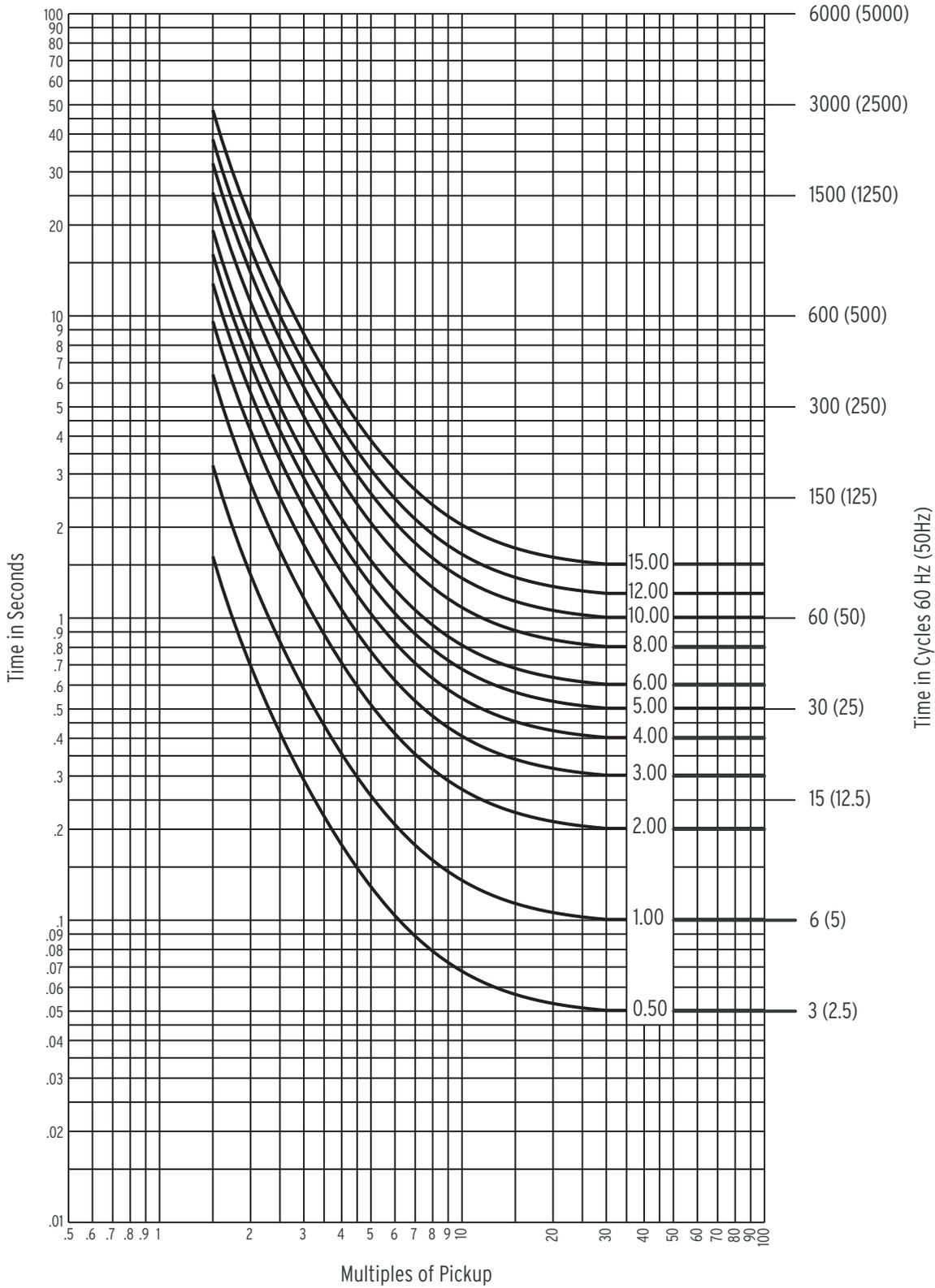
Figure 9.3   U.S. Very Inverse Curve: U3

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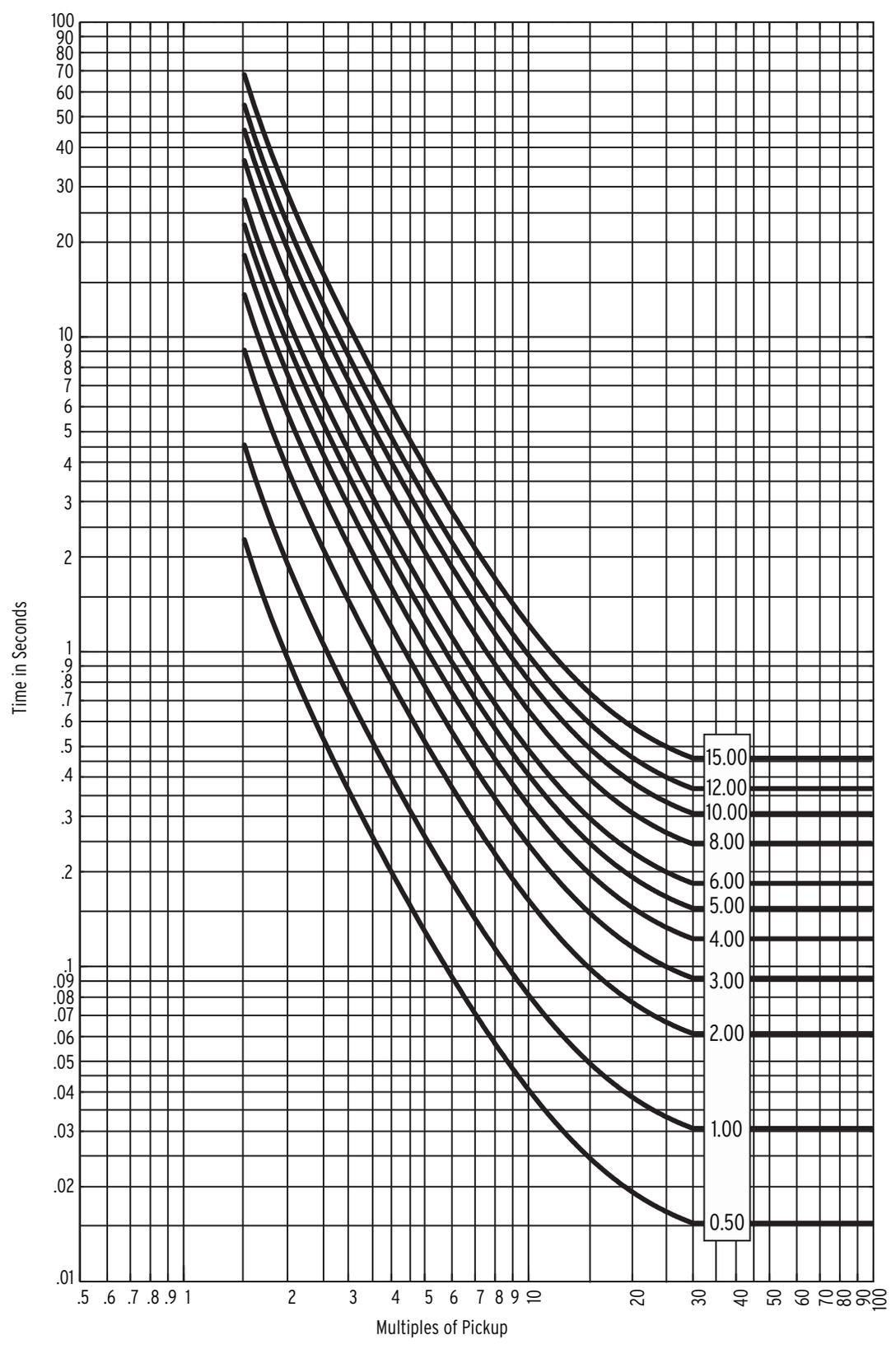
Figure 9.4   U.S. Extremely Inverse Curve: U4

9.10 | Settings
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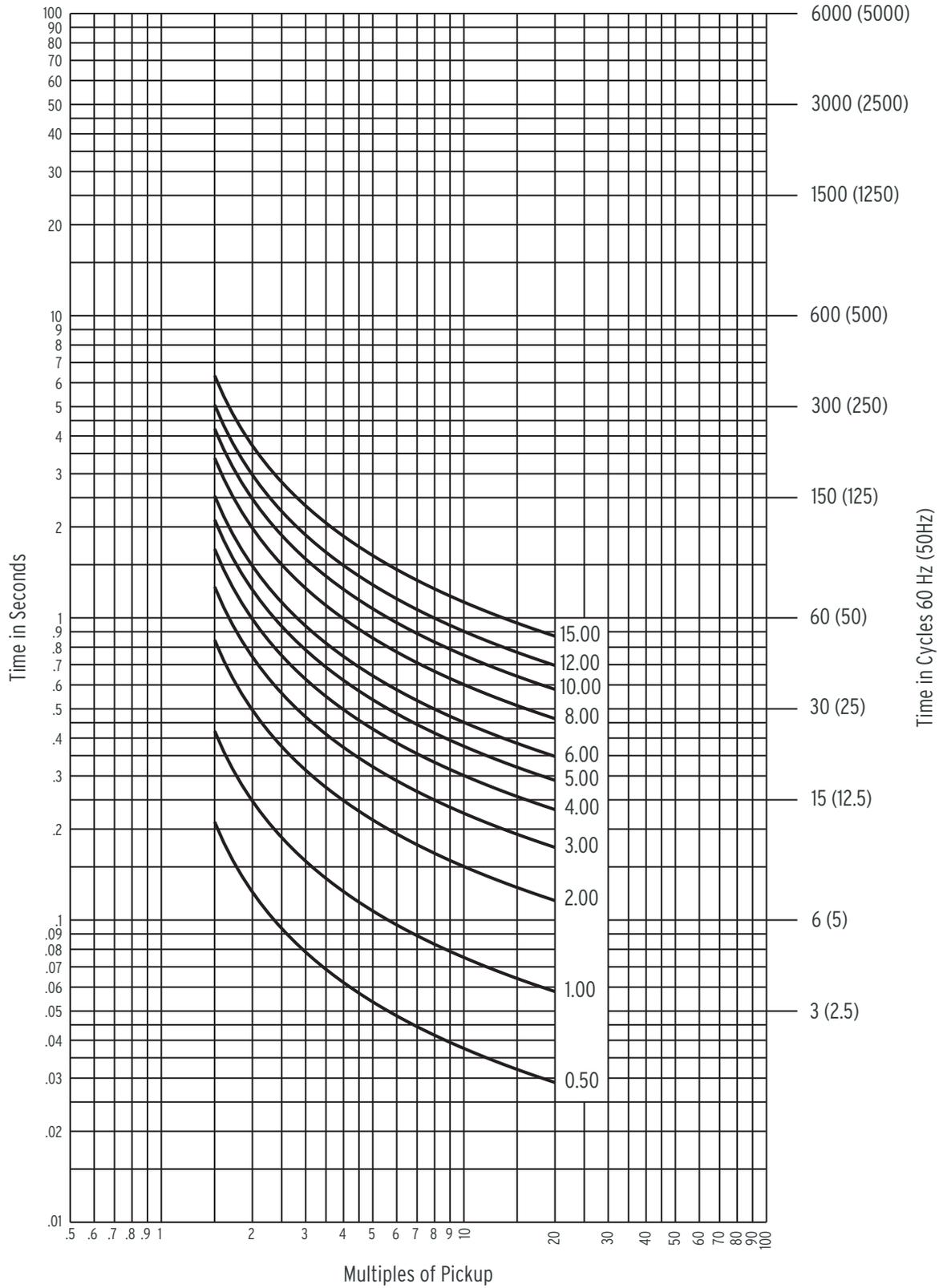
Figure 9.5   U.S. Short-Time Inverse Curve: U5
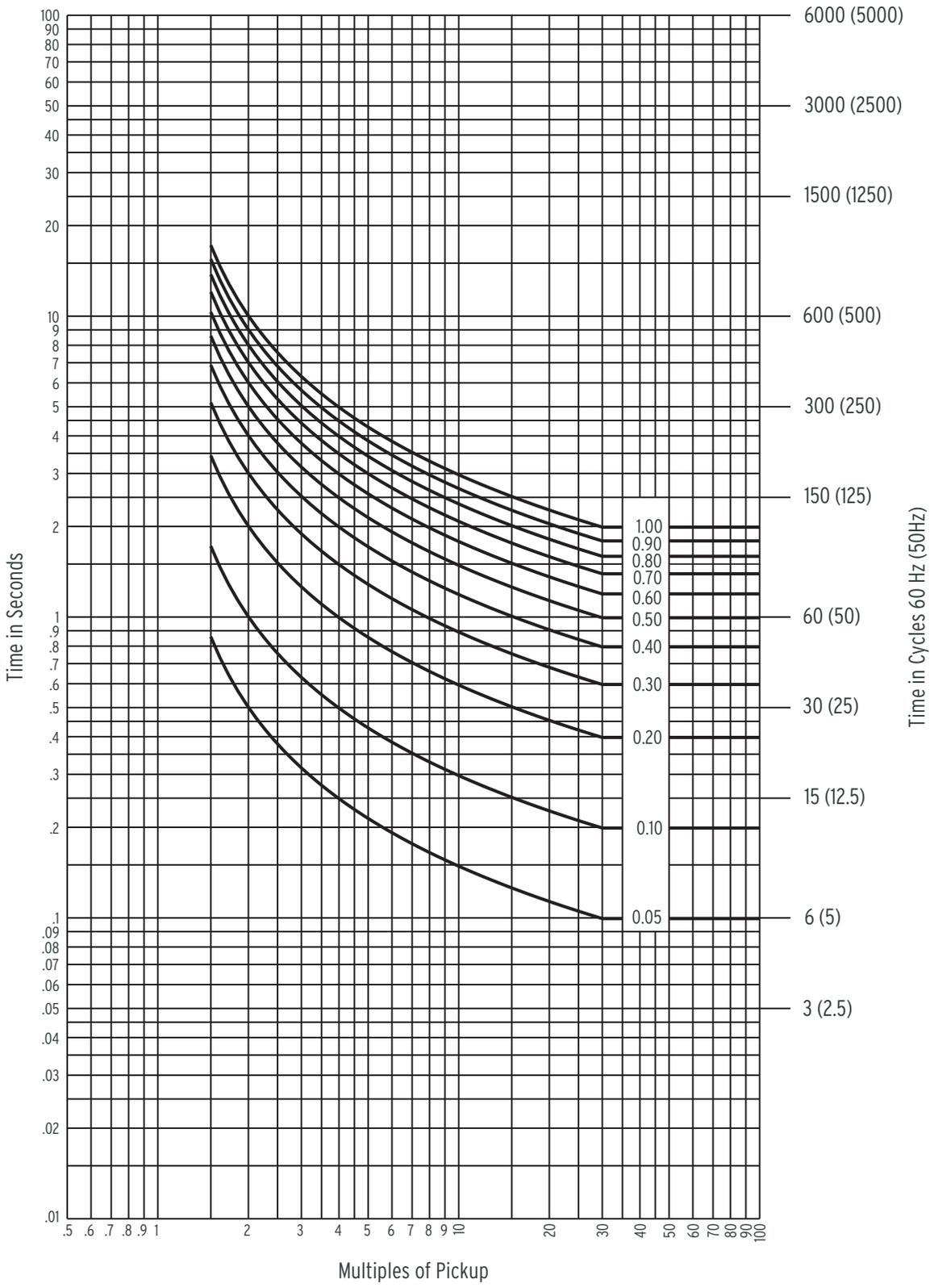
Figure 9.6   IEC Class A Curve (Standard Inverse): C1

9.12 | Settings
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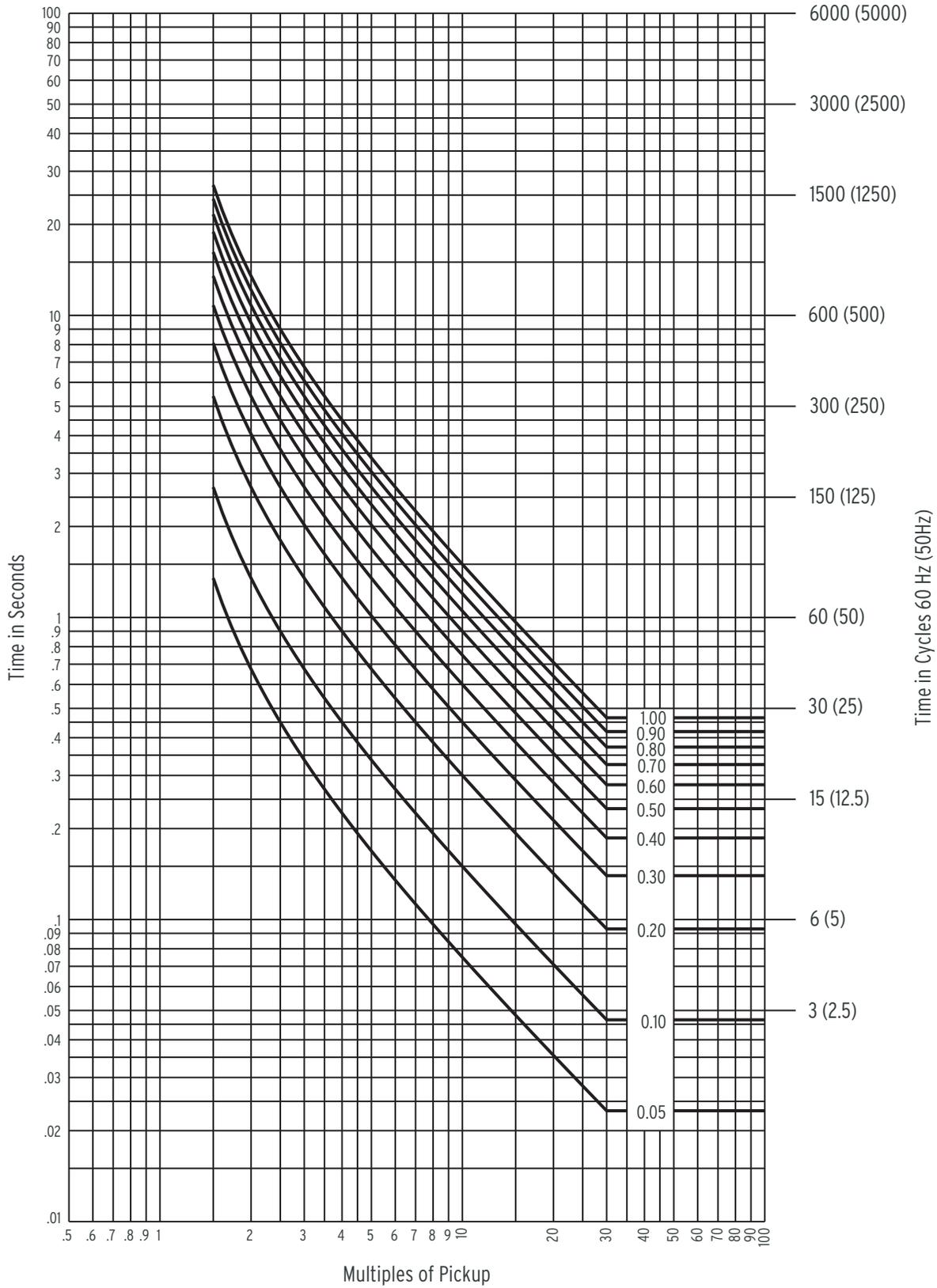
Figure 9.7   IEC Class B Curve (Very Inverse): C2

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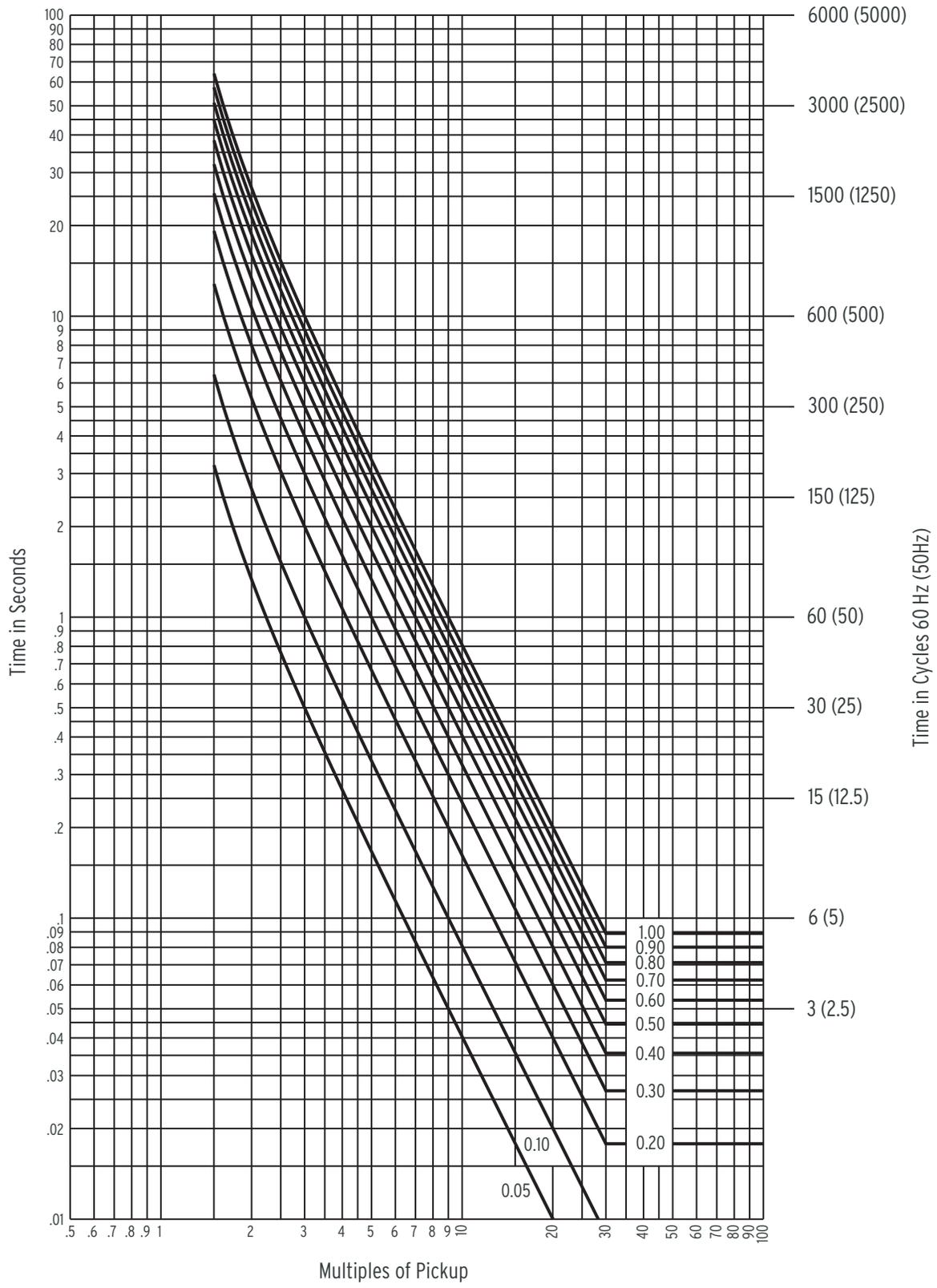
Figure 9.8   IEC Class C Curve (Extremely Inverse): C3

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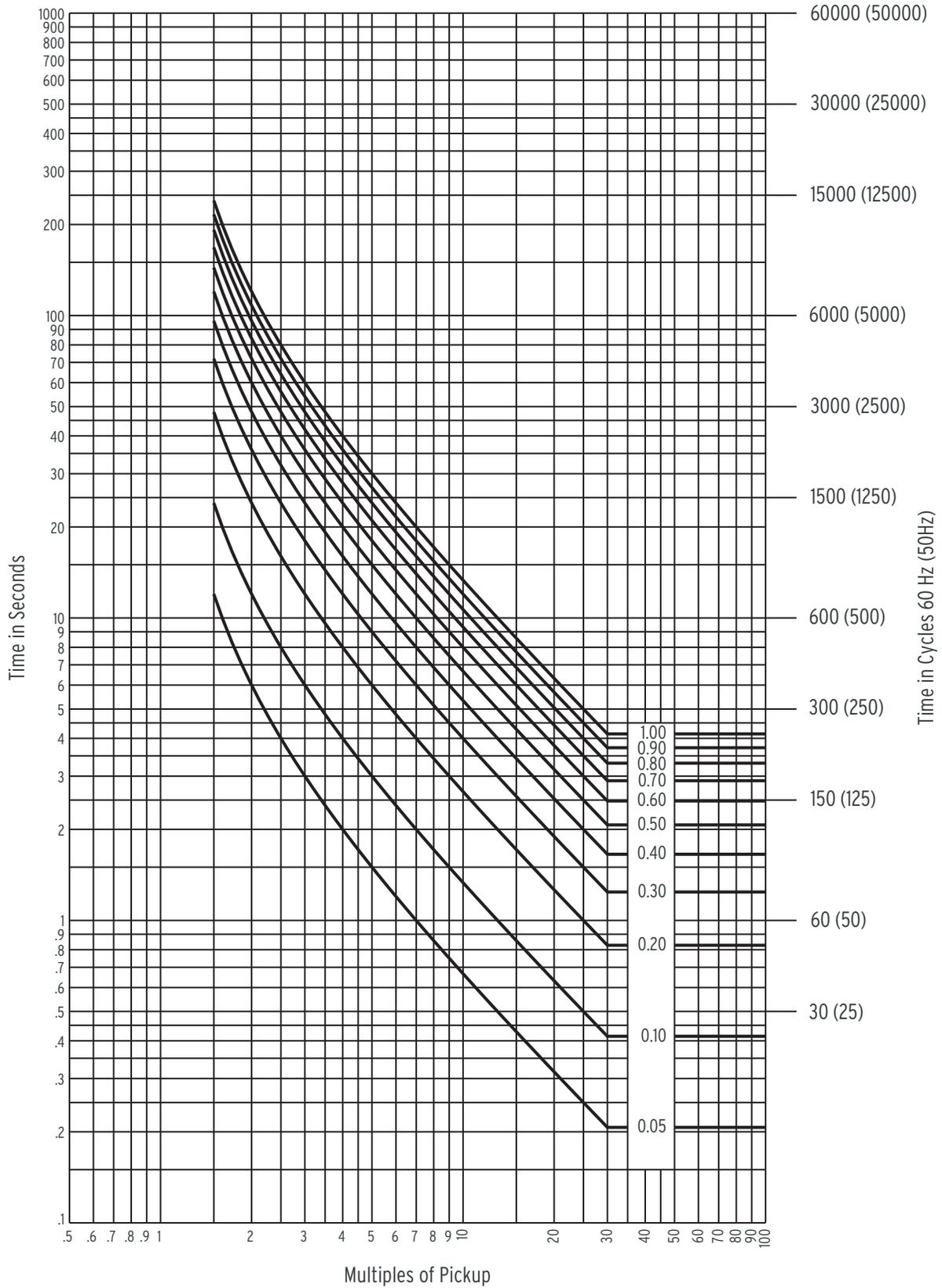
Figure 9.9   IEC Long-Time Inverse Curve: C4

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Figure 9.1O   IEC Short-Time Inverse Curve: C5

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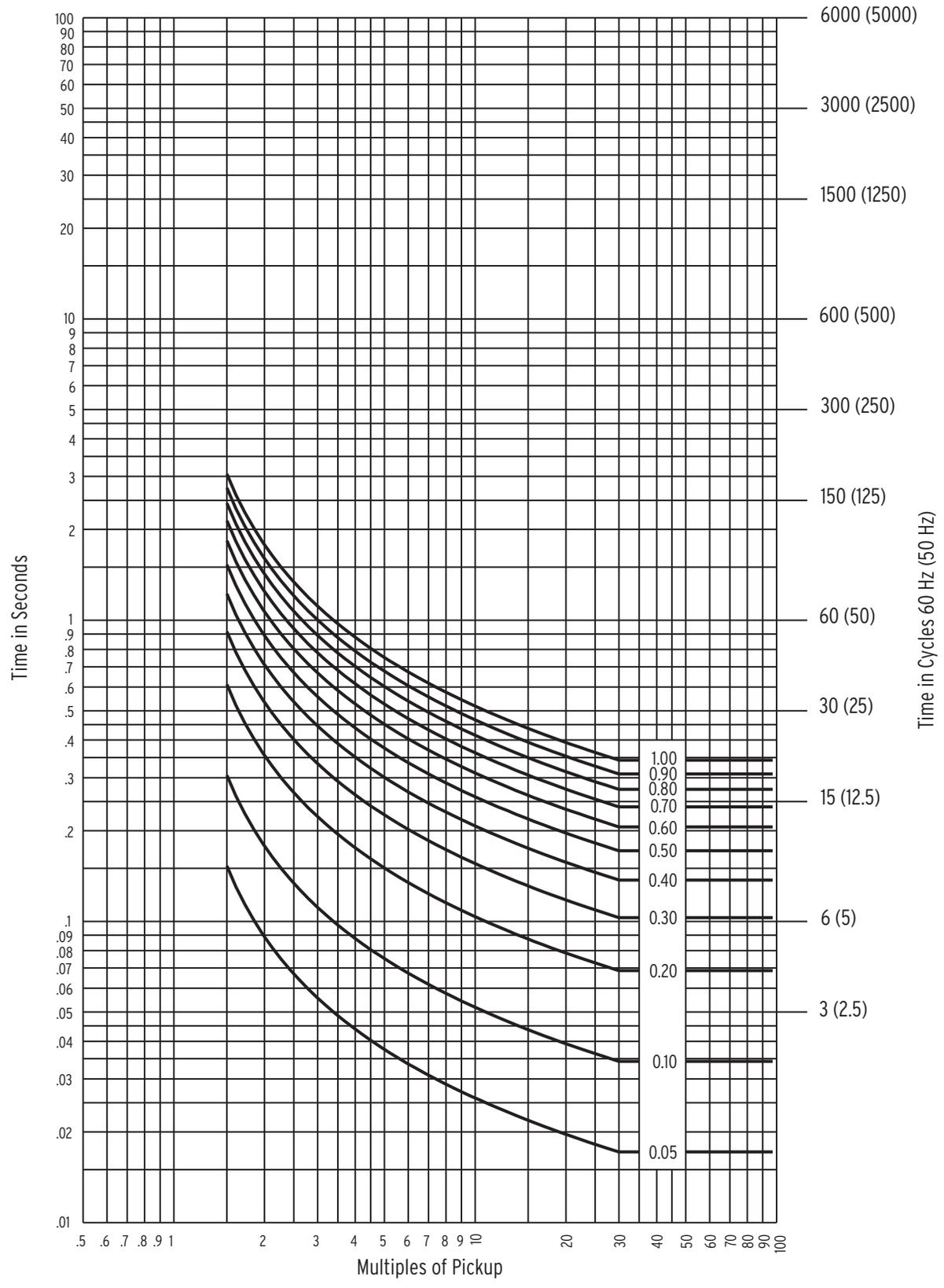
Recloser Curves

Traditional recloser curves are available for the time-overcurrent elements (see *Figure 4.16–Figure 4.24*). The recloser curves in *Figure 9.11–Figure 9.20* can be specified with either the older electronic recloser control designation or the newer micro-processor-based recloser control designation (see *Table 9.7*). For example, a given recloser curve has the following two designations:

➤ Older electronic recloser control designation: A

➤ Newer microprocessor-based recloser control designation: 101

Recloser curve A and curve 101 are the same curve—use either designation in making curve settings in the SEL-651R-2.

The recloser curves have a time-dial setting range of 0.10 to 2.00, as is available in traditional microprocessor-based recloser controls. In traditional microprocessor-based recloser controls, the time-dial setting is often referred to as a "vertical multiplier" setting instead.

The recloser curves in *Figure 9.11–Figure 9.20* are shown with an effective time-dial setting of 1.00.

NOTE: The electromechanical reset setting is not available with recloser curves. It is only available with traditional electromechanical time-overcurrent relay curves (U1–U5 and C1–C5). See Table 4.3 and Table 4.5–Table 4.8 for further information.

Table 9.7   Recloser Curve Designations

Recloser Curve Cross Reference—Old to New					
Old	**New**	**Reference**	**Old**	**New**	**Reference**
A	101	*Figure 9.11*	Z	134	*Figure 9.17*
B	117	*Figure 9.12*	1	102	*Figure 9.14*
C	133	*Figure 9.11*	2	135	*Figure 9.12*
D	116	*Figure 9.13*	3	140	*Figure 9.12*
E	132	*Figure 9.16*	4	106	*Figure 9.19*
F	163	*Figure 9.14*	5	114	*Figure 9.17*
G	121	*Figure 9.15*	6	136	*Figure 9.15*
H	122	*Figure 9.14*	7	152	*Figure 9.20*
J	164	*Figure 9.14*	8	113	*Figure 9.20*
KP	162	*Figure 9.18*	8PLUS	111	*Figure 9.13*
L	107	*Figure 9.20*	9	131	*Figure 9.19*
M	118	*Figure 9.18*	KG	165	*Figure 9.17*
N	104	*Figure 9.11*	11	141	*Figure 9.19*
P	115	*Figure 9.16*	13	142	*Figure 9.15*
R	105	*Figure 9.12*	14	119	*Figure 9.19*
T	161	*Figure 9.18*	15	112	*Figure 9.20*
V	137	*Figure 9.15*	16	139	*Figure 9.13*
W	138	*Figure 9.11*	17	103	*Figure 9.18*
Y	120	*Figure 9.17*	18	151	*Figure 9.16*

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Settings 9.17
Time-Overcurrent Curves
Wolfe
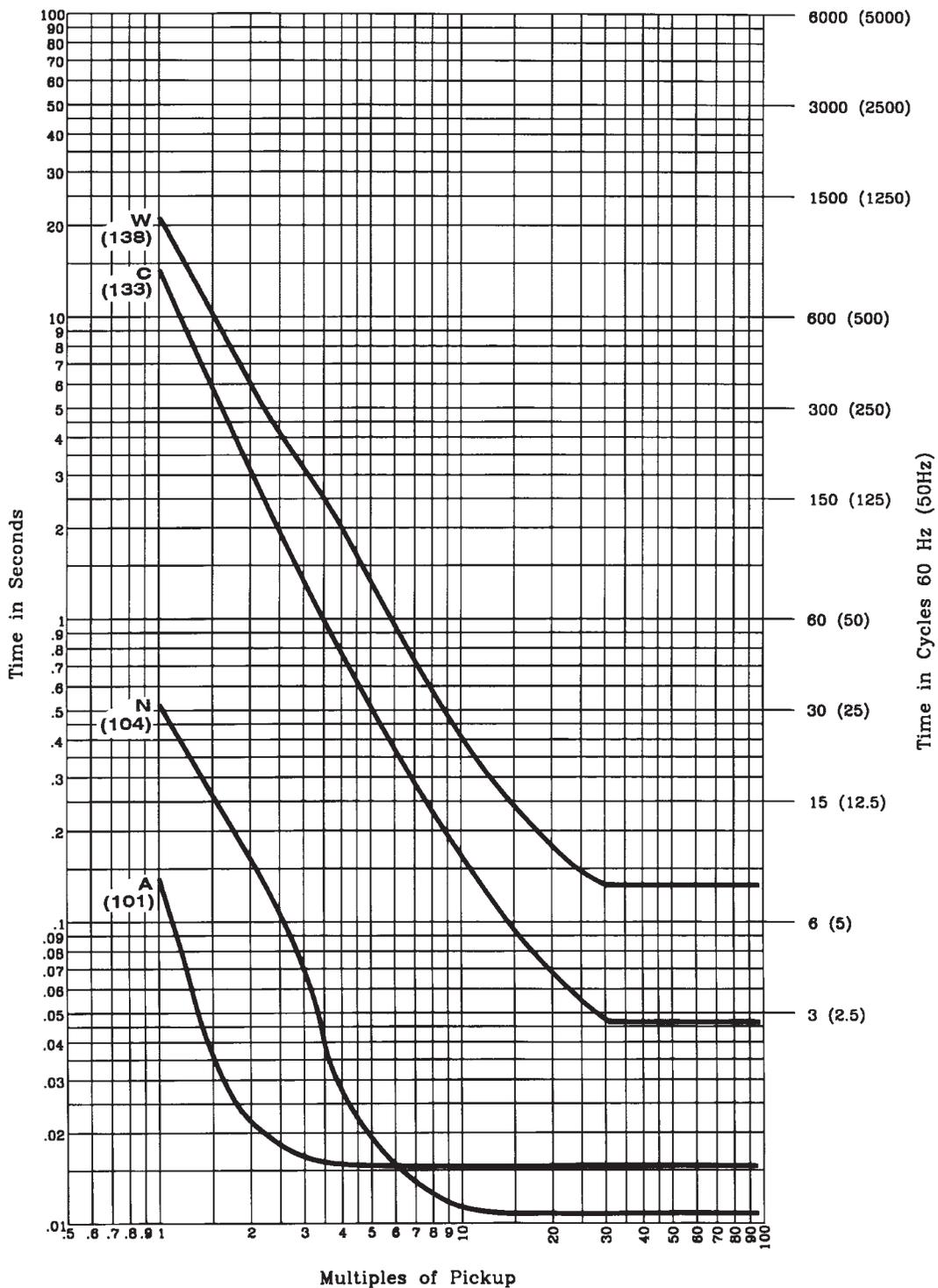
RECLOSER CONTROL TIME OVERCURRENT CURVES

DWG. NO. TOC1005
DATE: 25 JUN 98
RECLOSER CURVE 1
DECADE SCALE 2.213

Figure 9.11   Recloser Control Response Curves A, C, N, and W

9.18 | Settings
Time-Overcurrent Curves

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Wolfe
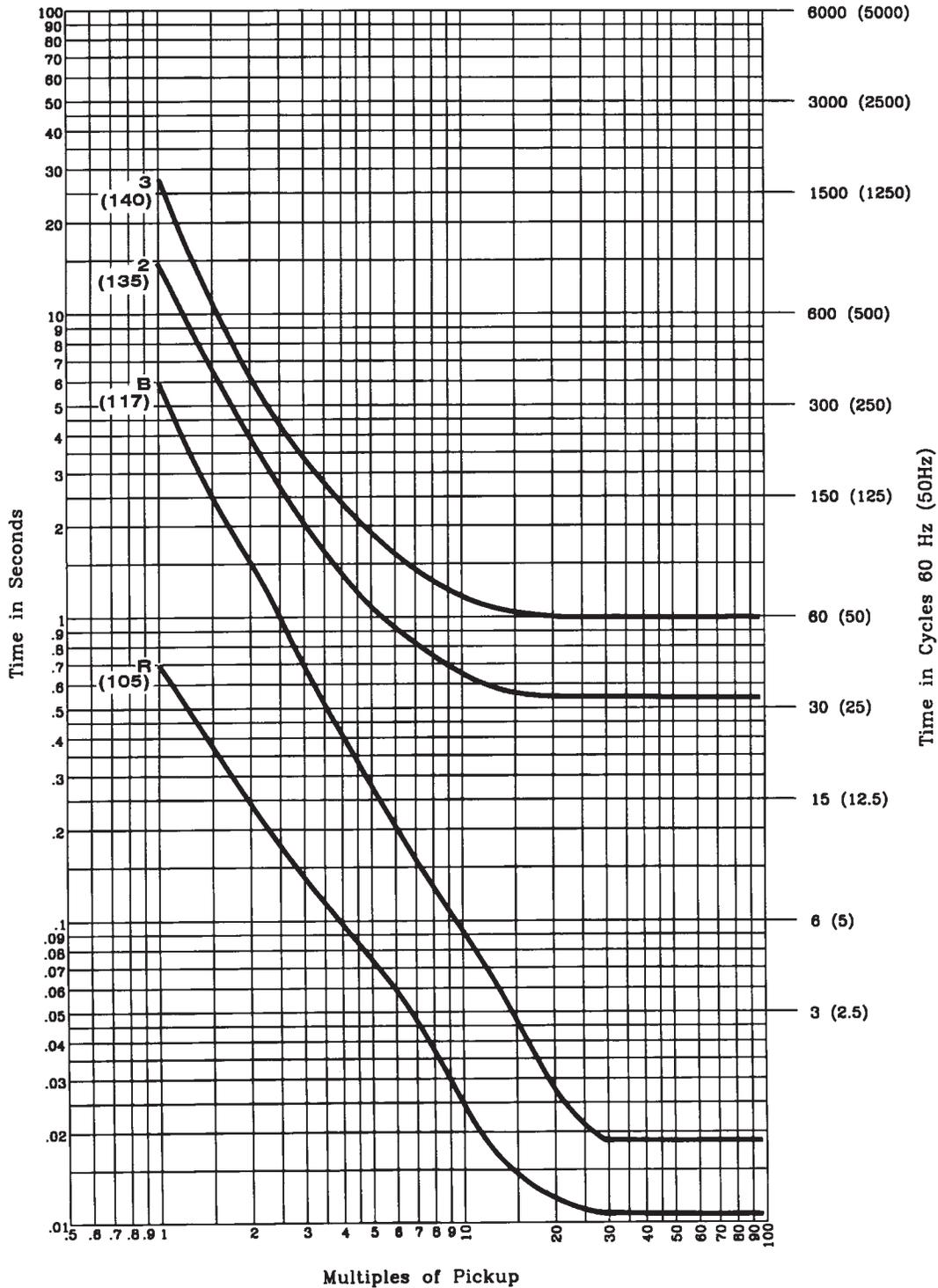
RECLOSER CONTROL TIME OVERCURRENT CURVES

DWG. NO. TOC1006
DATE: 25 JUN 98
RECLOSER CURVE 2
DECADE SCALE 2.213

Figure 9.12   Recloser Control Response Curves B, R, 2, and 3

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9.19
Settings
Time Overcurrent Curves
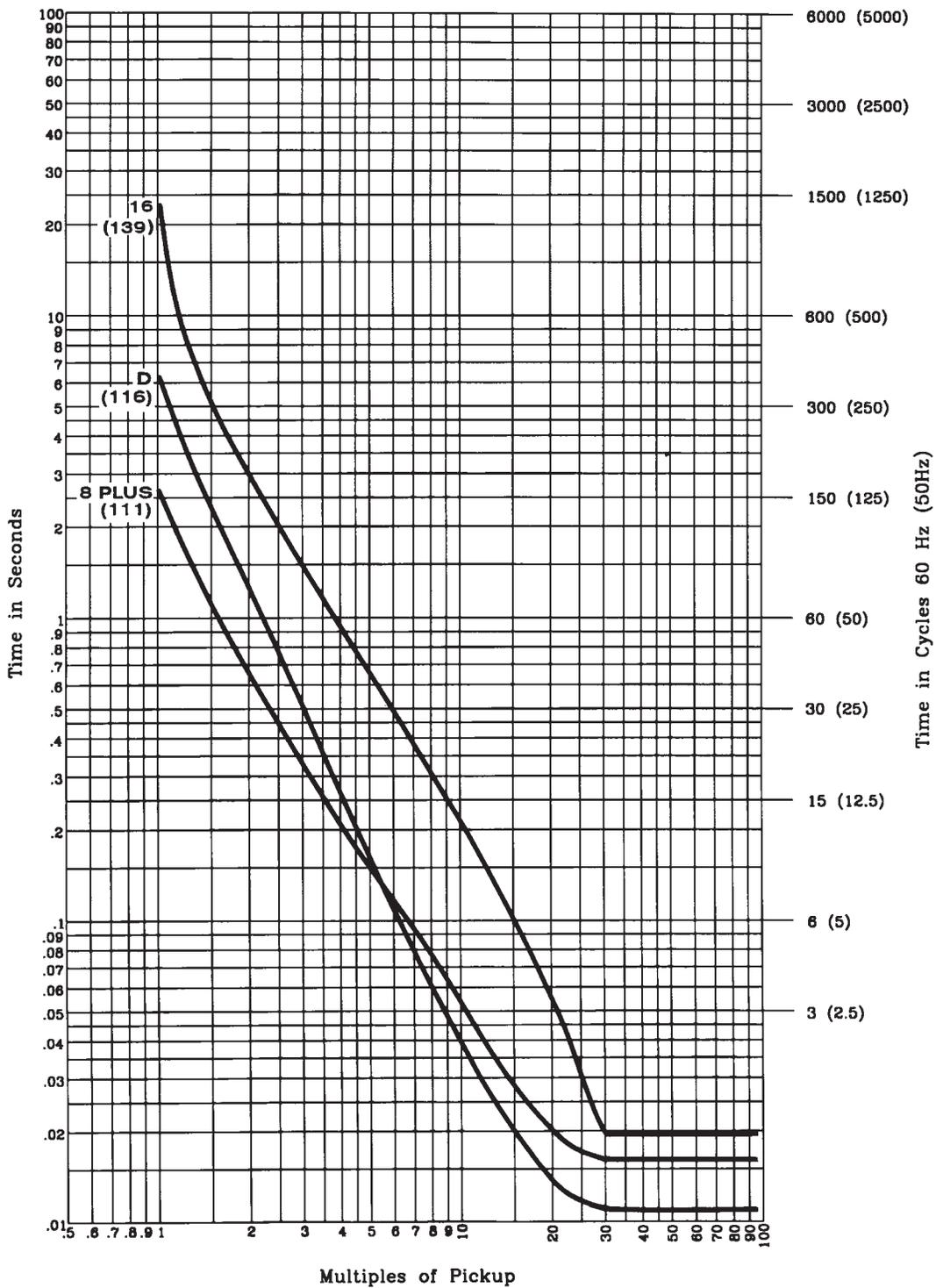
RECLOSER CONTROL TIME OVERCURRENT CURVES

DWG. NO. TOC1007
DATE: 25 JUN 98
RECLOSER CURVE 3
DECADE SCALE 2.213

Figure 9.13   Recloser Control Response Curves D, 8PLUS, and 16

9.20 Settings
Time-Overcurrent Curves

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RECLOSER CONTROL TIME OVERCURRENT CURVES
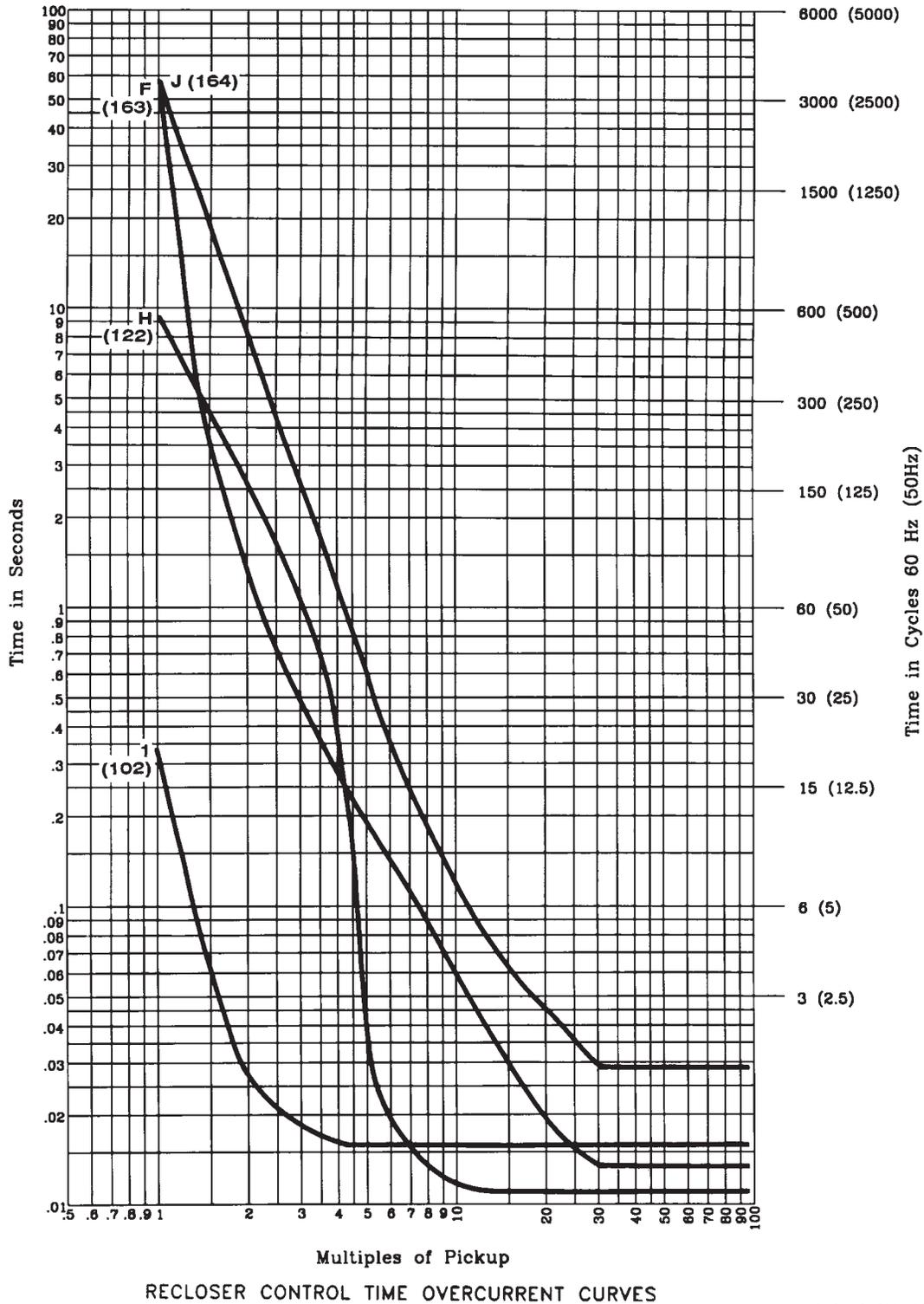
DWG. NO. TOC1008
DATE: 25 JUN 98
RECLOSER CURVE 4
DECADE SCALE 2.213

Figure 9.14   Recloser Control Response Curves F, H, J, and 1

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Settings 9.21
Time-Overcurrent Curves
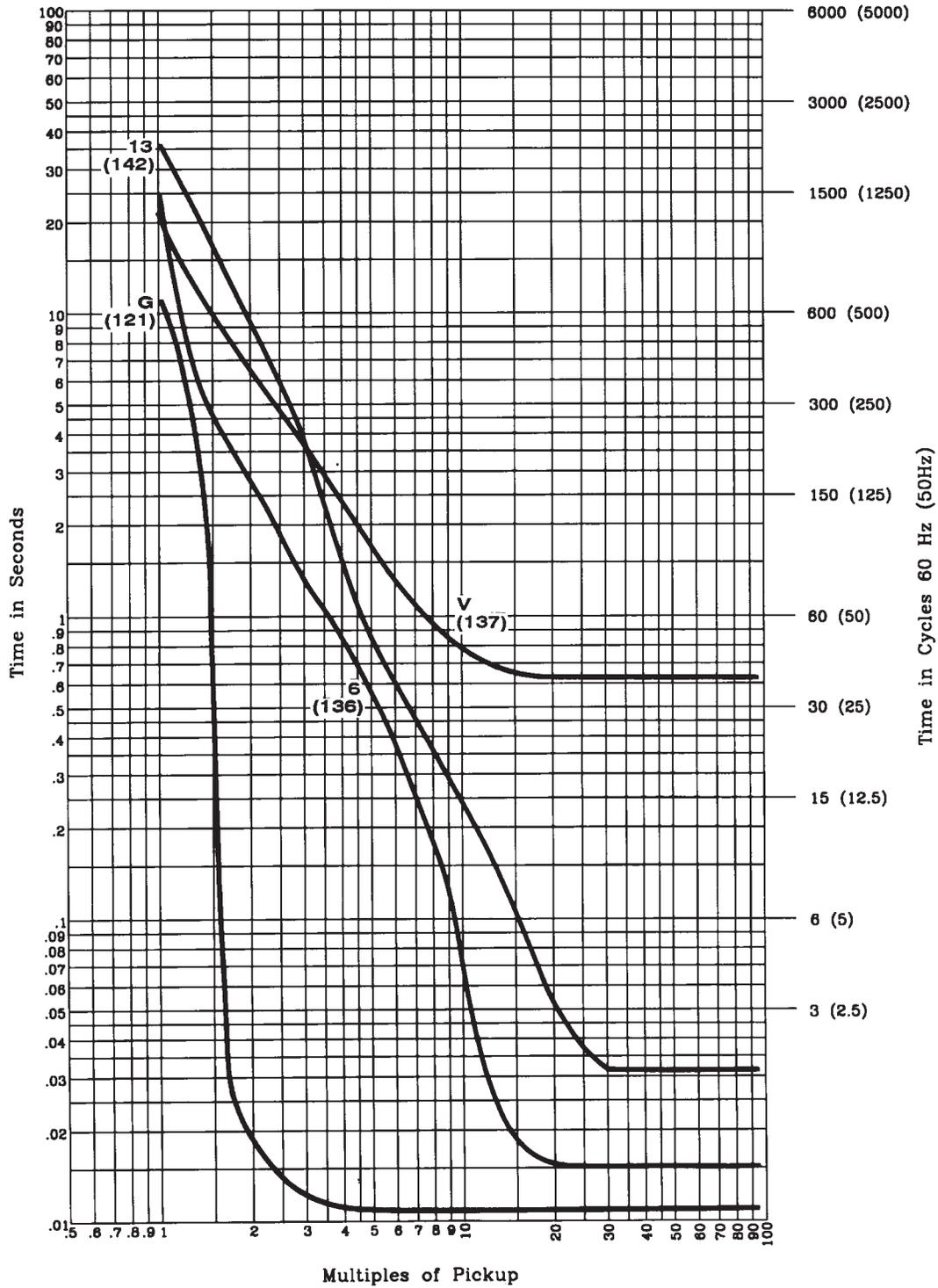
Figure 9.15   Recloser Control Response Curves G, V, 6, and 13

DWG. NO. TOC1009
DATE: 25 JUN 98
RECLOSER CURVE 5
DECADE SCALE 2.213

9.22 | Settings
Time-Overcurrent Curves

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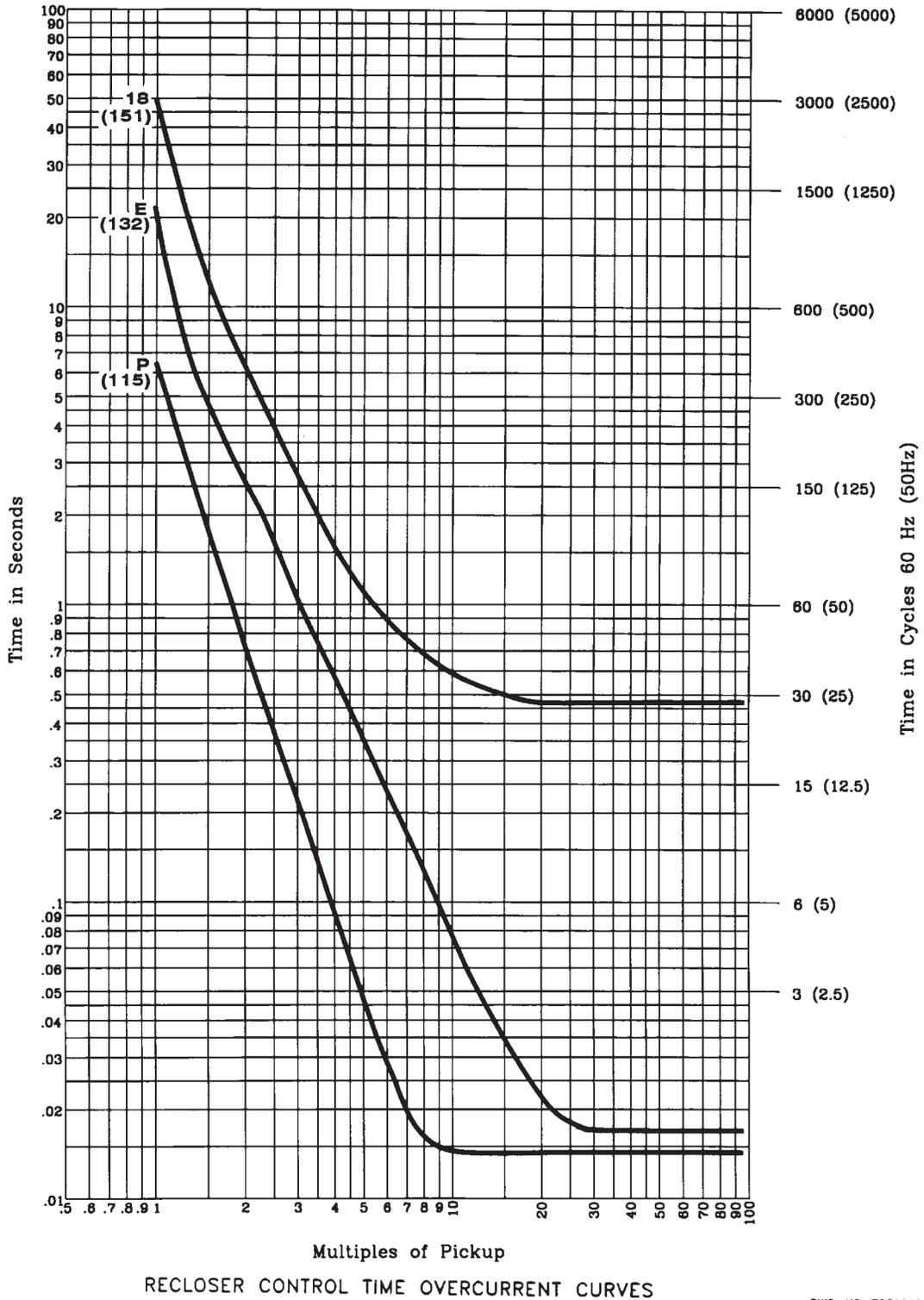
Figure 9.16   Recloser Control Response Curves E, P, and 18

9.23
Settings
Time Overcurrent Curves
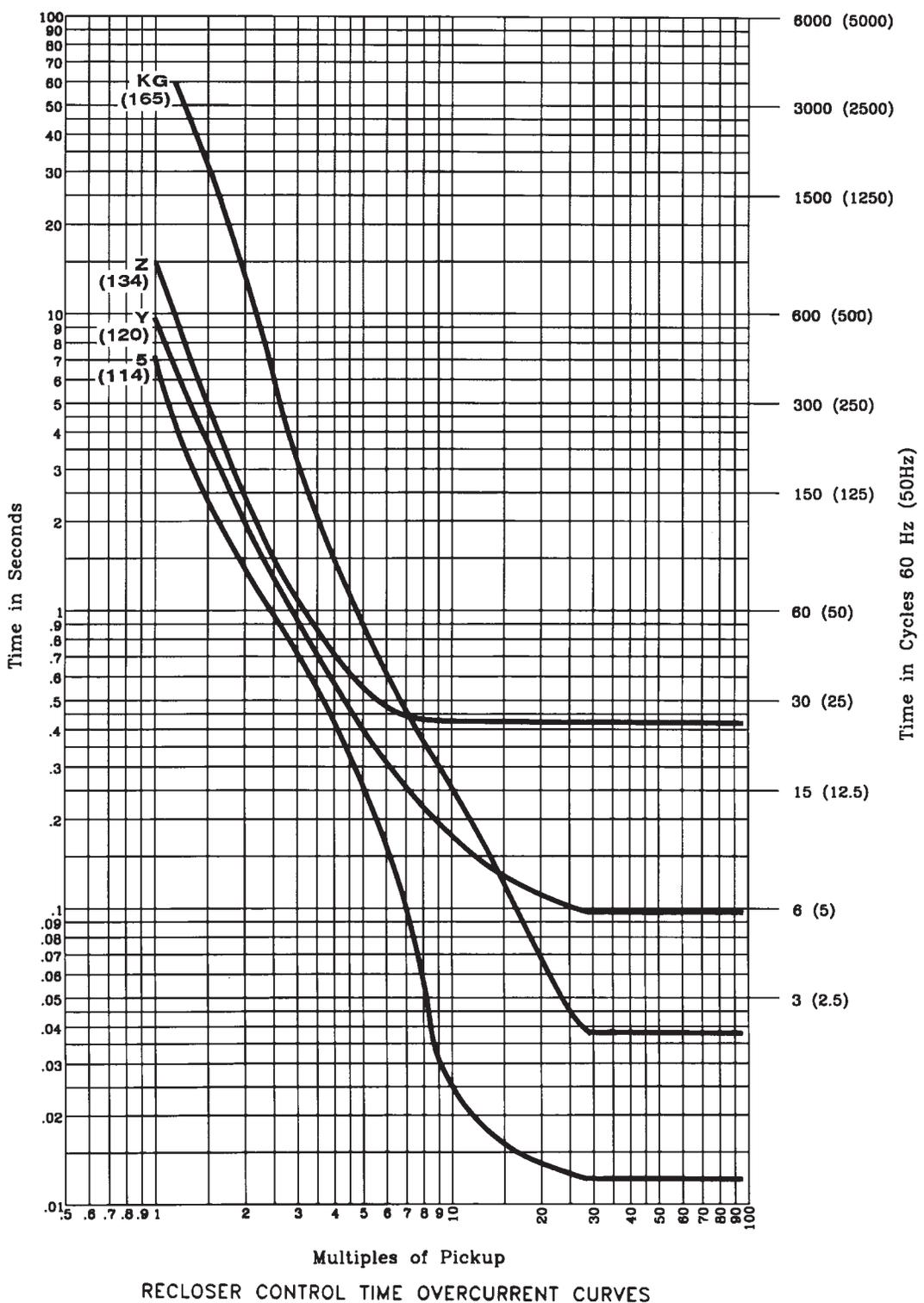
Figure 9.17   Recloser Control Response Curves KG, Y, Z, and 5

9.24 Settings
Time-Overcurrent Curves

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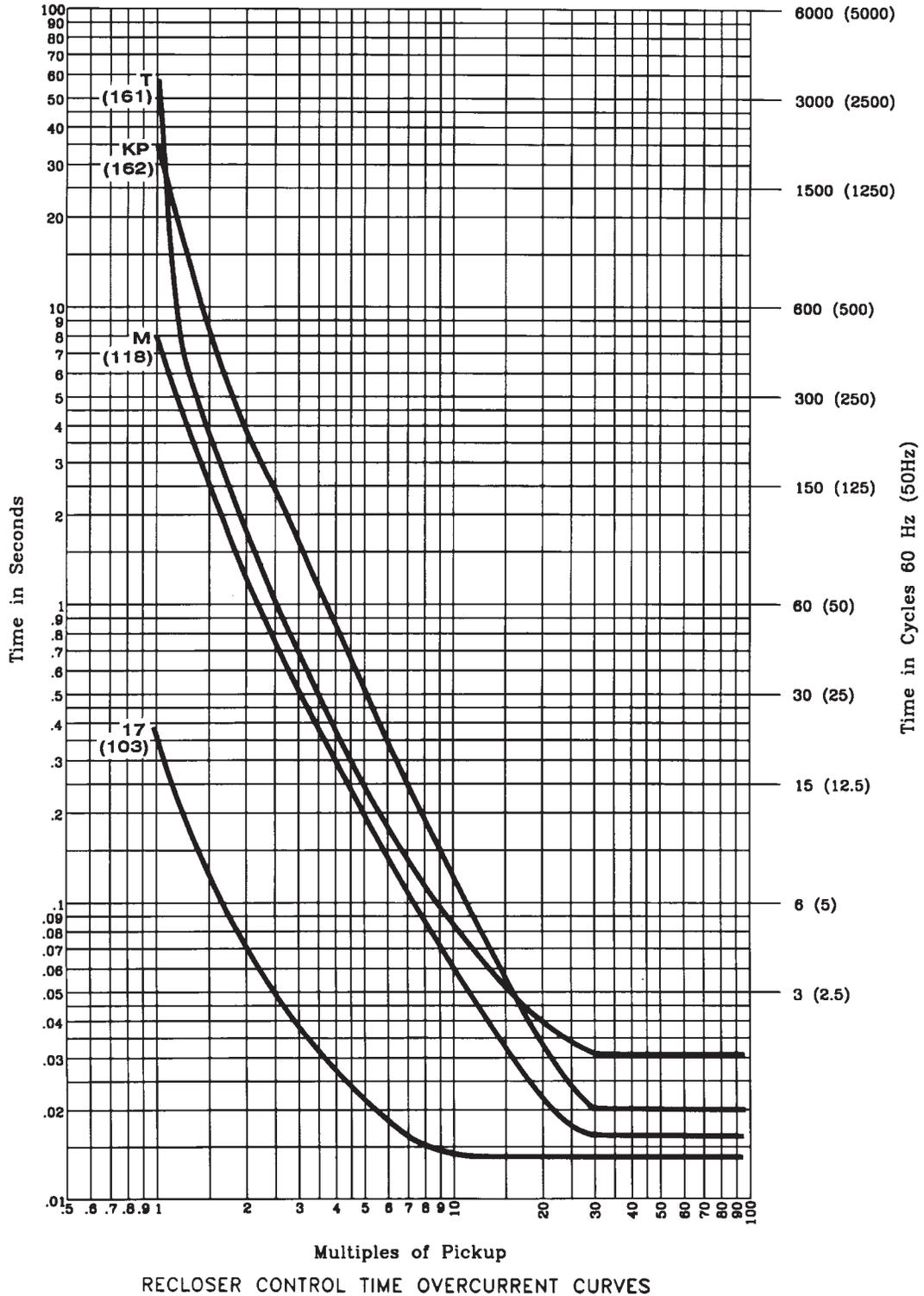
Figure 9.18   Recloser Control Response Curves KP, M, T, and 17

RECLOSER CONTROL TIME OVERCURRENT CURVES
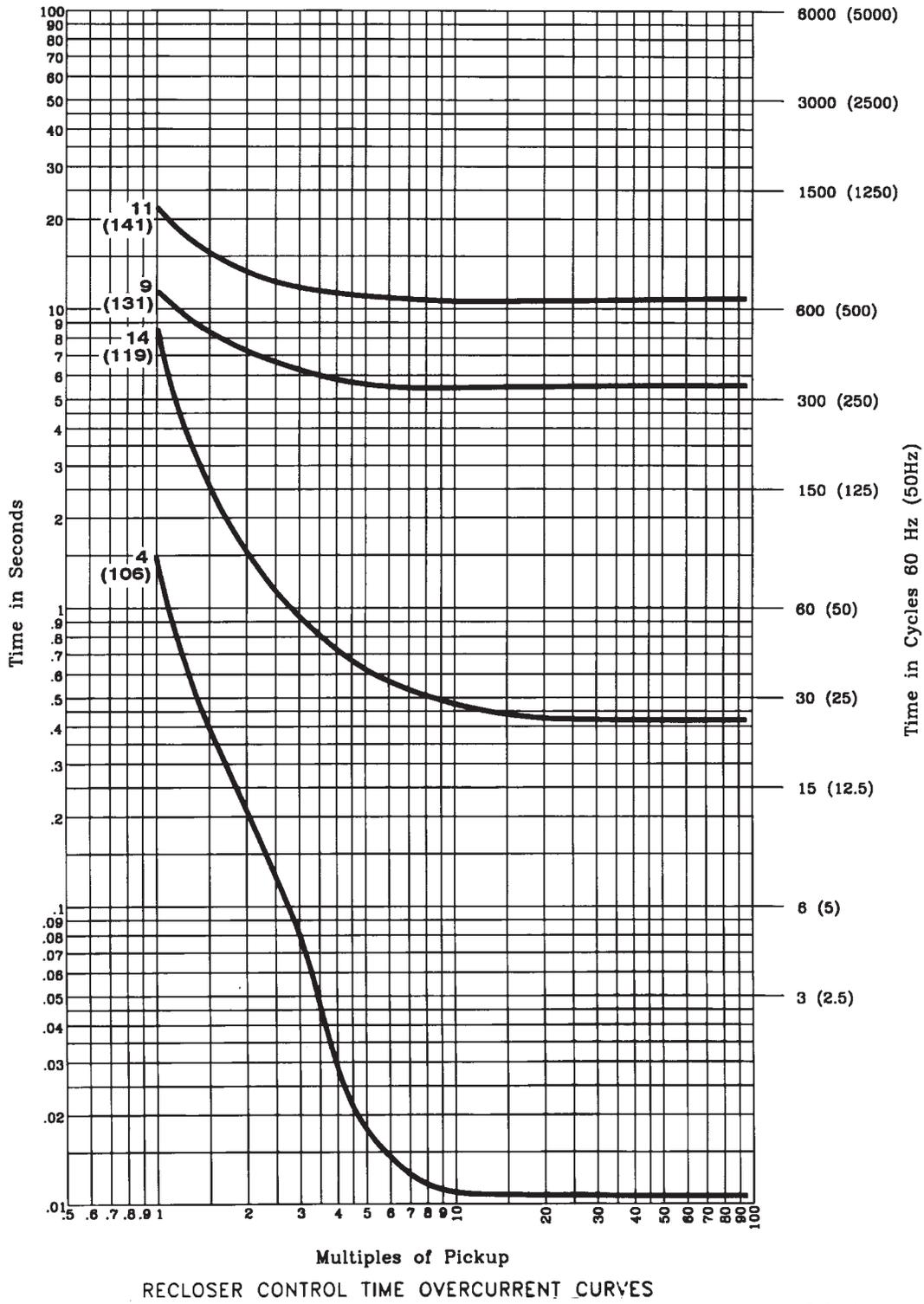
DWG. NO. TOC1013
DATE: 25 JUN 98
RECLOSER CURVE 9
DECADE SCALE 2.213

Figure 9.19   Recloser Control Response Curves 4, 9, 11, and 14

9.26 | Settings
Time-Overcurrent Curves

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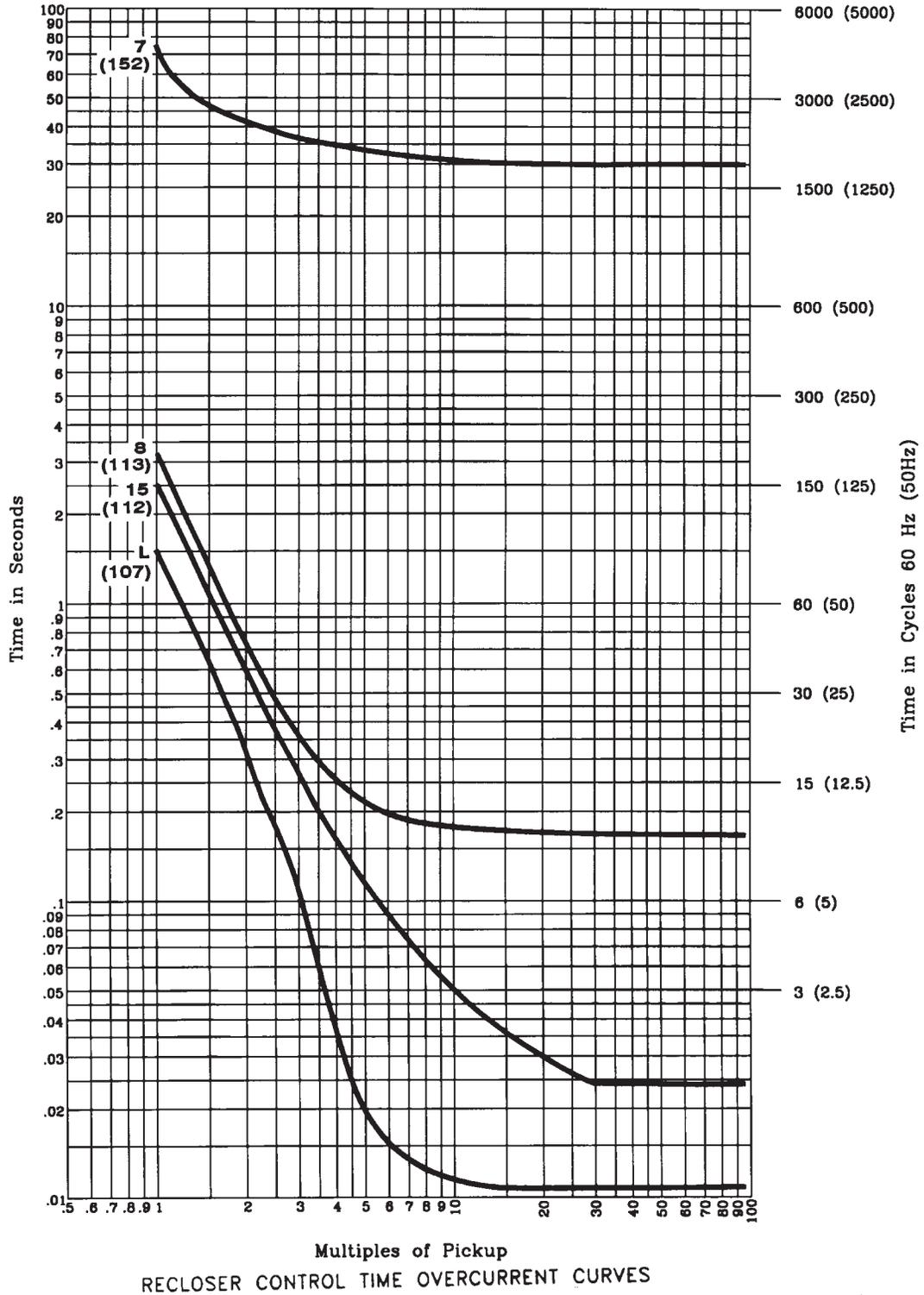
DWG. NO. TOC1014
DATE: 25 JUN 98
RECLOSER CURVE 10
DECADE SCALE 2.213

Figure 9.20   Recloser Control Response Curves L, 7, 8, and 15

SELOGIC Control Equation Settings

SELOGIC control equations appear in the Global, Group, Logic, and Front-Panel settings classes of the SEL-651R-2. This is different than the SEL-351R Recloser Control, which contains all of the SELOGIC control equation settings in one settings class.

The SEL-651R-2 offers enhanced SELOGIC control equation setting capabilities such as nested parentheses, analog comparisons, and the NA setting. The SELOGIC control equation setting syntax is fully described in *Section 7: SELOGIC Control Equation Programming*.

Relay Word Bits

Relay Word bits can be used in SELOGIC control equation settings. Numerous SELOGIC control equation settings examples are given in *Section 4: Protection Functions* through *Section 7: SELOGIC Control Equation Programming*. With a few exceptions, SELOGIC control equation settings can also be set directly to 1 (logical 1), 0 (logical 0), or NA (not applicable).

See *Table F.1* and *Table F.2* for a listing and description of the SEL-651R-2 Relay Word bits.

NA Setting

From a logic standpoint, setting an SELOGIC control equation to NA acts similarly to setting the equation to 0 (logical 0). The difference between 0 and NA is that the 0 setting consumes a small amount of microprocessor time every processing interval, while the NA setting consumes no microprocessor time. Thus, several SELOGIC control equation settings have factory-default values of NA, which allows more microprocessor time for other functions.

For example, setting TMB1A := NA (Channel A, Transmit Bit 1) will result in Relay Word bit TMB1A being "permanently deasserted."

See *SELOGIC Control Equation Capacity on page 7.1* for more information.

Analog Comparisons

Analog Quantities on page 7.2 describes the use of Analog Quantities in SELOGIC control equations.

Settings Explanations

Note that most of the settings in the settings sheets that follow include references for additional information. The following explanations are for settings that do not have reference information anywhere else in the instruction manual.

General (Global Settings)

Refer to *General Settings on page SET.1*.

The Global settings NFREQ and PHROT allow you to configure the SEL-651R-2 to your specific system.

Set NFREQ equal to your nominal power system frequency, either 50 Hz or 60 Hz.

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NOTE: The PHROT setting describes the electrical rotation of the power system phases, as opposed to the IPCONN, VYCONN, and VZCONN settings, which describe the connections to the SEL-651R-2 current and voltage terminals.

Set PHROT equal to your power system phase rotation, either ABC or ACB.

Set DATE_F to format the date displayed in recloser control reports and the front-panel display. Set DATE_F to MDY to display dates in Month/Day/Year format; set DATE_F to YMD to display dates in Year/Month/Day format; set DATE_F to DMY to display dates in Day/Month/Year format.

Current and Voltage Connections (Global Settings)

Refer to *Current and Voltage Connection Settings on page SET.1.*

The SEL-651R-2 connection terminals are shown in *Figure 2.3* and *Figure 2.5* for dual-door enclosure and *Figure 2.9* for single-door enclosure. The connection terminal markings are designated with numeric labels and terminal labels. For the purpose of explaining the current and voltage connection settings, a simplified list of the SEL-651R-2 current and voltage input terminals is used:

➤ For currents: **I1, I2, I3, IN**

➤ For voltages: **V1Y, V2Y, V3Y, V1Z, V2Z, V3Z**

This simplified list does not include the polarity marks on the current inputs. For example, the current channel I1 includes the physical terminals numbered Z01 (I1 polarity, indicated with a dot above the terminal) and Z02 (I1 nonpolarity), but will be referred to as only the I1 channel.

See *Figure 2.49–Figure 2.77* for current and voltage connections.

Current Connection Setting (IPCONN)

NOTE: The IPCONN setting serves a different function than the PHROT setting. See the note in General (Global Settings) on page 9.27.

NOTE: Other SEL-651R-2 settings handle the phase rolling of voltages, trip signals, close signals, and breaker status readings (see the following subsections).

The current signals are normally brought into the SEL-651R-2 cabinet via a prewired control cable. The factory-default connection includes a residual connection to the channel **IN** terminals and the **I1, I2,** and **I3** phase current terminals, as shown in *Figure 2.49–Figure 2.77.*

The electrical phase orientation of the power system overhead line is usually not easy to change, so the resulting CT secondary signals coming from the recloser are not the same in every installation. To eliminate the need to make wiring changes at the back panel, Global setting IPCONN can be used to designate which phases are connected to each of the terminals **I1, I2,** and **I3.** *Table 9.8* shows the required setting for IPCONN for the various CT signal connections.

MULTI-RECLOSER INTERFACE
The settings in Table 2.7, Table 9.15, Table 9.19, and Table 9.20 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93.

Table 9.8 Current Connection Setting IPCONN

Phase CT Signal Connections			Required Global Setting
I1 Terminals	I2 Terminals	I3 Terminals	IPCONN
I_A	I_B	I_C	ABC
I_A	I_C	I_B	ACB
I_B	I_A	I_C	BAC
I_B	I_C	I_A	BCA
I_C	I_A	I_B	CAB
I_C	I_B	I_A	CBA

Note that setting IPCONN is deemed a "reference setting" in *Table 9.15, Table 9.18, Table 9.19,* and *Table 9.20.* Subsection *Pole Status (52a), Trip, and Close Mapping Variations for Single-Phase Trip Capable Reclosers (Group Settings) on page 9.51* explains this in greater detail.

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Enable Ground Switch Setting (EGNDSW)

The SEL-651R-2 can operate with or without the **IN** channel connected to a current source. The factory-default wiring configuration employs a wired-residual connection to the **IN** terminals, allowing the measurement of zero-sequence current via the more sensitive **IN** channel. The effect of the EGNDSW setting is shown in *Table 9.16*, *Table 4.23*, and *Ground Switch Option on page 8.3*.

When setting EGNDSW is changed via the serial port **SET G** command, several functions in the Group settings class are disabled or changed.

The following warning is displayed when EGNDSW is changed from Y to N:

```
WARNING!  The global setting EGNDSW was changed to "N",
which will cause the E50G, E51G1, E51G2, 51G1JP,
51G1KP, E32, and GDEMP settings to be set to factory
default values in all settings groups.
```

The following warning is displayed when EGNDSW is changed from N to Y:

```
WARNING!  The global setting EGNDSW was changed to "Y",
which will cause E50N, E51N1, E51N2, NDEMP settings to
be set to OFF and CTRN setting to be set to the same
value as CTR in all settings groups.
```

Both warnings are followed by a confirmation prompt, which allows the technician to approve or cancel the changes.

CT Polarity Setting (CTPOL)

MULTI-RECLOSER INTERFACE
See Changing Global Setting RECL_CFG Changes the CTPOL Setting and the PTRY and PTRZ Settings for 8 Vac LEA Voltage Inputs on page 2.95.

The SEL-651R-2 uses directional information contained in current and voltage signals in these functions:

➤ Power measurement (see *Table 8.1*)

➤ Power elements

➤ Load encroachment

➤ Fault locator

➤ Directional control

The direction of the calculated power or impedance depends on the relative phase of the current measurements as compared to the voltage signals, which is normally a function of switchgear orientation. The CTPOL := (POS or NEG) setting provides an easy way to change the polarity of the measured current signals, and thus the resulting power direction and impedances.

Figure 2.49–Figure 2.77 show the SEL-651R-2 factory-default CT circuit wiring for supported reclosers. The directional arrows shown in the primary bus inside the switchgear identifies the forward or OUT direction, when Global setting CTPOL := POS.

The CTPOL setting functions by negating (or multiplying by –1) the current signals being read on the **I1**, **I2**, and **I3** current inputs (and the channel **IN** current if setting EGNDSW := Y) if setting CTPOL := NEG. The event report will show the polarity after the CTPOL adjustment is made, so any analysis tools, such as the ACSELERATOR Analytic Assistant SEL-5601 Software, will extract the same phase information that the SEL-651R-2 is using.

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Breaker/Recloser Type Setting (BKTYP) and Enable Single-Phase Breaker Setting (ESPB)

Global setting BKTYP indicates the type of recloser the SEL-651R-2 interfaces with:

➤ BKTYP := 3 (three-phase)—interface with recloser that is capable of only tripping and closing all three phases in unison

➤ BKTYP := 1 (single-phase)—interface with recloser that is capable of tripping and closing all three phases in unison or each phase individually

MULTI-RECLOSER INTERFACE
Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface on page 2.93.

Figure 6.2, *Figure 7.25*, and *Figure 7.26* use the BKTYP setting to set up the processing structure of breaker/pole status inputs and trip/close outputs. If BKTYP := 1, then Group setting ESPB (see *Figure 9.29*) can be set:

➤ ESPB := Y—enable single-phase tripping and closing

➤ ESPB := N—enable three-phase tripping and closing

Even with setting ESPB := Y, three-phase tripping can still occur (note Three-Phase Trip settings TRQL3P, TR3P, and TR3X in *Figure 5.1* are always enabled).

If BKTYP := 3, then ESPB := N always.

Figure 5.1 and *Figure 6.1* use the ESPB setting to set up the internal trip/close logic. *Figure 6.2* uses the ESPB setting to further refine breaker/pole status for single-phase or three-phase closing/reclosing.

Voltage Connection Settings (VYCONN and VZCONN)

The SEL-651R-2 has six analog voltage inputs, broken into two sets of three-phase connections, called the VY and VZ terminals. *Figure 2.41–Figure 2.46* cover the actual wiring for these inputs. This section deals with the settings that determine how the SEL-651R-2 processes the signals measured on these terminals.

The SEL-651R-2 can be used with all six voltage inputs connected; use of fewer than six voltage inputs results in reduced functionality.

Like the current inputs, the voltage input terminals are labeled numerically (1, 2, 3) instead of by phase letter (A, B, C). This allows settings to be used that assign the measured signal to the correct phase quantity inside the SEL-651R-2. This reassignment is sometimes called phase rolling. It is much easier to change a setting than to change wiring, so the settings VYCONN and VZCONN have been provided in the SEL-651R-2.

Voltage Terminal Designations (simplified):

➤ VY terminals: **V1Y, V2Y, V3Y**

➤ VZ terminals: **V1Z, V2Z, V3Z**

Unlike the CT connections shown in *Table 9.8*, it is possible to operate the recloser control with less than three voltages on a set of terminals. *Table 9.9* shows the six combinations of three-phase voltage connections on the VY terminals, plus six more single phase voltage connection variations.

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The VZ-terminal voltages have a similar choice of settings as *Table 9.9*, except a "VZ" is used instead of a "VY." Thus, the VZCONN setting is independent of the VYCONN setting.

Table 9.9 Voltage Connection Setting VYCONN and Affected Settings

VY-Terminal Signal Connections			Required Global Setting	"VY" Available as Setting Choice for:		
V1Y	V2Y	V3Y	VYCONN :=	EPHANT	VSELECT	FSELECT
V_A	V_B	V_C	ABC	no	yes	yes
V_A	V_C	V_B	ACB	no	yes	yes
V_B	V_A	V_C	BAC	no	yes	yes
V_B	V_C	V_A	BCA	no	yes	yes
V_C	V_A	V_B	CAB	no	yes	yes
V_C	V_B	V_A	CBA	no	yes	yes
V_A	–	–	A	yes	no	yes
V_B	–	–	B	yes	no	yes
V_C	–	–	C	yes	no	yes
V_{AB}	–	–	AB	yes	no	yes
V_{BC}	–	–	BC	yes	no	yes
V_{CA}	–	–	CA	yes	no	yes
-	–	–	OFF	no	no	no

Single-Phase and Phase-to-Phase Voltage Connections

The bottom half of *Table 9.9* lists single-phase and phase-to-phase connection options for voltage input V1Y. These voltage input V1Y connections are actually between terminals V1Y and NY (*Figure 2.5* for dual-door enclosure; see *Figure 2.9* for single-door enclosure). Even though terminal NY is the "neutral" connection, there is no internal ground connection on terminal NY, so phase-to-phase voltage connections can be made between voltage terminals V1Y and NY.

Figure 9.21 shows the voltage terminal assignments for these single-phase and phase-to-phase voltage connections. Even voltage terminals V2Y and V3Y are assigned, with the aid of the system rotation setting PHROT.

The internal voltages in *Figure 9.21* are used in the voltage elements (see *Voltage Elements on page 4.31*, *Figure 4.26*, and *Figure 4.27*) and in the event report columns (see *Figure 12.8*). Even though single-phase and phase-to-phase connections to V1Y and NY are shown in *Figure 9.21* (and "no connections" are shown at bottom of *Figure 9.21*), all the voltage terminals and subsequent internal voltages are active for the aforementioned voltage elements and event report columns.

Again, the VZ-terminal voltages have the same choices as the VY-terminal voltages portrayed in *Figure 9.21*—just substitute "VZ" for "VY". *Transition Between A-B-C Worlds on page 9.52* goes into greater detail and example on terminal assignments.

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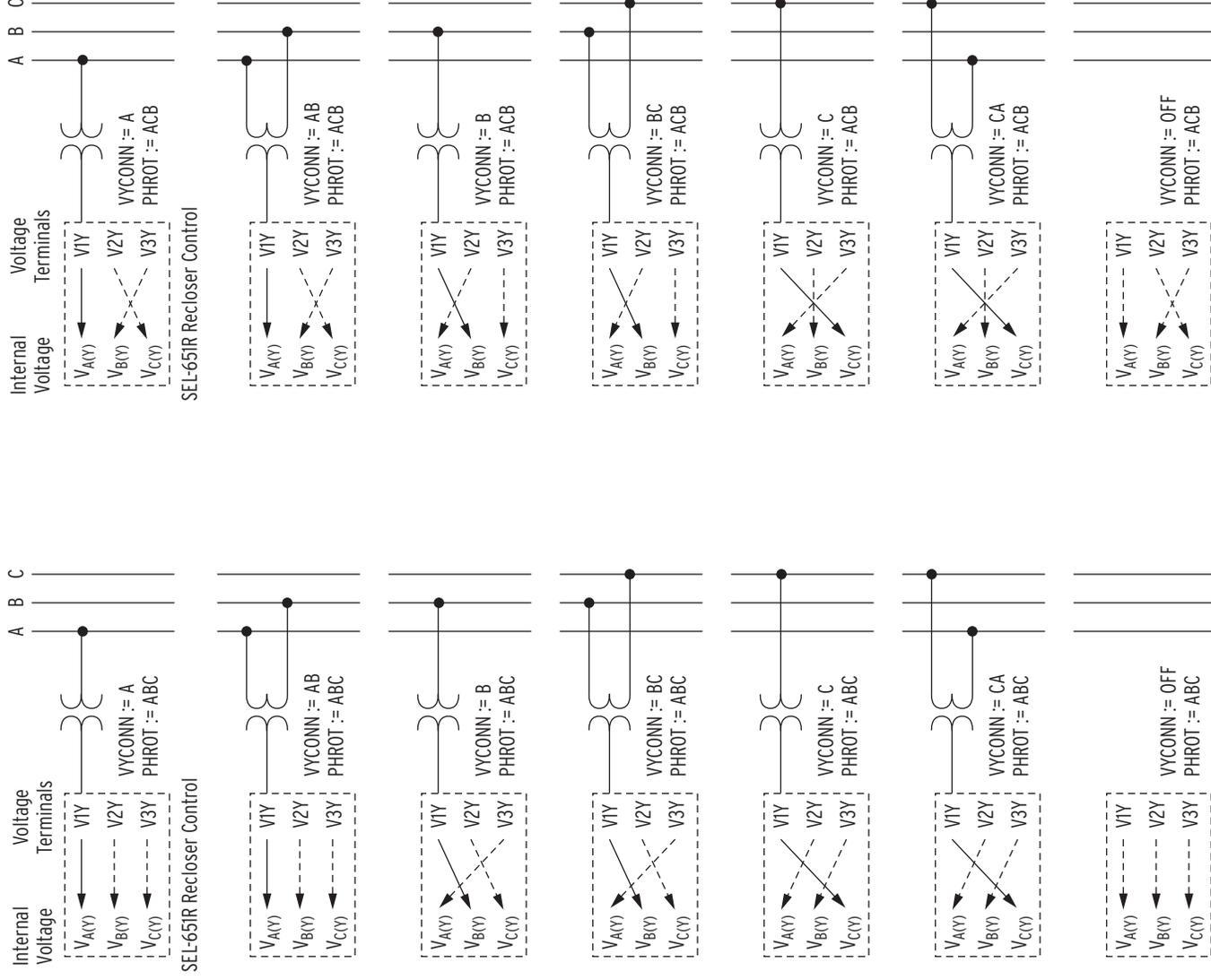
Figure 9.21   Terminal Assignments for Single-Phase and Phase-to-Phase Voltage Connections

Troubleshooting Voltage and Current Connections

The ability to make setting changes instead of wiring changes is very convenient. However, some tools are required to help troubleshoot problems that may arise if mistakes are made in either the wiring or the setting of the SEL-651R-2 current and voltage inputs.

The serial port **MET** command is a convenient troubleshooting tool to use because it is possible to quickly see how the SEL-651R-2 is interpreting the signals. *Section 10: Communications* contains a sample **MET** command capture. *Metering Check on page 2.36* gives a quick troubleshooting routine.

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Event Reports are also powerful diagnostic tools (see *Section 12: Analyzing Events*). Analytic Assistant allows graphical representation of compressed and COMTRADE event report data, including oscillography and phasor display.

QuickSet contains a phasor display function that operates directly from a serial port connection to the SEL-651R-2. It is found under the HMI menu.

Enable Phantom Voltage Setting (EPHANT)

The SEL-651R-2 can be configured to create phantom three-phase voltage signals from an applied single-phase voltage on either the VY terminals or the VZ terminals (but not both). *Table 9.9* shows the setting choices for VYCONN and VZCONN that allow the EPHANT setting to be made (see *Phantom Voltage Option Not in Service on page 8.6*).

The phantom voltage signals created are used only in fundamental metering functions (voltages, power, power factor, energy). The protection functions, including the under- and overvoltage elements, power elements, and event reports, are unaffected by the EPHANT setting.

Voltage Source Selection Setting (VSELECT)

The VSELECT setting is used to select which voltage terminals are used for the protection functions that require three-phase voltage:

- ➤ Power elements
- ➤ Load encroachment
- ➤ Fault locator
- ➤ Voltage Sag/Swell/Interruption elements
- ➤ Loss-of-potential
- ➤ Directional control

VSELECT also defines the voltage signals used in the power and energy metering functions, unless phantom voltages are selected (setting EPHANT ≠ OFF).

If VSELECT is changed to OFF, the following message is displayed.

```
WARNING!  The global setting VSELECT was changed to
"OFF". Settings ELOAD, E32, EFLOC, ELOP, EPWR, and ESSI
will be set to "N" in all settings groups.
```

The voltage elements are not affected by the VSELECT setting (see *Voltage Elements on page 4.31*).

The Relay Word bits VSELY and VSELZ are controlled by the VSELECT setting (see *Figure 9.29*).

Frequency Source Selection Setting (FSELECT)

The FSELECT setting is used to select which voltage terminals are used for the frequency tracking and frequency measurement functions:

- ➤ Frequency elements, including undervoltage block (see *Frequency Elements on page 4.50*)
- ➤ Synchronism-check elements (defines **VP** terminal; see *Synchronism-Check Elements on page 4.38*)

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For FSELECT := VY or OFF, the relay defaults to using the voltage connected to V1Y for frequency tracking. If a disturbance causes V1Y voltage to drop below 10 V for more than 60 cycles, the relay will attempt to use V2Y for frequency tracking. If V2Y is also less than 10 V, the relay will attempt to use V3Y. Operation of the relay with V1Z, V2Z, and V3Z is similar if FSELECT := VZ.

If FSELECT is changed to OFF, the following message is displayed.

```
WARNING!  The global setting FSELECT was changed to
"OFF". Settings E81, E81R and E25 will be set to "N" in
all settings groups.
```

Frequency measurement for synchronism-check elements uses a zero-crossing detector on the corresponding voltage terminal used for frequency tracking.

Frequency tracking will default to the **V1Y**, **V2Y**, or **V3Y** terminal when FSELECT := OFF.

Enable Independent Control Input Settings (Global Settings)

For most applications, leave setting EICIS := N. This selection causes the debounce timers for the recloser status inputs (IN201–IN206, *Figure 7.17*) and optional optoisolated inputs (IN101–IN107, *Figure 7.18*) to be hidden from view and set to factory-default values. If different debounce time settings are required, then set EICIS := Y and make the appropriate debounce timer settings.

Voltage Ratio Correction Factors for VY- and VZ-Terminal Voltage Inputs (Global Settings)

Make the V1YRCF, V2YRCF, and V3YRCF ratio correction factor Global settings for the VY-terminal voltage inputs (V1Y, V2Y, and V3Y, respectively) when they are ordered as low-energy analog (LEA) voltage inputs (see *Figure 9.22*, *Figure 9.23*, and *Figure 9.25*). Make the V1ZRCF, V2ZRCF, and V3ZRCF ratio correction factor Global settings for VZ-terminal voltage inputs (V1Z, V2Z, and V3Z respectively) when they are ordered as LEA voltage inputs (see *Figure 9.22*, *Figure 9.24*, and *Figure 9.25*). Ratio correction factor (RCF) settings compensate for irregularities (on a per-phase basis) of voltage dividers connected between the primary voltage system and the LEA inputs. The derivation of the RCF value for a voltage divider for a particular phase is defined as follows:

NOTE: Ratio Correction Factors serve a different purpose than Potential Transformer Ratio settings– see also following subsection Potential Transformer (PT) Ratios (Group Settings) on page 9.42.

$$RCF = \frac{\text{true ratio}}{\text{marked ratio}}$$

$$= \frac{(\text{Vpri.}/\text{Vsec.})}{\text{PTR}_{LEA}}$$

$$= \frac{\text{Vpri.}}{\text{Vsec.} \cdot \text{PTR}_{LEA}}$$

Equation 9.1

where:

Vpri. = test voltage applied to the primary side of the voltage divider

Vsec. = resultant voltage measured on the secondary side of the voltage divider

true ratio = Vpri./Vsec.

marked ratio = PTR_{LEA}

= effective nominal potential transformer (PT) ratio of the voltage divider connected between the primary voltage system and the LEA input (e.g., PTR_{LEA} = 10000 for G&W Viper-ST and G&W Viper-LT).

The marked ratio of the voltage divider (PTR_{LEA}) is always provided by the manufacturer and often the per-phase RCF values are also provided.

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If the voltage divider is perfect, then:

$$\frac{Vpri.}{Vsec.} = PTR_{LEA} \text{ and } RCF = 1.000$$

Equation 9.2

Thus, the measured voltage divider performance equals the marked ratio of the voltage divider, as given by the manufacturer. But such perfect conditions are usually not the case.

If the voltage divider is putting out more voltage (Vsec.) than nominally expected for an applied voltage input (Vpri.), then:

$$\frac{Vpri.}{Vsec.} < PTR_{LEA} \text{ and } RCF < 1.000$$

Equation 9.3

An example of an RCF value less than 1.000 is found in *Example 9.1*. In this example, setting V2YRCF := 0.883 brings down the too high voltage on voltage input V2Y (0.82 V is brought down to nominal 0.72 V).

If the voltage divider is putting out less voltage (Vsec.) than nominally expected for an applied voltage input (Vpri.), then:

$$\frac{Vpri.}{Vsec.} > PTR_{LEA} \text{ and } RCF > 1.000$$

Equation 9.4

An example of an RCF value greater than 1.000 is also found in following *Example 9.1*. In this example, setting V3YRCF := 1.112 brings up the too low voltage on voltage input V3Y (0.65 V is brought up to nominal 0.72 V).

In the SEL-651R-2 with LEA voltage inputs, RCF values for VY terminals (settings V1YRCF, V2YRCF, and V2YRCF) are applied to respective voltage inputs V1Y, V2Y, and V3Y, and the RCF values for VZ terminals (settings V1ZRCF, V2ZRCF, and V2ZRCF) are applied to respective voltage inputs V1Z, V2Z, and V3Z. The resultant secondary voltages from these voltage inputs are normalized by the RCF values. These normalized secondary voltages are used throughout the SEL-651R-2.

NOTE: At the end of the following subsection Voltage-Related Settings and LEA Inputs (Group Settings) on page 9.47 is a discussion concerning RCF values that are less than unity (1.000) and their possible effect on voltage-related settings.

EXAMPLE 9.1   Normalizing Voltages With Ratio Correction Factors

A voltage divider is connected to the 8 Vac LEA voltage inputs (see Figure 9.22). The RCF values per phase for the voltage divider are given as:

V1YRCF := 1.078 (voltage input V1Y; like Equation 9.4)
V2YRCF := 0.883 (voltage input V2Y; like Equation 9.3)
V3YRCF := 1.112 (voltage input V3Y; like Equation 9.4)

The marked ratio of the voltage divider is given as:

$$PTR_{LEA} = 10000$$

What are the true ratios of each phase of the voltage divider?

$$\text{true ratio (for a given phase)} = \frac{Vpri.}{Vsec.}$$

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Vpri. and Vsec. are measured in manufacturer tests, to derive RCF values as shown in Equation 9.1 and accompanying explanation. From Equation 9.1:

$$RCF \cdot PTR_{LEA} = \frac{Vpri.}{Vsec.} = \text{true ratio}$$

1.078 · 10000 = 10780 (true ratio for voltage input V1Y)
0.883 · 10000 = 8830 (true ratio for voltage input V2Y)
1.112 · 10000 = 11120 (true ratio for voltage input V3Y)

Note these true ratios vary from 8830 to 11120, while the marked ratio of the voltage divider is given as 10000.

Consider what is happening in this example. First, assume the primary voltage (Vpri.) is the same magnitude for each phase. When this primary voltage is run through the respective true ratios, the secondary voltage outputs vary widely. Presuming primary voltage of 12.47 kV (7.2 kV line-to-neutral), the resultant secondary voltages are listed below:

7200 V/10780 = 0.67 V
(true secondary voltage to voltage input V1Y)
7200 V/8830 = 0.82 V
(true secondary voltage to voltage input V2Y)
7200 V/11120 = 0.65 V
(true secondary voltage to voltage input V3Y)

Note that the true secondary voltages to voltage inputs V1Y and V3Y are running low (below normalized secondary voltage 0.72 V = 7200 V/10000), while the voltage to voltage input V2Y is running high (above normalized secondary voltage 0.72 V). But, the RCF values adjust these true secondary voltages to normalized secondary voltage:

0.67 V · 1.078 = 0.72 V
(normalized voltage from voltage input V1Y)
0.82 V · 0.883 = 0.72 V
(normalized voltage from voltage input V2Y)
0.65 V · 1.112 = 0.72 V
(normalized voltage from voltage input V3Y)

Again, the normalized secondary voltage (0.72 V) is the same for all three phases in this example, because the primary voltage is assumed the same magnitude for each phase (7200 V). These normalized secondary voltages are used throughout the SEL-651R-2. The true secondary voltages cannot be seen (via the SEL-651R-2), unless the RCF values are set to unity (RCF = 1.000).

Voltage Phase Angle Correction Settings for VY- and VZ-Terminal Voltage Inputs (Global Settings)

Make the V1YPAC, V2YPAC, and V3YPAC voltage phase angle correction Global settings for the VY-terminal voltage inputs (V1Y, V2Y, and V3Y, respectively) when they are ordered as low-energy analog (LEA) voltage inputs (see *Figure 9.23* and *Figure 9.25*). Make the V1ZPAC, V2ZPAC, and V3ZPAC voltage phase angle correction Global settings for the VZ-terminal voltage inputs (V1Z, V2Z, and V3Z, respectively) when they are ordered as LEA voltage inputs (see *Figure 9.24* and *Figure 9.25*). These settings compensate for the lagging phase shift caused by the voltage divider and the shielded cable bringing the voltages to the SEL-651R-2.

Refer to *Table 9.10–Table 9.14* to make voltage phase angle correction settings.

For example, if the SEL-651R-2 is used to control a NOVA TS-27 with a 30-foot, 26-pin control cable and a 20-foot, 14-pin junction box cable, then calculate the phase angle correction setting from *Table 9.11* as follows.

$$V1YPAC = V2YPAC = V3YPAC = -3.3° + -0.8°\left(\frac{(30-10)\text{ ft}}{10\text{ ft}}\right) + -1.4°\left(\frac{(20-10)\text{ ft}}{10\text{ ft}}\right) = -6.3°$$

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Table 9.10   Voltage Phase Angle Correction Settings for Eaton NOVA Three-Phase Reclosers

Model	Global Settings V1YPAC–V3YPAC for Various Control Cable Lengths				
	3.05 m (10 ft)	6.10 m (20 ft)	9.15 m (30 ft)	12.2 m (40 ft)	15.25 m (50 ft)
NOVA15	–1.9°	–3.0°	–4.1°	–5.2°	–6.3°
NOVA27 (and NOVA15 with extended BIL)	–3.4°	–4.5°	–5.6°	–6.7°	–7.8°
NOVA38 (and NOVA27 with extended BIL)	–5.7°	–6.8°	–7.9°	–9.0°	–10.0°

Table 9.11   Voltage Phase Angle Correction Settings for Eaton NOVA-TS Triple-Single Reclosers

Model	Global Settings V1YPAC–V3YPAC for 3.05 m (10 ft) 26-Pin Control Cable and 3.05 m (10 ft) 14-Pin Junction Box Cable
NOVA-TS-15	–2.1°[a]
NOVA-TS-27	–3.3°[b]
NOVA-TS-38	–5.5°[c]

[a] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.7°.
   For each additional 3.05 m (10 ft) of junction box cable, add a correction of –1.4°.
[b] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.8°.
   For each additional 3.05 m (10 ft) of junction box cable, add a correction of –1.4°.
[c] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.5°.
   For each additional 3.05 m (10 ft) of junction box cable, add a correction of –0.8°.

Table 9.12   Voltage Phase Angle Correction Settings for Eaton NOVA-STS Single-Tank, Triple-Single Reclosers

Model	Global Settings V1YPAC–V3YPAC for 3.05 m (10 ft) 26-Pin Control Cable
NOVA-STS-15	–0.8°[a]
NOVA-STS-27	–2.0°[b]
NOVA-STS-38	–4.2°[c]

[a] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.7°.
[b] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.8°.
[c] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.5°.

Table 9.13   Voltage Phase Angle Correction Settings for Eaton NOVA NX-T

Model	Global Settings V1YPAC–V3YPAC (Source Side) for 3.05 m (10 ft)	Global Settings V1ZPAC–V3ZPAC (Load Side) for 3.05 m (10 ft)[a]
15.5 kV	–2.88°	–2.94°
15.5 kV Extra Creep	–3.91°	–2.94°
27 kV	–5.62°	–2.66°
27 kV Extra Creep	–7.16°	–2.66°
38 kV	–7.16°	–2.66°

[a] For each additional 3.05 m (10 ft) of control cable, add a correction of –0.75°.

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Table 9.14   Voltage Phase Angle Correction Settings for Siemens SDR Reclosers

Model	Global Settings V1ZPAC–V3ZPAC for Various Control Cable Lengths				
	3.05 m (10 ft)	**6.10 m (20 ft)**	**9.15 m (30 ft)**	**12.2 m (40 ft)**	**15.25 m (50 ft)**
Siemens SDR Triple-Single	–1.4°	–2.1°	–2.7°	–3.3°	–4.0°
Siemens SDR Three-Phase	–1.4°	–2.1°	–2.7°	–3.3°	–4.0°

Because the phase shift can vary depending on the type and length of shielded cable used for the application, phase angle correction settings for Lindsey SVMI can be made by using the phase angle values on the opposite voltage terminals as a reference (if available). For example, consider a system where the VY-terminal inputs are 300 Vac PTs and the VZ-terminal inputs are Lindsey SVMI LEAs, connected to either side of the same recloser. The VY-terminal inputs can be used as the phase angle reference to determine the phase angle correction necessary for the Lindsey SVMI LEAs.

Breaker Monitor Initiate Settings (Global Settings)

See *Breaker Monitor Initiate SELOGIC Equations on page SET.5*.

The function of the Breaker Monitor initiate settings is fully explained in *Section 8: Metering and Monitoring*. The recommended settings depend on Global setting BKTYP.

When BKTYP := 3, only make setting BKMON3P.

The factory-default setting is:

> BKMON3P := RCTR1X.

This setting should satisfy all regular recloser applications.

The RCTR1X Relay Word bit is the final trip output for three-phase reclosers (see *Figure 7.25*).

When BKTYP := 1, only make settings BKMONA, BKMONB, and BKMONC.

The factory-default settings are:

> BKMONA := RCTR1X
>
> BKMONB := RCTR2X
>
> BKMONC := RCTR3X

These settings may need to change, depending on setting IPCONN, as shown in *Table 9.15*. Subsection *Pole Status (52a), Trip, and Close Mapping Variations for Single-Phase Trip Capable Reclosers (Group Settings) on page 9.51* explains the use of setting IPCONN as a "reference setting" in greater detail.

MULTI-RECLOSER INTERFACE
Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface on page 2.93.

NOTE: The system phase rotation (and Global setting PHROT) have no impact on the recommended settings shown in Table 9.15.

MULTI-RECLOSER INTERFACE
The BKMONx setting values in Table 9.15 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93.

Table 9.15   Breaker Monitor Mapping Global Settings for Single-Phase Recloser (BKTYP := 1) (Sheet 1 of 2)

Reference Global Setting	Recommended Global Settings		
IPCONN :=	BKMONA :=	BKMONB :=	BKMONC :=
ABC	RCTR1X	RCTR2X	RCTR3X
ACB	RCTR1X	RCTR3X	RCTR2X

Table 9.15 Breaker Monitor Mapping Global Settings for Single-Phase Recloser (BKTYP := 1) (Sheet 2 of 2)

Reference Global Setting	Recommended Global Settings		
BAC	RCTR2X	RCTR1X	RCTR3X
BCA	RCTR3X	RCTR1X	RCTR2X
CAB	RCTR2X	RCTR3X	RCTR1X
CBA	RCTR3X	RCTR2X	RCTR1X

Time and Date Management Settings (Global Settings)

The SEL-651R-2 supports several methods of updating the relay date and time.

For IRIG-B and Phasor Measurement Unit (PMU) synchrophasor applications, refer to *Configuring High-Accuracy Timekeeping on page J.21*.

For Simple Network Time Protocol (SNTP) applications, refer to *Simple Network Time Protocol (SNTP) on page 10.15*.

For time update from a DNP3 Master, see *Time Synchronization on page E.8*.

Coordinated Universal Time (UTC) Offset Setting (Global Settings)

The SEL-651R-2 has a Global setting UTC_OFF, settable from –24.00 to +24.00 hours, in 0.25-hour increments.

The relay HTTP (web) server uses the UTC_OFF setting to calculate UTC time stamps in request headers.

The relay also uses the UTC_OFF setting to calculate local (relay) time from the UTC source when configured for Simple Network Time Protocol (SNTP) updating via Ethernet. When a time source other than SNTP is updating the relay time, the UTC_OFF setting is not considered because the other time sources are defined as local time. When using IEEE C37.118-compliant IRIG-B signals (e.g., Global setting IRIGC = C37.118), the relay uses the UTC-to-local time offset provided as part of the time message to determine the local time. If the IRIG signal is lost, Global setting UTC_OFF is used.

Set UTC_OFF properly even if you expect some other time source, such as IRIG-B, to correct for the offset. If the time source fails, the relay will revert to SNTP or internal time and UTC_OFF will allow the relay to record and report the correct local time. If UTC_OFF is not set properly, some relay reports may show unexpected results.

Automatic Daylight-Saving Time Settings (Global Settings)

The SEL-651R-2 can automatically switch to and from daylight-saving time, as specified by the eight Global settings DST_BEGM–DST_ENDH. The first four settings control the month, week, day, and time that daylight-saving time shall commence, while the last four settings control the month, week, day, and time that daylight-saving time shall cease.

Once configured, the SEL-651R-2 will change to and from daylight-saving time every year at the specified time. Relay Word bit DST asserts when daylight-saving time is active.

The SEL-651R-2 interprets the week number settings DST_BEGW and DST_ENDW (1–3, L = Last) as follows:

➤ The first seven days of the month are considered to be in week 1.

➤ The second seven days of the month are considered to be in week 2.

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➤ The third seven days of the month are considered to be in week 3.

➤ The last seven days of the month are considered to be in week "L".

This method of counting of the weeks allows easy programming of statements like "the first Sunday", "the second Saturday", or "the last Tuesday" of a month.

As an example, consider the following settings:

DST_BEGM = **3**

DST_BEGW = **L**

DST_BEGD = **SUN**

DST_BEGH = **2**

DST_ENDM = **10**

DST_ENDW = **3**

DST_ENDD = **WED**

DST_ENDH = **3**

With these example settings, the relay will enter daylight-saving time on the last Sunday in March at 0200 h and leave daylight-saving time on the third Wednesday in October at 0300 h. The relay asserts Relay Word bit DST when daylight-saving time is active.

When an IRIG-B time source is being used, the relay time follows the IRIG-B time, including daylight-saving time start and end, as commanded by the time source. If there is a discrepancy between the daylight-saving time settings and the received IRIG-B signal, the relay follows the IRIG-B signal.

When using IEEE C37.118 compliant IRIG-B signals (e.g., Global setting IRIGC = C37.118), the relay automatically populates the DST Relay Word bit, regardless of the daylight-saving time settings.

When using regular IRIG-B signals (e.g., Global setting IRIGC = NONE), the relay only populates the DST Relay Word bit if the daylight-saving time settings are properly configured.

Set daylight-saving time beginning and ending properly even if you expect some other time source, such as IRIG-B, to correct for daylight-saving time. The relay relies on these settings for correct time should the time source fail (for IRIGC = C37.118) and to calculate UTC time correctly (when IRIGC = NONE). If daylight-saving time settings are not correct, some relay reports may show unexpected results. Use the **TIME DST** command to confirm the daylight-saving time settings and status (see *TIM Command (View/Change Time) on page 10.78*).

Identifier Labels (Group Settings)

Refer to *Identifier Labels on page SET.7*.

The SEL-651R-2 has two identifier labels: the Relay Identifier (RID) and the Terminal Identifier (TID). The Relay Identifier is typically used to identify the recloser control or the type of protection scheme. Typical Terminal Identifiers include an abbreviation of the substation name and line terminal.

The SEL-651R-2 tags each report (event report, meter report, etc.) with the Relay Identifier and Terminal Identifier. This allows you to distinguish the report as one generated for a specific breaker and substation.

RID and TID settings may include the following characters: 0–9, A–Z, -, /, ., space.

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Current Transformer (CT) Ratios (Group Settings)

Refer to *Current and Potential Transformer Ratios on page SET.7.*

Phase and neutral current transformer ratios are set independently. If neutral channel IN is connected residually with Terminals I1, I2, I3 (this matches the SEL-651R-2 factory-default wiring) then set CTR and CTRN the same. Group settings CTR and CTRN are used in SEL-651R-2 event reports and metering functions to scale secondary current quantities into primary values.

When channel IN is connected residually, make Global setting EGNDSW := Y. For ground protection (e.g., elements 50G1–50G6, 51G1, and 51G2), the channel IN signal will automatically be used for small signals and the calculated zero-sequence current (from terminals I1, I2, I3) will be used for large signals (see *Ground Switch Logic on page 4.76)*. Metering functions will follow a similar behavior for the IG-derived quantities (see *Ground Switch Option on page 8.3*).

For applications that require a high sensitivity to zero-sequence current, neutral channel IN is connected separately to a core-balance current transformer that encompasses the three phases. This type of current transformer typically has a lower ratio than the phase current transformers, which allows for more sensitivity in ground fault detection.

Make Global setting EGNDSW := Y for this application. Settings CTR and CTRN will be different in this case, with CTR being greater than CTRN. The setting limit for the ratio is:

$$1 \leq \frac{CTR}{CTRN} \leq 500$$

Equation 9.5

If channel IN is not connected, or it is connected to an unrelated current source (which is not measuring the zero-sequence current on the same electrical location as the phase CTs connected to terminals I1, I2, and I3), then make Global setting EGNDSW := N and set CTRN independently of CTR. Separate channel IN overcurrent elements, 50N1T–50N6T, 51N1T, and 51N2T, controlled by Enable settings E50N, E51N1, and E51N2, are available when EGNDSW := N.

Table 9.16 summarizes the above information.

Table 9.16   CTR and CTRN Settings in Relation to EGNDSW Setting

IN Channel Connection	EGNDSW Setting	CTRN Setting Requirements	50N Element Availability
Wired residually with terminals I1, I2, I3[a]	Y[a]	CTRN = CTR[a]	No[a]
Wired to a core-balance CT, measuring zero-sequence current on same line as CTs on terminals I1, I2, I3	Y	$1 \leq \frac{CTR}{CTRN} \leq 500$	No
Wired to a CT, unrelated to phase CTs	N	CTRN set independent of CTR	Yes
Not connected	N	CTRN setting not used	NA

[a] This is the factory-default configuration.

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CT Sizing

The SEL-651R-2 is designed to work with switchgear-mounted CTs. If the SEL-651R-2 is being installed in a substation application where CTs can be individually specified, see the guidelines in the technical paper *The Impact of High Fault Current and CT Rating Limits on Overcurrent Protection*, available at selinc.com.

Potential Transformer (PT) Ratios (Group Settings)

Refer to *Current and Potential Transformer Ratios on page SET.7*.

Group setting PTRY is the potential transformer ratio from the primary system to the SEL-651R-2 VY-terminal voltage inputs. Group setting PTRZ is the potential transformer ratio from the primary system to the SEL-651R-2 VZ-terminal voltage inputs. Setting these for traditional 300 Vac voltage inputs is straightforward.

For example, on a 12.47 kV phase-to-phase primary system with wye-connected 7200:120 V PTs, the correct PTRY or PTRZ setting is 7200/120 = 60.00.

PT Ratio Setting Adjustments

The SEL-651R-2 can be ordered with different secondary input voltage configurations (see *Models and Options on page 1.4*). Low-energy analog (LEA) voltage inputs are suitable for high-impedance sensors, such as capacitive voltage dividers and resistive voltage dividers. See the following subsections (with *Figure 9.22–Figure 9.25*) for information on how to derive PT ratio settings for various LEA voltage inputs.

Derive PT Ratio Settings for 8 Vac LEA Voltage Inputs (on G&W and Tavrida Reclosers)

MULTI-RECLOSER INTERFACE
See Changing Global Setting RECL_CFG Changes the CTPOL Setting and the PTRY and PTRZ Settings for 8 Vac LEA Voltage Inputs on page 2.95.

Refer to *Figure 9.22*.

Vpri. and Vsec. are in-phase—no phase angle correction needed. Cable capacitance is negligible ($C_2 \gg C_C$).

Vpri./Vsec. = true ratio of voltage divider when connected to the VY-terminal or VZ-terminal (8 Vac LEA) voltage inputs.

where:
Vpri./Vsec. = 10000 for G&W Electric Viper-ST and G&W Viper-LT reclosers
= 8793.75 for Tavrida OSM Al_2 and Tavrida OSM Al_4 recloser

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The SEL-651R-2 sees 8 Vac on the VY-terminal or VZ-terminal (8 Vac LEA) voltage inputs as 300 Vac. To realize accurate primary voltage metering, the corresponding potential transformer ratio settings (PTRY or PTRZ), are set as follows:

$$PTRY \text{ or } PTRZ = Vpri./Vsec. \cdot (8/300)$$

$$= \left(10000 \cdot \left(\frac{8}{300} \right) \right)$$

= 266.67 for G&W Electric Viper-ST and
    G&W Viper-LT reclosers

Equation 9.6

$$= \left(8793.75 \cdot \left(\frac{8}{300} \right) \right)$$

= 234.50 for Tavrida OSM Al_2 and
    Tavrida OSM Al_4

Equation 9.7
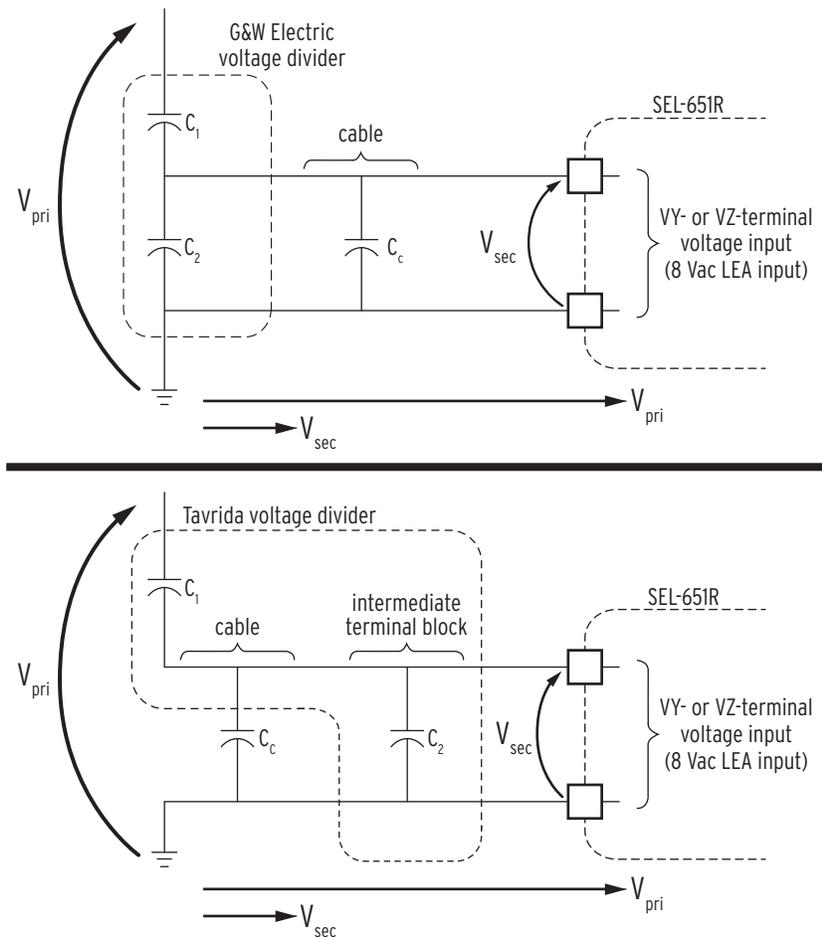
Figure 9.22 Voltage Divider Connections and Relative Voltage Phase Angles for 8 Vac LEA Voltage Inputs (for G&W Electric Viper-ST, G&W Viper-LT, Tavrida OSM Al_2, and Tavrida OSM Al_4 Reclosers)

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Derive PT Ratio Settings for 8 Vac LEA Voltage Inputs
(on ABB OVR/Gridshield and OVR-3/VR-3S)

Vpri./Vsec. = true ratio of voltage divider when connected to the VY-terminal or VZ-terminal (8 Vac LEA) voltage inputs.

where:

Vpri./Vsec. = 10000 for ABB OVR/Gridshield (32-pin and 42-pin), and ABB OVR-3/VR-3S (24-pin) reclosers

MULTI-RECLOSER INTERFACE
See Changing Global Setting RECL_CFG Changes the CTPOL Setting and the PTRY and PTRZ Settings for 8 Vac LEA Voltage Inputs on page 2.95.

The SEL-651R-2 sees 8 Vac on the VY-terminal or VZ-terminal (8 Vac LEA) voltage inputs as 300 Vac. To realize accurate primary voltage metering, the corresponding potential transformer ratio settings (PTRY or PTRZ), are set as follows:

$$\text{PTRY or PTRZ} = \text{Vpri./Vsec.} \cdot (8/300)$$

$$= \left(10000 \cdot \left(\frac{8}{300}\right)\right)$$

$$= 266.67 \text{ for ABB OVR/Gridshield (32-pin and 42-pin)}$$
$$\text{and ABB OVR-3/VR-3S (24-pin) reclosers}$$

Equation 9.8

Derive PT Ratio Settings for 8 Vac LEA Voltage Inputs
(on Eaton NOVA NX-T)

Vsec. lags Vpri. because of cable capacitance and the voltage divider being resistive—phase angle correction is needed (see *Table 9.13*).

Vpri./Vsec. = true ratio of voltage divider when connected to the VY-terminal or VZ-terminal (8 Vac LEA) voltage inputs.

where:

Vpri./Vsec. = 1476 for Eaton NOVA NX-T (15.5 kV models)
             = 2955 for Eaton NOVA NX-T (27 kV and 38 kV models)

MULTI-RECLOSER INTERFACE
See Changing Global Setting RECL_CFG Changes the CTPOL Setting and the PTRY and PTRZ Settings for 8 Vac LEA Voltage Inputs on page 2.95.

The SEL-651R-2 sees 8 Vac on the VY-terminal or VZ-terminal (8 Vac LEA) voltage inputs as 300 Vac. To realize accurate primary voltage metering, the corresponding potential transformer ratio settings (PTRY or PTRZ), are set as follows:

$$\text{PTRY or PTRZ} = \text{Vpri./Vsec.} \cdot (8/300)$$

$$= \left(1476 \cdot \left(\frac{8}{300}\right)\right)$$

$$= 39.36 \text{ for Eaton NOVA NX-T (15.5 kV models)}$$

Equation 9.9

$$= \left(2955 \cdot \left(\frac{8}{300}\right)\right)$$

$$= 78.8 \text{ for Eaton NOVA NX-T}$$
$$\text{(27 kV and 38 kV models)}$$

Equation 9.10

Derive PT Ratio Settings for Eaton NOVA LEA Voltage Inputs

NOTE: The Eaton NOVA NX-T recloser uses 8 V LEA inputs. See Derive PT Ratio Settings for 8 Vac LEA Voltage Inputs (on Eaton NOVA NX-T) for NOVA NX-T LEA PTR settings.

Refer to *Figure 9.23*.

Vsec. lags Vpri. because of the voltage divider resistance R1 and cable capacitance CC—phase angle correction is needed (see *Table 9.10– Table 9.12*).

Vpri./Vsec. = true ratio of voltage divider when connected to the VY-terminal (Eaton NOVA LEA) voltage inputs.

$$\text{Vpri./Vsec.} = 607 \text{ for Eaton NOVA 15 recloser}$$
$$= 1213 \text{ for Eaton NOVA 15*, NOVA 27,}$$
$$\text{NOVA 27*, and NOVA 38 reclosers}$$
$$\text{* with extended BIL}$$

The SEL-651R-2 sees 37.09 Vac on the VY-terminal (Eaton NOVA LEA) voltage inputs as 300 Vac. To realize accurate primary voltage metering, the corresponding potential transformer ratio setting (PTRY) is set as follows:

$$\text{PTRY} = \text{Vpri./Vsec.} \cdot (37.09/300)$$
$$= \left(607 \cdot \left(\frac{37.09}{300}\right)\right)$$
$$= 75.04 \text{ (round to 75.00) for Eaton NOVA 15 recloser}$$

Equation 9.11

$$= \left(1213 \cdot \left(\frac{37.09}{300}\right)\right)$$
$$= 149.96 \text{ (round to 150.00) for Eaton NOVA 15*,}$$
$$\text{NOVA 27, NOVA 27*, and NOVA 38 reclosers}$$
$$\text{*with extended BIL}$$

Equation 9.12
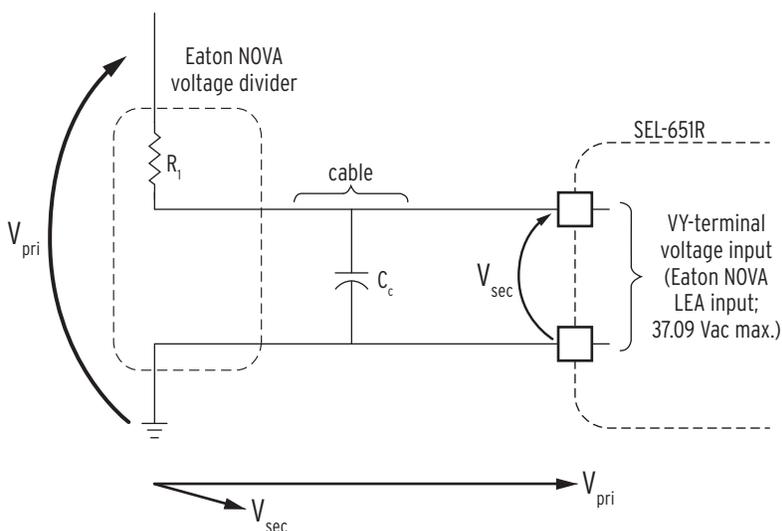
Figure 9.23   Voltage Divider Connections and Relative Voltage Phase Angles for Eaton NOVA LEA Voltage Inputs (for Eaton NOVA Reclosers)

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Derive PT Ratio Settings for Siemens LEA Voltage Inputs

Refer to *Figure 9.24*.

Vsec. lags Vpri. because of voltage divider resistance R1 and cable capacitance CC—phase angle correction is needed (see *Table 9.14*).

Vpri./Vsec. = true ratio of voltage divider when connected to the VZ-terminal (Siemens LEA) voltage inputs.

$$Vpri./Vsec. = 1281 \text{ for Siemens SDR 15.5 kV recloser}$$
$$= 2231 \text{ for Siemens SDR 27 kV recloser}$$

The SEL-651R-2 sees 8.49 Vac on the VZ-terminal (Siemens LEA) voltage inputs as 300 Vac. Thus, to realize accurate primary voltage metering, the corresponding potential transformer ratio setting (PTRZ) is set as follows:

$$PTRZ = Vpri./Vsec. \cdot (8.49/300)$$
$$= \left(1281 \cdot \left(\frac{8.49}{300} \right) \right)$$
$$= 36.25 \text{ for Siemens SDR 15.5 kV recloser} \quad \textbf{Equation 9.13}$$

$$= \left(2231 \cdot \left(\frac{8.49}{300} \right) \right)$$
$$= 63.14 \text{ for Siemens SDR 27 kV recloser} \quad \textbf{Equation 9.14}$$
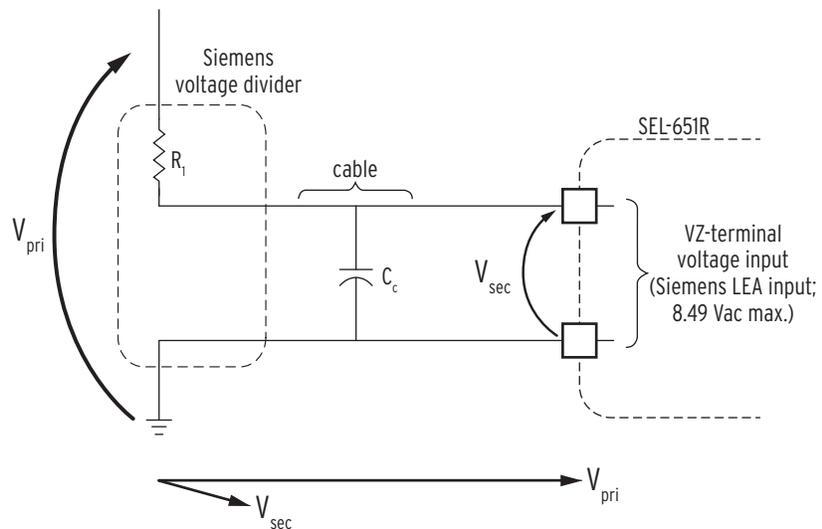
Figure 9.24   Voltage Divider Connections and Relative Voltage Phase Angles for Siemens LEA Voltage Inputs (for Siemens SDR Reclosers)

Derive PT Ratio Settings for 120 Vac, 1M Lindsey SVMI LEA Voltage Inputs

Refer to *Figure 9.25*.

Vsec. lags Vpri. because of voltage divider resistances R1 and R2 (R1 >> R2) and cable capacitance CC—phase angle correction is needed (see Lindsey SVMI discussion following *Table 9.14*).

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Vpri./Vsec. = true ratio of voltage divider when connected to the VY-terminal or VZ-terminal (120 Vac, 1M Lindsey SVMI LEA) voltage inputs.

The SEL-651R-2 sees the voltage applied on the VY-terminal or VZ-terminal (120 Vac, 1M Lindsey SVMI LEA) voltage inputs as exactly that voltage (e.g., 120 Vac applied appears as 120 Vac to the SEL-651R-2). The corresponding potential transformer ratio settings (PTRY or PTRZ) are set directly to the ratio of the Lindsey SVMI voltage sensor:

PTRY or PTRZ := Vpri./Vsec. **Equation 9.15**
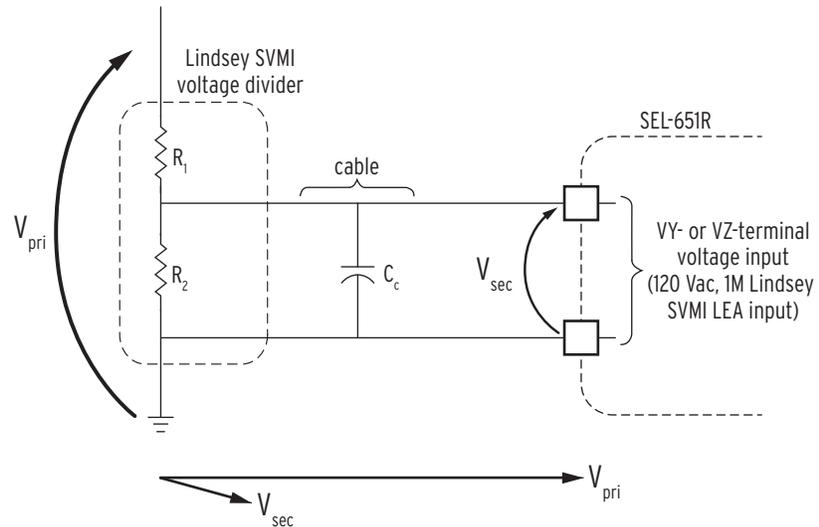
Figure 9.25   Voltage Divider Connections and Relative Voltage Phase Angles for 120 Vac, 1M Lindsey SVMI LEA Voltage Inputs

Voltage-Related Settings and LEA Inputs (Group Settings)

Study *Figure 9.22* in preparation for the following example.

When the voltage inputs are 8 Vac LEA inputs, any voltage-related setting tied to the voltage inputs (e.g., VY-terminal voltage inputs; see *Table 9.17*) is adjusted by a factor of 300/8.

EXAMPLE 9.2   Voltage Setting Conversion to 300 V Base

This example uses much of the same information in Figure 9.22. A voltage divider (10000 ratio) is connected between a 12.47 kV system (7.2 kV line-to-neutral) and the LEA inputs.

$$\frac{7200 \text{ V}}{10000} = 0.72 \text{ V}$$ (actual voltage divider output to the 8 Vac LEA inputs; 8 V base)

$$0.72 \text{ V} \cdot \frac{300}{8} = 27 \text{ V}$$ (the relay thinks it is looking at 27 V on a 300 V base, not 0.72 V on an 8 V base)

27 V is the nominal adjusted secondary voltage–adjusted by the 300/8 factor from an 8 V base to a 300 V base. For this same example, if a 0.8 V output of the 8 Vac LEA (8 V base) is deemed an overvoltage condition, then an overvoltage element pickup setting (e.g., 59YP1P) could be set at:

$$59\text{YP1P} := 0.8 \text{ V} \cdot \frac{300}{8} = 30 \text{ V}$$ (300 V base)

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This 300/8 adjustment factor also applies to power elements (see *Table 4.21* and accompanying text), if power element pickup settings (3PWR1P–3PWR4P) are initially computed using the actual voltage values connected to the 8 Vac LEA inputs.

Table 9.17   Adjust Voltage-Related Settings When the Voltage Inputs Are 8 Vac LEA Inputs (VY-Terminal Example)

Setting	Multiply 8 Vac Base Voltage Value by 300/8 Factor:	Setting Sheet
VNOM *(nominal voltage)*	When VSELECT := VY	*Page SET.7*
27YP1P, 27YP2P, 27YPP1P, 59YP1P, 59YP2P, 59YPP1P, 59YN1P, 59YN2P, 59YQ1P, 59YV1P *(for voltage elements)*	Always	*Page SET.25*
27B81P *(for blocking frequency elements)*	When FSELECT := VY	*Page SET.26*
3PWR1P, 3PWR2P, 3PWR3P, 3PWR4P *(for power elements)*	When VSELECT := VY	*Page SET.28*
25VPLO, 25VPHI	When FSELECT := VY	*Page SET.28*
25VSLO, 25VSHI *(for supervising synchronism-check elements)*	When FSELECT := VZ	

Table 9.17 is an example of modifying VY-terminal voltage-related settings for 8 Vac LEA inputs. Similar modifications can be made for VZ-terminal voltage-related settings for 8 Vac LEA inputs. Similar modifications can also be made for other LEA input types by applying like factors to the particular LEA base voltage value:

➤ Eaton NOVA LEA:

  multiply *37.09 Vac base* voltage value by 300/37.09 factor (see *Figure 9.23*)

➤ Siemens LEA:

  multiply *8.49 Vac base* voltage value by 300/8.49 factor (see *Figure 9.24*)

➤ 120 Vac, 1M Lindsey SVMI LEA:

  No adjustment needed (see *Figure 9.25*)

Voltage-Related Settings Possibly Limited by RCF Settings

Read the preceding subsection *Voltage Ratio Correction Factors for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.34*.

If most of the voltage range for VY-terminal voltage inputs (ordered as 8 Vac LEA voltage inputs) is used in a particular installation (i.e., the nominal applied secondary voltage is close to or equal to 8 V), then a ratio correction factor (RCF) set below unity (RCF < 1.000) can effectively limit the upper setting range of a voltage-related setting.

This subsection, together with *Example 9.2* and *Table 9.17*, discusses making voltage-related settings for LEA 8 V inputs by applying an adjustment factor of 300/8. This adjustment factor puts the setting on a 300 V base. Thus, an 8 V signal on an 8 Vac LEA voltage input translates to a 300 V signal on a base of 300 V, the upper setting range for the phase-to-neutral voltage-related settings.

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For example, if the RCF for voltage input V2Y is set to

Global setting V2YRCF $= 0.900$ $(< 1.000;$ set below unity)

and 8 V is applied to voltage input V2Y, then this applied voltage is normalized to

$8\text{ V} \cdot 0.900 = 7.2\text{ V}$ (normalized voltage from voltage input V2Y)

The upper limit for voltage that can be applied to the VY-terminal voltage inputs is 8 V. Assuming the 0.900 RCF in the previous equations is the lowest RCF for the VY-terminal voltage inputs and that the normalized voltages for all the voltage inputs should be the same (7.2 V in this example), then the maximum applied voltages for the other two channels (RCF's > 0.900) must be less than 8 V:

$$\frac{7.2\text{ V}}{\text{RCF}} < 8\text{ V} \qquad (\text{RCF} > 0.900)$$

The 7.2 V normalized voltage in this example translates to 270 V on a 300 V base:

$$7.2\text{ V} \cdot \frac{300}{8} = 270\text{ V} \quad (300\text{ V base})$$

The effective upper setting range is 270 V for the phase-to-neutral voltage-related settings in this example. A phase-to-neutral voltage-related setting can be set higher (e.g., 290 V), but for voltage input V2Y such a setting would be indistinguishable from a 270 V setting, in this example. The VY-terminal voltage inputs (ordered as 8 Vac LEA voltage inputs) cannot distinguish voltages above 8 V.

$$8\text{ V} \cdot 0.900 \cdot \frac{300}{8} = 270\text{ V} \quad (300\text{ V base})$$

Preceding *Example 9.2* is *not* an example of this possible effective limiting of the upper setting range of voltage-related settings. In *Example 9.2*, the nominal applied secondary voltage to the VY-terminal voltage inputs is 0.72 V, nowhere near the 8 V upper limit for VY-terminal voltage inputs (ordered as 8 Vac LEA voltage inputs).

Line Length (Group Setting)

Refer to *Line Parameter Settings on page SET.10*.

Line length setting LL is used in the fault locator function (see *Fault Location on page 12.8*). The line length is associated with the line impedance settings (described in next subsection).

Line length setting LL is unitless and corresponds to the line impedance settings. For example, if a particular line length is 15 miles, enter the line impedance values (Ω secondary) and then enter the corresponding line length:

LL = **15.00** (miles)

If this length of line is measured in kilometers rather than miles, then enter:

LL = **24.14** (kilometers)

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Line Impedance Conversions (Group Settings)

Refer to *Line Parameter Settings on page SET.10*, *Load-Encroachment Elements on page SET.24* and *Directional Elements on page SET.24*.

The SEL-651R-2 has eight settings that are in units of ohms, secondary (impedance). The settings are Z1MAG and Z0MAG (used in the Fault Locator), ZLF and ZLR (used in the Load-Encroachment logic), and Z2F, Z2R, Z0F, and Z0R (used in Directional Control).

Impedance values are converted from primary ohms to secondary ohms using either *Equation 9.16* or *Equation 9.17*.

When VSELECT := VY

$$\Omega \text{ primary} \bullet \left(\frac{\text{CTR}}{\text{PTRY}} \right) = \Omega \text{ secondary}$$

Equation 9.16

> **NOTE**: The derived Ω secondary values in Equation 9.16 and Equation 9.17 are on a 300 V base. This even holds true when the VY-terminal voltage inputs are LEA inputs, because the PTRY setting has already been adjusted to 300 V (see Equation 9.6–Equation 9.14). Lindsey SVMI LEA inputs need no adjustment (see Equation 9.15).

where:

CTR = phase (IA, IB, IC) current transformer ratio setting
PTRY = phase (V1Y, V2Y, V3Y) potential transformer ratio setting (see note)

When VSELECT := VZ

$$\Omega \text{ primary} \bullet \left(\frac{\text{CTR}}{\text{PTRZ}} \right) = \Omega \text{ secondary}$$

Equation 9.17

where:

CTR = phase (IA, IB, IC) current transformer ratio setting
PTRZ = phase (V1Z, V2Z, V3Z) potential transformer ratio setting

When VSELECT := OFF, the fault locator and load-encroachment logic will not be available and the associated settings cannot be accessed.

Math Variables (Group Settings)

Refer to *Math Variable Settings on page SET.34*.

The math variable settings in the SEL-651R-2 are controlled by enable setting EMV = 1–64. In the SEL-651R-2, these variables are numeric settings in the range –16000.00 to +16000.00. There are no units associated with the math variable settings. These settings create analog quantities (with the same name as the setting) that are available for use in analog comparisons in SELOGIC control equations (see *Table 7.2*).

> **NOTE**: The context of a math variable is completely defined by its application. In the SEL-651R-2, math variables are not mathematical expressions. They are numeric constants. The SEL-651R-2 does not offer mathematical operations in SELOGIC control equation expressions.

The math variable MV01 := 2.00 is the only one used in the SEL-651R-2 factory-default settings. This setting selects the number of phase and ground time-overcurrent element operations on the fast curve, by virtue of being included in the factory-default setting for 51PSW, 51G1SW, and 79SKP3P. This default logic is described in *Figure 6.12* and related example in *Section 6: Close and Reclose Logic*.

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Pole Status (52a), Trip, and Close Mapping Variations for Single-Phase Trip Capable Reclosers (Group Settings)

NOTE: If a single-phase trip capable recloser is ordered (Global setting BKTYP := 1), and the application does not require single-phase tripping and closing, make Group setting ESPB := N. The remainder of this subsection could be skipped, although it is recommended that these settings be followed if possible at commissioning time. If a single-phase trip scheme is specified in the future (ESPB := Y), then the recloser control is properly configured.

NOTE: The ABB OVR-3/VR-3S (24-pin, 15 and 27 kV models), and Tavrida OSM AI_2 reclosers use 52b style contacts. 52A_x equation should use the inverse of the inputs (NOT IN20x).

NOTE: The system phase rotation (and Global setting PHROT) has no impact on the recommended settings shown in Table 9.18, Table 9.19 and Table 9.20.

MULTI-RECLOSER INTERFACE
The settings in Table 2.7, Table 9.15, Table 9.19, and Table 9.20 are automatically set (and hidden), according to Global setting IPCONN, for the Multi-Recloser Interface on page 2.93. Also, Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface on page 2.93.

Refer to *Close Logic Settings on page SET.36* and *Recloser Interface Trip and Close Settings on page SET.37*. Review *Breaker Status Logic on page 6.3* and *Trip and Close Mapping and Output Logic on page 7.31*.

In *Figure 9.27* and *Figure 9.28*, notice that the control cables bring in current, pole status (52a), and trip/close signals together for each single phase. For example, in *Figure 9.28*, current I3, pole status 52a3, and Trip 3/Close 3 are all associated with B-phase:

$\quad$ IPCONN := CA**B** $\quad$ (current channel I**3** connected to **B**-phase)

$\quad$ 52A_**B** := IN20**3** $\quad$ (pole status 52a**3** connected to IN20**3**)

$\quad$ RCTR**3** := TRIP**B** OR ... $\quad$ (drives output RCTR**3**X, connected to Coil **3**)

$\quad$ RCCL**3** := CLOSE**B** OR ... $\quad$ (drives output RCCL**3**X, connected to Coil **3**)

Global setting IPCONN associates the current channels with the power system. For example, in *Figure 9.28*, IPCONN := CAB with current channels:

➤ I1 connected to C-phase

➤ I2 connected to A-phase

➤ I3 connected to B-phase

This same IPCONN Global setting information can be used to make similar breaker monitor, pole status (52a), trip, and close mapping settings, as shown in *Table 9.15*, *Table 9.18*, *Table 9.19*, and *Table 9.20*, respectively.

Table 9.18 Pole Status (52a) Mapping Group Settings for Single-Phase Trip Capable Reclosers (Global Setting BKTYP := 1)

Reference Global Setting	Recommended Pole Status (52a) Mapping Group Settings		
IPCONN :=	52A_A :=	52A_B :=	52A_C :=
ABC	IN201	IN202	IN203
ACB	IN201	IN203	IN202
BAC	IN202	IN201	IN203
BCA	IN203	IN201	IN202
CAB	IN202	IN203	IN201
CBA	IN203	IN202	IN201

Table 9.19 Trip Mapping Settings for Single-Phase Trip Capable Reclosers (Global Setting BKTYP := 1)

Reference Global Setting	Recommended Trip Mapping Group Settings		
IPCONN :=	RCTR1 :=	RCTR2 :=	RCTR3 :=
ABC	TRIPA OR TRIP3P	TRIPB OR TRIP3P	TRIPC OR TRIP3P
ACB	TRIPA OR TRIP3P	TRIPC OR TRIP3P	TRIPB OR TRIP3P
BAC	TRIPB OR TRIP3P	TRIPA OR TRIP3P	TRIPC OR TRIP3P
BCA	TRIPB OR TRIP3P	TRIPC OR TRIP3P	TRIPA OR TRIP3P
CAB	TRIPC OR TRIP3P	TRIPA OR TRIP3P	TRIPB OR TRIP3P
CBA	TRIPC OR TRIP3P	TRIPB OR TRIP3P	TRIPA OR TRIP3P

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Table 9.2O   Close Mapping Settings for Single-Phase Trip Capable Reclosers (Global Setting BKTYP := 1)

Reference Global Setting	Recommended Close Mapping Group Settings		
IPCONN :=	RCCL1 :=	RCCL2 :=	RCCL3 :=
ABC	CLOSEA OR CLOSE3P	CLOSEB OR CLOSE3P	CLOSEC OR CLOSE3P
ACB	CLOSEA OR CLOSE3P	CLOSEC OR CLOSE3P	CLOSEB OR CLOSE3P
BAC	CLOSEB OR CLOSE3P	CLOSEA OR CLOSE3P	CLOSEC OR CLOSE3P
BCA	CLOSEB OR CLOSE3P	CLOSEC OR CLOSE3P	CLOSEA OR CLOSE3P
CAB	CLOSEC OR CLOSE3P	CLOSEA OR CLOSE3P	CLOSEB OR CLOSE3P
CBA	CLOSEC OR CLOSE3P	CLOSEB OR CLOSE3P	CLOSEA OR CLOSE3P

It is important to test that pole status (52a) and trip/close signals for a particular phase correspond to the proper current channel, before placing the unit into service. If the mapping settings shown in *Table 9.18*, *Table 9.19*, and *Table 9.20* are set incorrectly, tripping and closing may misoperate. *Table 9.18*, *Table 9.19*, and *Table 9.20* presume that the wiring from the control cable to the SEL-651R-2 relay module is not changed (see the various trip/close and recloser pole status figures in *Section 2: Installation*).

The SEL-651R-2 issues the following warning message when the IPCONN Global setting is changed (when Global setting BKTYP := 1):

```
WARNING!  The IPCONN setting was changed. Recloser trip
(RCTR_), close (RCCL_), status (52A_), and breaker
monitor initiate (BKMON_) SELogic Equation settings may
also need to be changed.
```

MULTI-RECLOSER INTERFACE
This warning for an IPCONN Global setting change is not displayed for the Multi-Recloser Interface on page 2.93. Also, Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface on page 2.93.

Also, the SEL-651R-2 issues the following warning message when the BKTYP Global setting is changed:

```
WARNING!  The global setting BKTYP was changed.
Settings ESPB, SPOD, and 52A_ will be affected.
Settings related to trip, close, and reclose logic, and
the breaker status (52A_) and breaker monitor initiate
(BKMON_) settings may need to be changed.
```

Transition Between A-B-C Worlds

In *Figure 9.26*, the SEL-651R-2 "1-2-3" connections provide a transition between the:

"A-B-C" power system world, outside

and the

"A-B-C" algorithm world, inside the SEL-651R-2

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Figure 9.26   Overview of Transition Between A-B-C Worlds Inside and Outside the SEL-651R-2

Wiring to the power system (potential transformer connections and recloser primary bushing connections) can be rather random, but correct power system "A-B-C" designation is still needed within the SEL-651R-2 algorithms. Preceding *Table 9.8–Table 9.15*, *Figure 9.21*, and *Table 9.18–Table 9.20* list the settings and all the possible settings combinations that realize the correct "A-B-C" designations within the SEL-651R-2 for the numerous possible power system connections.

Figure 9.27 and *Figure 9.28* are a more in depth look at the transition idea given in *Figure 9.26*. The underlying assumption in *Figure 9.27* and *Figure 9.28* is that the wiring from the control cable is factory-standard in its connection to both the SEL-651R-2 Recloser Control and the recloser (i.e., there is no rearrangement of the factory-default cable wiring). Note that the currents, trip/close signals, and pole status (52a) come through the control cable, but the voltage connections are separate. Thus, for a given phase, the current, trip/close signal, and pole status (52a) remain grouped together.

Straight-Through Phase Connections

From inspection of the SEL-651R-2 settings and connections in *Figure 9.27*, the correspondence between the power system world and the SEL-651R-2 connections is:

$$A \longleftrightarrow 1$$
$$B \longleftrightarrow 2$$
$$C \longleftrightarrow 3$$

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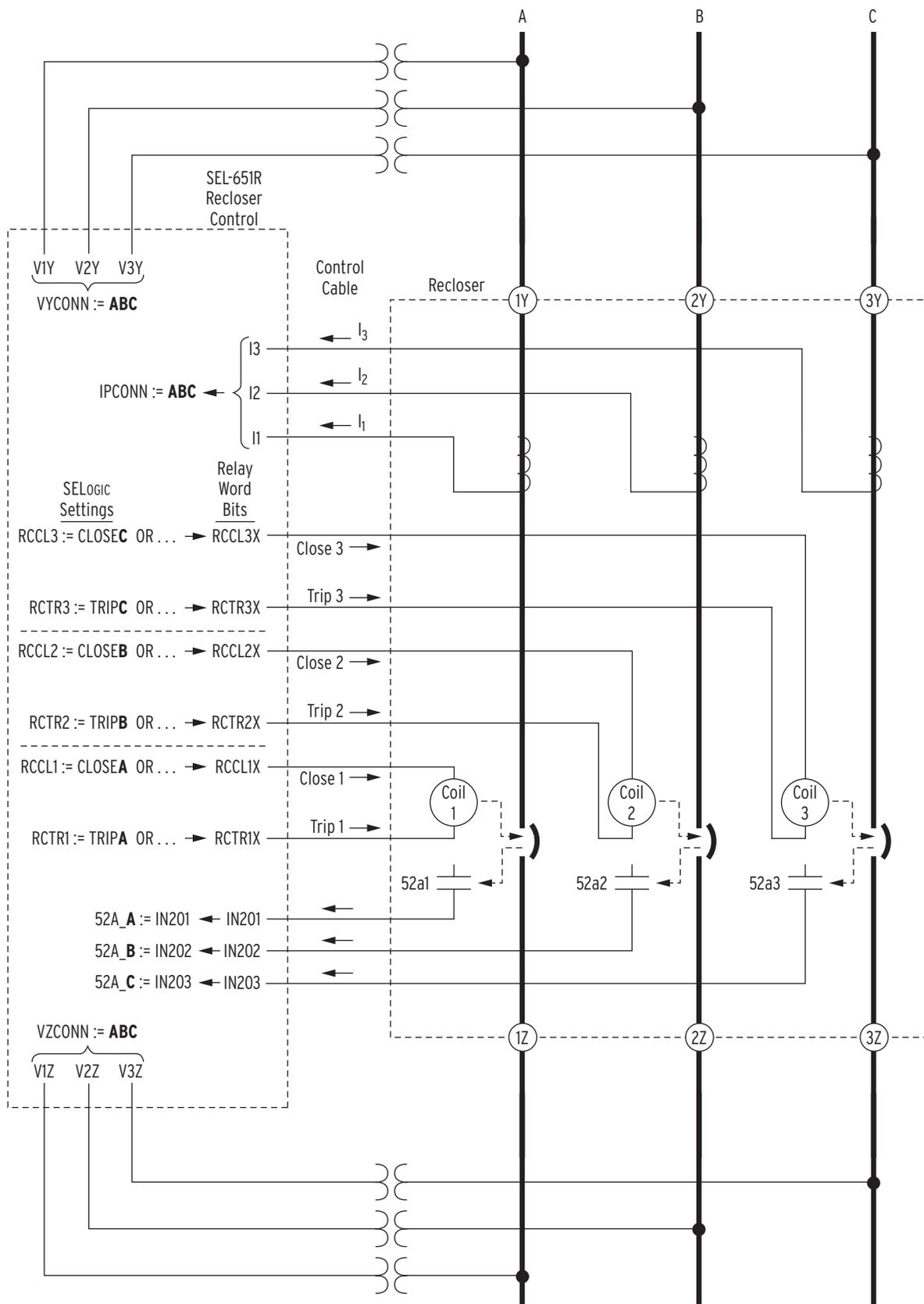
Figure 9.27 Single-Phase Trip Capable Recloser With Straight-Through Connections

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Complex Phase Connections

Figure 9.28 is similar to *Figure 9.27*, but with the added complication of primary phase swapping. The correspondence between the power system world and the SEL-651R-2 connections is first, at the top of *Figure 9.28*:

A ←→ 1
B ←→ 2
C ←→ 3

with Global settings VYCONN := ABC
(voltage terminals: V1Y ≈A-phase, V2Y ≈B-phase, V3Y ≈C-phase)

Then after the first primary phase swap at the top of the recloser, the correspondence between the power system world and the SEL-651R-2 connections is (via the control cable in *Figure 9.28*):

C ←→ 1
A ←→ 2
B ←→ 3

with Global settings IPCONN := CAB (current terminals: I1 ≈C-phase, I2 ≈A-phase, I3 ≈B-phase) and:

Coil 1 ←→ C-phase
Coil 2 ←→ A-phase
Coil 3 ←→ B-phase

The following close circuit example traces "B ←→ 3" correspondence in *Figure 9.28*:

CLOSE**B** → RCCL**3** → RCCL**3**X (Close **3**) → Coil **3** → **B**-phase

"A-**B**-C"　　　　　　　　"1-2-**3**"　　　　　　　　"A-**B**-C"
algorithms　　　　connections/transitions　　　power system

The following trip circuit example traces "C ←→ 1" correspondence in *Figure 9.28*:

TRIP**C** → RCTR**1** → RCTR**1**X (Trip **1**) → Coil **1** → **C**-phase

"A-B-**C**"　　　　　　　　"**1**-2-3"　　　　　　　　"A-B-**C**"
algorithms　　　　connections/transitions　　　power system

The following pole status circuit example traces "A ←→ 2" correspondence in *Figure 9.28*:

52A_**A** ← IN202 ← 52a**2** ← Coil **2** ← **A**-phase

"**A**-B-C"　　　　　　　　"1-**2**-3"　　　　　　　　"**A**-B-C"
algorithms　　　　connections/transitions　　　power system

After the primary phase swap at the bottom of the recloser in *Figure 9.28*, the correspondence between the power system world and the SEL-651R-2 connections is lastly:

B → 1
C → 2
A → 3

with Global settings VZCONN := BCA
(voltage terminals: V1Z ≈B-phase, V2Z ≈C-phase, V3Z ≈A-phase)

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More detailed connections for each recloser can be found in the corresponding installation section in *Section 2: Installation*.
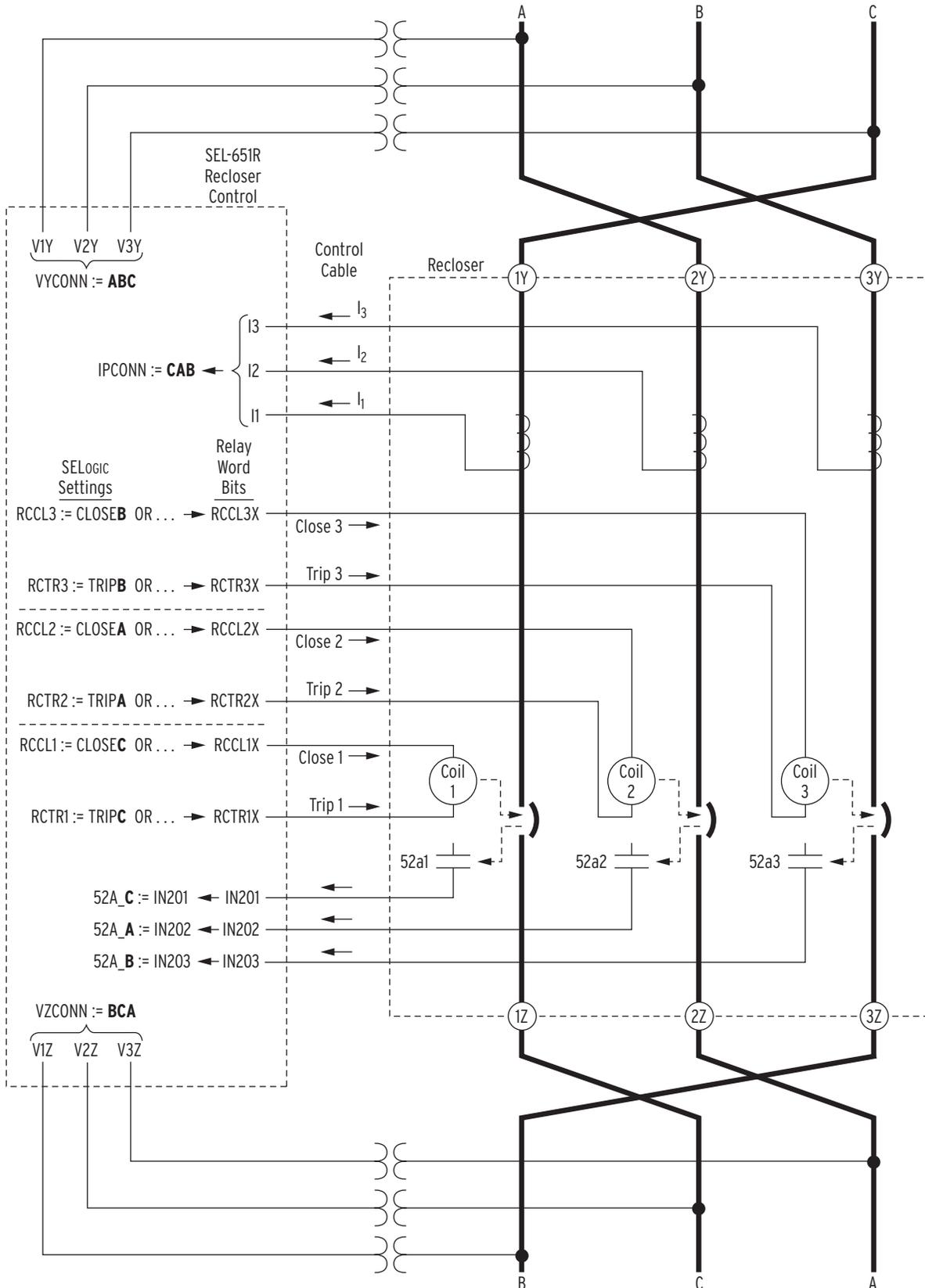
Figure 9.28   Single-Phase Trip Capable Recloser With Complex Connections

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Three-Phase vs. Single-Phase Operation

The trip and close settings (RCTR*n* and RCCL*n*, respectively) in *Figure 9.27* and *Figure 9.28* imply single-phase operation. But, three-phase operation can be realized, too, as shown in the settings possibilities in *Table 9.19* and *Table 9.20* ("… OR TRIP3P" and "… OR CLOSE3P").

Three-Phase Recloser Considerations

If a three-phase recloser is substituted for a single-phase recloser in *Figure 9.27* and *Figure 9.28*, the voltage and current connections and associated settings are essentially the same (although there are some current polarity connection differences; compare *Figure 2.49* with *Figure 2.52*). The major differences are with the trip/close signals and pole status (52a) coming through the control cable; compare with *Figure 2.50* with *Figure 2.54*.

Traditional Retrofit, Control-Powered Eaton NOVA, and G&W Control Power Viper -S reclosers are three-phase reclosers only (Global setting BKTYP := 3 and Group setting ESPB := N), where all three phases trip and close together. These reclosers have only one trip and close circuit and 52a status (see *Figure 2.50* and *Figure 2.60*, respectively). Three-phase operation in these reclosers is typically realized with settings:

RCTR1 := **TRIP3P** (see *Figure 5.1*)

RCCL1 := **CLOSE3P** (see *Figure 6.1*)

52A_3P := **SW1 AND NOT RCCL1X** (see *Figure 6.2*) Traditional Retrofit

or

52A_3P := **IN201** (see *Figure 6.2*) Control-Powered Eaton NOVA and G&W Control Power Viper-S

Display Point Settings

Refer to *Settings Sheet page SET.54* and *SET.60*.

The factory-default front-panel settings for DP01 and DP02 cause the message `FACTORY DEFAULT SETTINGS` to appear on the SEL-651R-2 rotating display. This message is not automatically disabled when settings are changed. The message is intended to remind the technician that the SEL-651R-2 needs to have settings applied before placing the recloser control into service. One of the first tasks the technician should perform is to defeat the display of the `FACTORY DEFAULT SETTINGS` message.

The message can be defeated by making Front-Panel settings

DP01 := **NA**

DP02 := **NA**

More details and instructions on display points are available in *Rotating Display on page 11.13*.

Enable Settings

Refer to the settings sheets that follow this section.

Several of the following Enable settings help limit the number of settings that must be entered when a feature is not required.

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Global Enable Settings (SET G Command)

The Global settings class contains eight enable settings. These settings control other settings as follows:

➤ EGNDSW: Enable Ground Current Switch. Group settings E50N and NDEMP are available for setting only if EGNDSW := N. Controls Relay Word bit GNDSW (see *Table 4.23* and associated text).

MULTI-RECLOSER INTERFACE
Global setting BKTYP is automatically set to BKTYP := 1 (and hidden) for the Multi-Recloser Interface on page 2.93.

➤ BKTYP: Breaker Type. Group settings ESPB, SPOD, 52A_A, 52A_B, and 52A_C are available for setting only if BKTYP := 1. Group setting 52A_3P is available for setting only if BKTYP := 3.

➤ VSELECT: Voltage Source Selection. Group settings VNOM, ELOAD, E32, EFLOC, ELOP, EPWR, ESSI, and Line Parameters are available for setting only if VSELECT is not set to OFF.

➤ FSELECT: Frequency Source Selection. Group settings E81, E81R, and E25 are available for setting only if FSELECT is not set to OFF.

➤ EICIS: Enable Independent Control Input Settings. Global settings IN101D–IN107D and IN201D–IN206D are available for setting only if EICIS := Y.

➤ EBMON: Breaker Monitor (Y, N). Hides ten settings when set to N.

➤ EPMU: Synchronized Phasor Measurement (Y, N). Hides as many as 16 settings when set to N. Also affects Port enable settings PROTO and EPMIP.

➤ DST_BEGM: Month to Begin DST (NA, 1–12). Hides seven settings when set to NA.
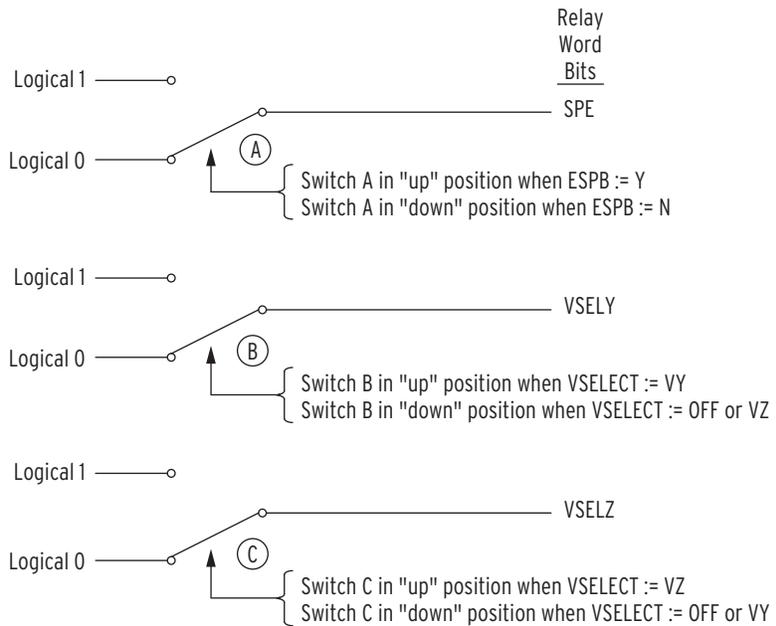
Figure 9.29   Operation of SPE, VSELY, and VSELZ Relay Word Bits From Enable Settings

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Settings
9.59
Settings Explanation
Wolfe

Group Enable Settings (SET n Command)

➤ ESPB: Enable Single Phase Breaker Settings. Numerous single-phase Group settings for auto-reclosing, tripping, and other close conditions are available for setting only if ESPB := Y. Numerous three-phase Group settings for auto-reclosing, tripping, and other close conditions are available for setting only if ESPB := N.

➤ E50P, E50N, E50G, E50Q: Instantaneous/Definite-Time Overcurrent Elements

➤ E51P, E51ABC, E51N1, E51N2, E51G1, E51G2, E51Q: Time-Overcurrent Elements

➤ ELOAD: Load Encroachment

➤ E32: Directional Control

➤ EVOLT: Voltage Elements

➤ E81: Frequency Elements

➤ E81R: Rate-of-Change-of-Frequency Elements

➤ EFLOC: Fault Location (does not hide any settings)

➤ ELOP: Loss-of-Potential

➤ EPWR: Power Elements

➤ E25: Synchronism Check

➤ E79: Autoreclosing

➤ ESOTF: Switch-Onto-Fault

➤ EDDSOTF: SOTF Disturbance Detector Supervision

➤ EDEM: Demand Metering (does not hide any settings)

➤ ESSI: Voltage Sag/Swell/Interruption

➤ EHIF: High-Impedance Fault Detection

➤ EHBL2: Second-Harmonic Blocking

➤ EMV: Math Variable Settings

Logic Enable Settings (SET L n Command)

➤ ELAT: Enable SELOGIC Latches

➤ ESV: Enable SELOGIC Variables/Timers

➤ ESC: Enable SELOGIC Counters

Front-Panel Enable Settings (SET F Command)

➤ EDP: Enable Display Points

➤ ELB: Enable Local Bits

9.60 | Settings
Settings Explanations

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Port Enable Settings (SET P n Command)

Serial Port Settings (Port 1, 2, 3, or F; Port F and Port 4 Are the Same Front-Serial Port)

NOTE: The Access jumper overrides the EPORT = N setting for the front-panel ports. Installing the Access jumper also causes the front-panel EIA-232 port to revert to factory-default settings for PROTO, SPEED, BITS, PARITY, STOP, and RTSCTS when EPORT = N.

NOTE: The Access jumper overrides the MAXACC setting for any enabled ports and allows the highest access level (C = Calibration).

➤ EPORT: Enable Port (Y, N). Disables the port and hides all port settings when set to N. The EPORT setting for Port F controls both the front-panel EIA-232 serial port F and the USB port.

➤ PROTO: Protocol. Controls availability of subsequent settings. When PROTO is set to SEL or DNP, another enable setting appears:

MAXACC: Maximum Access Level (0, 1, B, 2, C). Selects highest access level allowed on port by limiting the availability of commands **ACC**, **BAC**, **2AC**, or **CAL**. MAXACC for Port F can be set to 1, B, 2, or C and affects both serial port F and the USB port.

Ethernet Port Settings (Port 5)

➤ EPORT: Enable Port (Y, N). Hides all port settings when set to N.

➤ ETELNET: Enable Telnet (Y, N). Hides six settings when set to N. When ETELNET is set to Y, another enable setting appears:

NOTE: When ETELNET = Y, the Access jumper overrides the MAXACC setting and allows the Telnet session(s) to attain the highest access level (C = Calibration).

MAXACC: Maximum Access Level (0, 1, B, 2, C). Selects highest access level allowed on a Telnet session by limiting the availability of commands **ACC**, **BAC**, **2AC**, or **CAL**.

➤ EFTPSERV: Enable FTP (Y, N). Hides three settings when set to N.

➤ EHTTP: Enable HTTP Server (Y, N). Hides five settings when set to N. When EHTTP is set to Y, another enable setting appears:

HTTPACC: HTTP Maximum Access Level (1, 2). Selects highest access level allowed over the web server interface.

➤ E61850: Enable IEC 61850 Protocol (Y, N). Hides two settings when set to N (setting only present on relays ordered with IEC 61850).

➤ EDNP: Enable DNP Sessions (0–6). Controls availability of subsequent settings (as many as 33 settings per session).

➤ EPMIP: Enable PMU Processing (Y, N). Controls availability of as many as eight subsequent settings.

➤ EMODBUS: Enable Modbus (0–3). Controls availability of as many as seven subsequent settings.

➤ ESNTP: Enable SNTP client (OFF, UNICAST, MANYCAST, BROADCAST). Controls availability of as many as five subsequent settings.

PC Software

These enable settings are also present in the SEL-651R-2 driver for QuickSet. The effect of changing an enable setting is easy to see, because the associated setting field turns gray when it is unavailable. See *Section 3: PC Software* for more information on QuickSet.

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9.61
Settings
Factory-Default Settings

USB Port

No port settings are required for the USB port. However, the USB port is controlled by the previously described Port F (front-panel EIA-232 serial port) settings EPORT and MAXACC.

The PC operating system should prompt for a USB driver when a PC is connected to the relay. See *Establishing Communications Through Use of the USB Port on page 10.2* for further details on using the USB port.

Factory-Default Settings

Factory-default settings for a particular SEL-651R-2 are configured per the unit's part number. The factory-default settings in *Figure 9.30–Figure 9.39* are for an SEL-651R-2 configured with the following part number options (taken from the SEL-651R-2 Model Option Table):

➤ Control Cable Interface = Traditional Retrofit (14-pin)

➤ Secondary Input Voltage = (3) Eaton NOVA LEA inputs and (3) 120 Vac, 1M Lindsey SVMI LEA inputs

➤ Communications Port = 3 EIA-232, USB

➤ Communications Interface = (2) 100BASE-FX, EIA-485

➤ Power Supply = 120 Vac

Additional comments are included in *Figure 9.30–Figure 9.33*, touching primarily on setting variations because of:

➤ Interfacing with different recloser controls (corresponding to different Control Cable Interface options in the SEL-651R-2 Model Option Table)

➤ Connecting to different voltage sources (corresponding to different Secondary Input Voltage options in the SEL-651R-2 Model Option Table)

9.62 | Settings
Factory-Default Settings

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```
=>SHO G <Enter>

Global Settings:

General Settings:
NFREQ   := 60         PHROT   := ABC        DATE_F  := MDY
PWRDN_AC:= 180        PWRDN_WU:= 20
TESTBATT:=NA
FAULT   :=51P OR 51G1

Current and Voltage Connection Settings:
IPCONN  := ABC        EGNDSW  := Y          CTPOL   := POS
BKTYP   := 3
VYCONN  := ABC        VZCONN  := OFF
VSELECT := VY         FSELECT := VY         METHRES := N

Global Enable Settings:
EICIS   := N          EBMON   := N

Alarm Equations Settings:
SALARM  :=BADPASS OR CHGPASS OR SETCHG OR GRPSW OR ACCESSP OR PASNVAL

Setting Group Selection Settings:
TGR     := 0

Setting Group Selection SELogic Equations
SS1     :=PB04_PUL AND NOT SG1 AND LT05
SS2     :=PB04_PUL AND SG1 AND LT05
SS3     :=0
SS4     :=0
SS5     :=0
SS6     :=0
SS7     :=0
SS8     :=0

Voltage Ratio Correction Factors for Terminals V1Y, V2Y, V3Y:
V1YRCF  := 1.000     V2YRCF  := 1.000     V3YRCF  := 1.000

Voltage Ratio Correction Factors for Terminals V1Z, V2Z, V3Z:
V1ZRCF  := 1.000     V2ZRCF  := 1.000     V3ZRCF  := 1.000

Voltage Phase Angle Correction for Terminals V1Y, V2Y, V3Y:
V1YPAC  := 0.0       V2YPAC  := 0.0       V3YPAC  := 0.0

Voltage Phase Angle Correction for Terminals V1Z, V2Z, V3Z:
V1ZPAC  := 0.0       V2ZPAC  := 0.0       V3ZPAC  := 0.0

Data Reset Control:
RSTTRGT :=0
RST_DEM :=0
RST_PDM :=0
RST_BK  :=0
RST_HIS :=0
RST_ENE :=0
RST_MML :=0
RST_HAL :=0
RSTDNPE :=0

Synchronized Phasor Measurement Settings:
EPMU    := N

Distributed Network Protocol:
EVELOCK := 0          DNPSRC  := UTC

Time and Date Management:
IRIGC   := NONE     UTC_OFF := 0.00      DST_BEGM:= NA

=>
```

CTPOL := POS
CTPOL := NEG (Multi-Recloser interface with Global setting RECL_CFG := A3 only)

BKTYP := 1 (single-phase models and Tavrida OSM AI_2)
BKTYP := 3 (Traditional Retrofit, Control-Powered Eaton NOVA, G&W Control Power Viper-S, and Siemens SDR Three-Phase)

Voltage Ratio Correction Factor and Voltage Phase Angle Correction settings are available only for SEL-651R-2 Recloser Control models ordered with LEA inputs on VY or VZ terminals, respectively.

Figure 9.30   Global Settings (SHO G) With Factory-Default Values

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Settings 9.63
Factory-Default Settings
Wolfe

```
=>SHO <Enter>

Group 1

Group Settings

Identifier and Instrument Transformer Settings:
RID    :=FEEDER 1
TID    :=STATION A
CTR    := 1000.0    CTRN    := 1000.0    PTRY    := 150.00
PTRZ   := 120.00
VNOM   := 120.00

Enable Settings:
ESPB   := N          E50P    := N          E50N    := N
E50G   := N
E50Q   := N          E51P    := 2          E51ABC  := N
E51N1  := N          E51N2   := N          E51G1   := 2
E51G2  := N          E51Q    := N          ELOAD   := N
E32    := N
EVOLT  := VY         E81     := N          E81R    := N
EFLOC  := Y          ELOP    := N
EPWR   := N          E25     := N          E79     := 3
ESOTF  := N
EDEM   := THM        ESSI    := N          EHBL2   := N
EMV    := 1

Line Parameter Settings:
Z1MAG  := 32.10      Z1ANG   := 68.86      Z0MAG   := 95.70
Z0ANG  := 72.47
LL     := 4.84

Maximum-phase Time-Overcurrent Element J Settings:
51PJP   := 0.40      51PJC   := A          51PJTD  := 1.00
51PJCT  := 0.00      51PJMR  := 0.00

Maximum-phase Time-Overcurrent Element K Settings:
51PKP   := 0.40      51PKC   := C          51PKTD  := 1.00
51PKCT  := 0.00      51PKMR  := 0.00

Maximum-phase Time-Overcurrent SELogic Settings:
51PTC   :=1
51PSW   :=NOT (LTO4) OR (MVO1 <= 79SH3P) # DELAY CURVE SELECTED WHEN SHOT COUNT
MEETS OR EXCEEDS NUMBER OF FAST TRIPS (MVO1)

Ground Time-Overcurrent Element #1-J Settings:
51G1JP  := 0.100     51G1JC  := 1          51G1JTD := 1.00
51G1JCT := 0.00      51G1JMR := 0.00

Ground Time-Overcurrent Element #1-K Settings:
51G1KP  := 0.100     51G1KC  := 13         51G1KTD := 1.00
51G1KCT := 0.00      51G1KMR := 0.00

Ground Time-Overcurrent #1 SELogic Settings:
51G1TC  :=LTO1
51G1SW  :=NOT (LTO4) OR (MVO1 <= 79SH3P) # DELAY CURVE SELECTED WHEN SHOT COUNT
MEETS OR EXCEEDS NUMBER OF FAST TRIPS (MVO1)

Voltage Element Pickup Settings, Y-terminals:
27YP1P  := OFF       27YP2P  := OFF        27YPP1P := OFF
59YP1P  := 83.20
59YP2P  := OFF       59YPP1P := OFF        59YN1P  := OFF
59YN2P  := OFF
59YQ1P  := OFF       59YV1P  := OFF

Reclosing Relay Settings:
79OI1   := 300.00    79OI2   := 600.00     79OI3   := 600.00
79RSD   := 1800.00   79RSLD  := 600.00
79CLSD  := 900.00

Reclosing Relay SELogic Equations:
79RI3P  :=TRIP3P
79RIS3P :=52A3P OR 79CY3P
79DTL3P :=(NOT LTO2 OR NOT LTO6) AND (TRIP3P OR NOT 52A3P) OR PB12_PUL OR OC3
79DTL3X :=0

79DLS3P :=79LO3P
79SKP3P :=(51PT OR 51G1T) AND NOT LTO4 AND (79SH3P < MVO1) # SKIP TO DELAYED SHO
TS WHEN FAST CURVES DISABLED
79STL3P :=TRIP3P
79BRS3P :=0
79SEQ3P :=0
79CLS3P :=PWR_SRC1 AND TCCAP AND NOT (BTFAIL) # RECLOSE ONLY WHEN AC PRESENT, TR
IP/CLOSE CAPACITORS CHARGED, AND BATTERY HEALTHY

Pole-Open Settings:
3POD    := 0.50      50LP    := 0.05
```

PTRY := 120.00 (300 Vac inputs or Lindsey SVMI LEA inputs)
:= 266.67 (G&W Viper-ST, G&W Viper-LT, or ABB OVR/Gridshield (32-pin and 42-pin) with 8 Vac LEA inputs)
:= 150.00 (Eaton NOVA LEA inputs)
:= 234.50 (Tavrida OSM AI_2 and Tavrida OSM AI_4 with 8 Vac LEA inputs)
:= 39.36 (Eaton NOVA NX-T 15.5 kV with 8 Vac LEA inputs)

PTRZ := 120.00 (300 Vac inputs or Lindsey SVMI LEA inputs)
:= 266.67 (G&W Viper-ST, G&W Viper-LT, or ABB OVR/Gridshield (32-pin and 42-pin) with 8 Vac LEA inputs)
:= 234.50 (Tavrida OSM AI_2 and Tavrida OSM AI_4 with 8 Vac LEA inputs)
:= 36.25 (Siemens SDR LEA inputs)
:= 39.36 (Eaton NOVA NX-T 15.5 kV with 8 Vac LEA inputs)

Only available if relay supports Arc Sense technology

59YP1P := 104 (300 Vac inputs)
:= 46.80 (G&W Viper-ST or G&W Viper-LT with 8 Vac LEA inputs)
:= 83.20 (Eaton NOVA LEA inputs)

79DTL3X := 0 (Traditional Retrofit, ABB OVR/VR3S (24-pin), Control-Powered Eaton NOVA, G&W Control Power Viper-S, Tavrida OSM AI_2, and Siemens SDR Three-Phase)
:= R_TRIG SV02T # QUALIFIED YELLOW HANDLE OPERATION (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB Joslyn TriMod 600R, Eaton NOVA TS Triple-Single

79CLS3P := PWR_SRC1 AND TCCAP AND NOT (BTFAIL) # RECLOSE ONLY WHEN AC PRESENT, TRIP/CLOSE CAPACITORS CHARGED, AND BATTERY HEALTHY (Traditional Retrofit with AC power supply option)
79CLS3P := TCCAP AND NOT (BTFAIL) # RECLOSE ONLY WHEN TRIP/CLOSE CAPACITORS CHARGED, AND BATTERY HEALTHY (all other reclosers, except Traditional Retrofit, with AC power supply option)
79CLS3P := PWR_SRC1 AND TCCAP # RECLOSE ONLY WHEN DC PRESENT AND TRIP/CLOSE CAPACITORS CHARGED (Traditional Retrofit with DC power supply option)
79CLS3P := TCCAP # RECLOSE ONLY WHEN TRIP/CLOSE CAPACITORS CHARGED (all other reclosers, except Traditional Retrofit, with DC power supply option)

Figure 9.31   Group Settings (SHO) With Factory-Default Values

9.64 | Settings
Factory-Default Settings

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```
Demand Metering Settings:
DMTC   := 5          PDEMP    := OFF
GDEMP  := OFF        QDEMP    := OFF

50G High-Impedance (HIZ) Fault Detection Settings:
50GHIZP := OFF

Math Variable Settings:
MV01   := 2.00

Trip Logic Settings:
TDURD  := 40.00

Trip Logic SELogic Equations:
TR3P    :=51PT OR 51G1T OR PB12_PUL OR OC3
TR3X    :=0
TRQL3P  :=0
ULTR3P  :=1

Close Logic Settings:
CFD    := 60.00

Close Logic SELogic Equations:
52A_3P  :=SW1 AND NOT (RCCL1X)
CL3P    :=(PB11_PUL AND LT05 OR CC3) AND LT06 AND TCCAP # CLOSE FROM PUSHBUTTON
SUPERVISED BY LOCK. ALL CLOSING SUPERVISED BY HOT LINE TAG (LT06) AND TRIP/CLOSE
 CAPACITOR (TCCAP).
ULCL3P  :=TRIP3P OR (NOT IN201 AND SW1) OR NOT (LT06 AND TCCAP OR CLOSE3P) OR NO
T (LT05 OR CLOSE3P OR CC3 OR 79CY3P) # SW1 ONLY ACTIVE FOR 14-PIN RECLOSERS

Recloser Interface Trip and Close Settings:
RCTR1   :=TRIP3P OR TRIPA OR TRIPB OR TRIPC
RCCL1   :=CLOSE3P

=>
```

Only available if relay supports Arc Sense technology

TR3X := 0 (Traditional Retrofit, ABB OVR/VR3S (24-pin), Control-Powered Eaton NOVA, G&W Control Power Viper-S, ABB Joslyn TriMod 600R, Tavrida OSM AI_2, and Siemens SDR Three-Phase)

TR3X := R_TRIG SV02T # QUALIFIED YELLOW HANDLE OPERATION (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), Eaton NOVA-TS or NOVA-STS Triple-Single, and Siemens SDR Triple-Single)

52A_3P := SW1 AND NOT(RCCL1X) (Traditional Retrofit)
52A_3P := IN201 (Control-Powered Eaton NOVA, G&W Control Power Viper-S, and Siemens SDR Three-Phase)
52A_3P replaced by 52A_A :=IN201, 52A_B :=IN202, and 52A_C :=IN203 (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB Joslyn TriMod 600R, Eaton NOVA-TS or NOVA-STS Triple-Single, and Siemens SDR Triple-Single)
52A_3P replaced by 52A_A :=NOT IN201, 52A_B :=NOT IN202, 52A_C :=NOT IN203 (ABB OVR/VR3S (24-pin), and Tavrida OSM AI_2)

ULCL3P := TRIP3P OR (NOT IN201 AND SW1) OR NOT (LT06 AND TCCAP OR CLOSE3P) OR NOT (LT05 OR CLOSE3P OR CC3 OR 79CY3P) # SW1 ONLY ACTIVE FOR 14-PIN RECLOSERS (Traditional Retrofit)
ULCL3P := TRIP3P OR NOT (LT06 AND TCCAP OR CLOSE3P) OR NOT (LT05 OR CLOSE3P OR CC3 OR 79CY3P) (all other reclosers, except Traditional Retrofit)

Figure 9.31   Group Settings (SHO) With Factory-Default Values (Continued)

```
=>SHO L <Enter>
SELogic group 1

Logic Settings

SELogic Enable Settings:
ELAT   := 9          ESV   := 1          ESC   := 1

Latch Bits Set/Reset SELogic Equations:
SET01 :=PB01_PUL AND NOT (LT01) AND LT05 # GROUND ENABLED
RST01 :=PB01_PUL AND LT01 AND LT05
SET02 :=PB02_PUL AND NOT (LT02) AND LT05 AND LT06 # RECLOSE ENABLED
RST02 :=PB02_PUL AND LT02 AND LT05 OR NOT (LT06) OR (79SH3P = -1.00) # LAST TE
RM IS "RECLOSING RELAY DEFEATED"
SET03 :=PB03_PUL AND NOT (LT03) AND LT05 # REMOTE ENABLED
RST03 :=PB03_PUL AND LT03 AND LT05
SET04 :=PB05_PUL AND NOT (LT04) AND LT05 # FAST CURVE ENABLED
RST04 :=PB05_PUL AND LT04 AND LT05
SET05 :=R_TRIG SCO1QU AND NOT (LT05) # LOCK PUSH BUTTONS, MUST PRESS FOR THREE
 SECONDS (LOCKED WHEN LT05 DEASSERTED)
RST05 :=R_TRIG SCO1QU AND LT05
SET06 :=PB07_PUL AND NOT (LT06) AND LT05 # HOT LINE TAG (WHEN LT06 DEASSERTED)
RST06 :=PB07_PUL AND LT06 AND LT05
SET07 :=PB08_PUL AND NOT (LT07) AND LT05 # AUX 1
RST07 :=PB08_PUL AND LT07 AND LT05
SET08 :=PB09_PUL AND NOT (LT08) AND LT05 # AUX 2
RST08 :=PB09_PUL AND LT08 AND LT05
SET09 :=PB10_PUL AND NOT (LT09) AND LT05 # AUX 3
RST09 :=PB10_PUL AND LT09 AND LT05

SELogic Variable and Timer Settings:
SV01PU  := 29.75     SV01DO   := 29.75
SV01    :=NOT (SV01T) AND PB06 # 1 HZ BLINK GENERATOR FOR LOCK PUSH BUTTON

SELogic Counter Settings:
SCO1PV  := 3
SCO1R   :=NOT (PB06)
SCO1LD  :=0 # SET TO 1 TO DEFEAT 3 BLINK DELAY
SCO1CU  :=SV01T # COUNT THE BLINKS FOR LOCK PUSH BUTTONS CONTROL
SCO1CD  :=0
```

ESV := 1 (Traditional Retrofit, ABB OVR/VR3S (24-pin), Control-Powered Eaton NOVA, G&W Control Power Viper-S, and Siemens SDR Three-Phase)
ESV := 2 (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB Joslyn TriMod 600R, Eaton NOVA-TS or NOVA-STS Triple-Single, and Siemens SDR Triple-Single)
ESV := 3 (Tavrida OSM AI_2, Multi-Recloser Interface)

SV02PU := 0.00 and SV02DO := 0.00 (Traditional Retrofit, ABB OVR/VR3S (24-pin), Control-Powered Eaton NOVA, G&W Control Power Viper-S, and Siemens SDR Three-Phase)
SV02PU := 5.00 and SV02DO := 60.00 (G&W Viper-ST, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), ABB Joslyn TriMod 600R, Eaton NOVA-TS or NOVA-STS Triple-Single, and Siemens SDR Triple-Single, Multi-Recloser Interface)
SV02PU := 150.00 and SV02DO := 150.00 (Tavrida OSM AI_2)

SV02 := NA (Traditional Retrofit, ABB OVR/VR3S (24-pin), Control-Powered Eaton NOVA, G&W Control Power Viper-S, and Siemens SDR Three-Phase)
SV02 := IN204 # QUALIFY YELLOW HANDLE OPERATION (G&W Viper-T, G&W Viper-LT, ABB Elastimold MVR, ABB OVR/Gridshield (32-pin), and Siemens SDR Triple-Single)
SV02 := NOT IN204 # QUALIFY YELLOW HANDLE OPERATION (ABB Joslyn TriMod 600R)
SV02 := IN204 OR IN205 OR IN206 # QUALIFY YELLOW HANDLE OPERATION (Eaton NOVA-TS or NOVA-STS Triple-Single)
SV02 := IN105 # QUALIFY YELLOW HANDLE OPERATION (Tavrida OSM AI_2)
SV02 := 69_YH # QUALIFY YELLOW HANDLE OPERATION (Multi-Recloser Interface)

SV03PU := 150.00 and SV03DO := 150.00 (Tavrida OSM AI_2, Multi-Recloser Interface)

SV03 := NOT(IN105) AND 52A3P # QUALIFY DISCONNECTED CABLE (Tavrida OSM AI_2)
SV03 := ((NOT IN105 AND NOT IN201 OR NOT IN106 AND NOT IN202 OR NOT IN107 AND NOT IN203) AND (A1_CFG OR A3_CFG) OR 69_YH AND 52A3P AND A2_CFG) # QUALIFY DISCONNECTED CABLE (Multi-Recloser Interface)

Figure 9.32   Logic Settings (SHO L) With Factory-Default Values

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Settings 9.65
Factory-Default Settings

```
Output Contact Equations:
OUT101  :=0
OUT102  :=0
OUT103  :=0
OUT104  :=0
OUT105  :=0
OUT106  :=0
OUT107  :=0
OUT108  :=0
OUT201  :=NOT (SALARM OR HALARM)
OUT202  :=0

Mirrored Bits Transmit Equations:
TMB1A   :=NA
TMB2A   :=NA
TMB3A   :=NA
TMB4A   :=NA
TMB5A   :=NA
TMB6A   :=NA
TMB7A   :=NA
TMB8A   :=NA
TMB1B   :=NA
TMB2B   :=NA
TMB3B   :=NA
TMB4B   :=NA
TMB5B   :=NA
TMB6B   :=NA
TMB7B   :=NA
TMB8B   :=NA

PMU Trigger Equations
PMTRIG  :=0
TREA1   :=0
TREA2   :=0
TREA3   :=0
TREA4   :=0

=>
```

Figure 9.32   Logic Settings (SHO L) With Factory-Default Values (Continued)

```
=>SHO F <Enter>

Front Panel Settings

General Settings:
EDP    := 2            ELB    := N        FP_TO   := 15
SCROLD := 2            FP_CONT := 8
FPNGD  := IG           FPVYD  := ON       FPVZD   := OFF
LEDENAC := G           LEDTRAC := R       RSTLED  := Y
                                                 EDP := 4 (Tavrida OSM AI_2,
                                                 Multi-Recloser Interface)
Operator Control LED Settings:
PB01LEDC:= AO
PB01_LED:=LTO1 # GROUND ENABLED
PB02LEDC:= AO
PB02_LED:=LTO2 # RECLOSE ENABLED
PB03LEDC:= AO
PB03_LED:=O # REMOTE ENABLED
PB04LEDC:= AO
PB04_LED:=NOT (SG1) # ALT SETTINGS
PB05LEDC:= AO
PB05_LED:=LTO4 # FAST CURVE ENABLED
PB06LEDC:= AO
PB06_LED:=NOT (LTO5 AND NOT (SV01T AND PB06 AND NOT (SCO1QU)) OR NOT (LTO5) AND
SV01T AND PB06 AND NOT (SCO1QU)) # LOCK PUSH BUTTONS
PB07LEDC:= AO
PB07_LED:=NOT (LTO6) # HOT LINE TAG
PB08LEDC:= AO
PB08_LED:=O # AUX 1
PB09LEDC:= AO
PB09_LED:=O # AUX 2
PB10LEDC:= AO
PB10_LED:=O # AUX 3
PB11LEDC:= RO
PB11_LED:=52A3P # RECLOSER CLOSED
PB12LEDC:= GO
PB12_LED:=NOT (52A3P) # RECLOSER OPEN
Target LED Settings:
TO1LEDL := N          TO1LEDC := G
TO1_LED :=PWR_SRC1 # SUPPLY
TO2LEDL := N          TO2LEDC := R
TO2_LED :=BTFAIL # BATTERY PROBLEM
```

**Figure 9.33   Front-Panel Settings (SHO F) With Factory-Default Values
(Without Tricolor LED Option)**

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Factory-Default Settings

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```
T03LEDL := Y          T03LEDC := R
T03_LED :=PHASE_A # A FAULT
T04LEDL := Y          T04LEDC := R
T04_LED :=PHASE_B # B FAULT
T05LEDL := Y          T05LEDC := R
T05_LED :=PHASE_C # C FAULT
T06LEDL := Y          T06LEDC := R
T06_LED :=51G1 # GROUND
T07LEDL := Y          T07LEDC := R
T07_LED :=0 # SEF
T08LEDL := Y          T08LEDC := R
T08_LED :=NOT (51G1S) AND 51G1T OR NOT (51PS) AND 51PT # FAST CURVE
T09LEDL := Y          T09LEDC := R
T09_LED :=51G1S AND 51G1T OR 51PS AND 51PT # DELAY CURVE
T10LEDL := Y          T10LEDC := R
T10_LED :=0 # HIGH CURRENT
T11LEDL := Y          T11LEDC := R
T11_LED :=0 # FREQUENCY
T12LEDL := Y          T12LEDC := R
T12_LED :=0 # VOLTAGE
T13LEDL := N          T13LEDC := G
T13_LED :=79RS3P # 79 RESET
T14LEDL := N          T14LEDC := R
T14_LED :=79CY3P # 79 CYCLE
T15LEDL := N          T15LEDC := R
T15_LED :=79LO3P # 79 LOCKOUT
T16LEDL := N          T16LEDC := R
T16_LED :=51P OR 51G1 # ABOVE MIN TRIP
T17LEDL := N          T17LEDC := R
T17_LED :=0 # COLD LOAD SCHEME ON
T18LEDL := N          T18LEDC := R
T18_LED :=0 # REVERSE POWER
T19LEDL := N          T19LEDC := R
T19_LED :=59YA1 # VAY ON
T20LEDL := N          T20LEDC := R
T20_LED :=59YB1 # VBY ON
T21LEDL := N          T21LEDC := R
T21_LED :=59YC1 # VCY ON
T22LEDL := N          T22LEDC := R
T22_LED :=0 # VAZ ON
T23LEDL := N          T23LEDC := R
T23_LED :=0 # VBZ ON
T24LEDL := N          T24LEDC := R
T24_LED :=0 # VCZ ON


Display Point Settings:
DP01    :=1,"FACTORY DEFAULT"
DP02    :=1,"   SETTINGS"


=>
```

```
DP03 := SV02T,"YELLOW HANDLE",RESET,LOCK-OPEN
        (Tavrida OSM AI_2)
DP03 := SV02T,"YELLOW HANDLE","LOCK-OPEN","RESET"
        (Multi-Recloser Interface)
DP04 := SV03T,"CABLE DISCONNECTED" (Tavrida OSM AI_2, Multi-
Recloser Interface)
```

Figure 9.33   Front-Panel Settings (SHO F) With Factory-Default Values (Without Tricolor LED Option) (Continued)

```
=>SHO R <Enter>

Report Settings

Sequential Events Recorder Trigger Lists:
SER1    := TRIP3P,51P,51PT,51G1,51G1T,PB12_PUL,OC3
SER2    := CLOSE3P,52A3P,CF3P,79RS3P,79CY3P,79LO3P,RCSF3P,SHO3P,SH13P,SH23P
SH33P,SH43P,PB11_PUL,CC3
SER3    := PWR_SRC1,TOSLP,BTFAIL,DTFAIL
SER4    := 0

Event Report Settings:
LER     := 15         PRE     := 4
ER      :=R_TRIG 51P OR R_TRIG 51G1


Load Profile Settings:
LDLIST  := 0
LDAR    := 15

HIF Event Report Settings: ─────────────── Only available if relay supports Arc Sense technology
HIFLER  := 10
HIFER   := NA


=>
```

Figure 9.34   Report Settings (SHO R) With Factory-Default Values

```
=>SHO P 1 <Enter>
Port 1

EPORT   := Y
PROTO   := SEL       MAXACC  := 2
SPEED   := 9600      BITS    := 8        PARITY  := N
STOP    := 1         T_OUT   := 15
AUTO    := N         FASTOP  := N
=>
```

Figure 9.35   Port 1 Settings (SHO P 1) With Factory-Default Values

```
=>SHO P 2 <Enter>

Port 2

EPORT   := Y
PROTO   := SEL       MAXACC  := 2
SPEED   := 9600      BITS    := 8        PARITY  := N
STOP    := 1         RTSCTS  := N        T_OUT   := 15
AUTO    := N         FASTOP  := N
=>
```

Figure 9.36   Port 2 Settings (SHO P 2) With Factory-Default Values

```
=>SHO P 3 <Enter>
Port 3

EPORT   := Y
PROTO   := SEL       MAXACC  := 2
SPEED   := 9600      BITS    := 8        PARITY  := N
STOP    := 1         RTSCTS  := N        T_OUT   := 15
AUTO    := N         FASTOP  := N
=>
```

Figure 9.37   Port 3 Settings (SHO P 3) With Factory-Default Values

```
=>SHO P F <Enter>
Port F

EPORT   := Y
PROTO   := SEL       MAXACC  := C
SPEED   := 9600      BITS    := 8        PARITY  := N
STOP    := 1         RTSCTS  := N        T_OUT   := 15
AUTO    := N         FASTOP  := N
=>
NOTE: Command SHO P 4 also gives Port F settings.

=>SHO P 4 <Enter>
Port F

EPORT   := Y
PROTO   := SEL       MAXACC  := C
SPEED   := 9600      BITS    := 8        PARITY  := N
STOP    := 1         RTSCTS  := N        T_OUT   := 15
AUTO    := N         FASTOP  := N
=>
```

Figure 9.38   Port F Settings (SHO P F) With Factory-Default Values

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```
=>SHO P 5 <Enter>
Port 5

EPORT   := Y          IPADDR  :=192.168.1.2
SUBNETM :=255.255.255.0
DEFRTR  :=192.168.1.1
ETCPKA  := Y          KAIDLE  := 10        KAINTV  := 10
KACNT   := 5
NETMODE := FAILOVER  FTIME   := 1.00      NETPORT := A

ETELNET := N
EFTPSERV:= N
EHTTP   := N
E61850  := N
EDNP    := 0
EMODBUS := 0
ESNTP   := OFF
=>
```

Figure 9.39   Port 5 Settings (SHO P 5) With Factory-Default Values

Settings Sheets

NOTE: If the QuickSet settings editor is being used in conjunction with these settings sheets, some differences in setting order will be seen between the two formats, especially in the location of the enable settings. The Print option in QuickSet will list the settings in a similar order as these settings sheets.

The settings sheets that follow include the definition and input range for each setting in the SEL-651R-2. Many of the settings categories in the settings sheets include a reference to a page, table, or figure (in parentheses) that further explains the settings.

Date _____

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SEL-651R-2 Settings Sheets

Global Settings

(Serial Port Command SET G and Front-Panel SET/SHOW Global Menu*)

* SELOGIC control equations can be viewed, but not changed, via the front-panel `Set/Show > Global Menu`.
For most applications, make Global settings (page *SET.1–SET.7*) before making the Group 1–8 settings.

General Settings

See General (Global Settings) on page 9.27.

Nominal Frequency (50, 60 Hz)	**NFREQ**	:= _____
Phase Rotation (ABC, ACB)	**PHROT**	:= _____
Date Format (MDY, YMD, DMY)	**DATE_F**	:= _____

See Battery System Monitor on page 8.39.

Power-Off Delay After AC Loss (OFF, 1–1440 min)	**PWRDN_AC**	:= _____
Power-Off Delay After Wake Up (OFF, 1–1440 min)	**PWRDN_WU**	:= _____

Request Battery Test SELOGIC Equation
   TESTBATT   := _____

See SELOGIC Control Equation Setting FAULT on page 5.18.

Fault Condition SELOGIC Equation
   FAULT   := _____

Current and Voltage Connection Settings

See Multi-Recloser Interface on page 2.93.

Recloser Configuration (A1, A2, A3)	**RECL_CFG**	:= _____

See Current and Voltage Connections (Global Settings) on page 9.28.

I1, I2, I3 Current Terminal Connections (ABC, ACB, BAC, BCA, CAB, CBA)	**IPCONN**	:= _____
Enable Ground Current Switch (Y, N)	**EGNDSW**	:= _____
Current Transformer Polarity (POS, NEG)	**CTPOL**	:= _____
Breaker Type (Single-Phase = 1, Three-Phase = 3)	**BKTYP**	:= _____
VY Voltage Terminal Connections (OFF, Combination of A, B, C) *Valid combinations: ABC, ACB, BAC, BCA, CAB, CBA, A, B, C, AB, BC, CA*	**VYCONN**	:= _____

VZ Voltage Terminal Connections   **VZCONN**   := _____
(OFF, Combination of A, B, C)
Valid combinations: ABC, ACB, BAC,
BCA, CAB, CBA, A, B, C, AB, BC, CA

Enable Phantom Voltage Source (OFF, VY, VZ)   **EPHANT**   := _____
Setting EPHANT is only available when one or both of VYCONN or
VZCONN is set to single-phase voltages A, B, C, AB, BC, or CA

Voltage Source Selection (OFF, VY, VZ)   **VSELECT**   := _____
Setting VSELECT is only available when one or both of VYCONN or
VZCONN is set to three-phase combinations ABC, ACB, BAC, BCA,
CAB, or CBA

Frequency Source Selection (OFF, VY, VZ)   **FSELECT**   := _____
Setting FSELECT is only available when one or both of VYCONN or
VZCONN is not set to OFF

Meter Cutoff Threshold (Y, N, E)   **METHRES**   := _____
(see *Small-Signal Cutoff for Metering on page 8.19*)

Global Enable Settings

Independent Control Input Settings (Y, N)   **EICIS**   := _____

Breaker Monitor (Y, N)   **EBMON**   := _____

Alarm SELOGIC Equation
  SALARM   := _____

Optoisolated Input Timers

See Figure 7.18.

Make the following settings when the SEL-651R-2 is ordered with extra input/outputs, and if preceding enable
setting EICIS := Y.

Input IN101–IN102 Debounce Time Settings   **IN101D**   := _____
  (AC, 0.00–2.00 cycles in 0.0625-cycle steps; when ordered   **IN102D**   := _____
  with 125 Vdc inputs)
  (0.00–2.00 cycles in 0.0625-cycle steps when ordered *without*
  125 Vdc inputs)

Input IN103–IN107 Debounce Time Settings   **IN103D**   := _____
  (0.00–2.00 cycles in 0.0625-cycle steps)   **IN104D**   := _____
                                                    IN105D   := _____
                                                    IN106D   := _____
                                                    IN107D   := _____

Status Input Timers

See Figure 7.17.

Make the following settings when the preceding enable setting EICIS := Y.

Input IN201–IN206 Debounce Time   **IN201D**   := _____
  (0.00–2.00 cycles in 0.0625-cycle steps)   **IN202D**   := _____
                                                    IN203D   := _____
                                                    IN204D   := _____
                                                    IN205D   := _____

Date _____

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IN206D   := _____

Settings Group Change Delay

See Multiple Settings Groups on page 7.23.

Group Change Delay   **TGR**   := _____
   (0.00–16000.00 cycles in 0.25-cycle steps)

Settings Group Selection SELᴏɢɪᴄ Equations

See Table 7.8.

Select Settings Group 1
SS1   := _____

Select Settings Group 2
SS2   := _____

Select Settings Group 3
SS3   := _____

Select Settings Group 4
SS4   := _____

Select Settings Group 5
SS5   := _____

Select Settings Group 6
SS6   := _____

Select Settings Group 7
SS7   := _____

Select Settings Group 8
SS8   := _____

Voltage Ratio Correction Factors for VY-Terminal Voltage Inputs

See Voltage Ratio Correction Factors for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.34.

Make the following settings when the SEL-651R-2 is ordered with LEA ac inputs on the VY terminals.

Ratio Correction Factor (0.500–1.500)   **V1YRCF**   := _____

Ratio Correction Factor (0.500–1.500)   **V2YRCF**   := _____

Ratio Correction Factor (0.500–1.500)   **V3YRCF**   := _____

Voltage Ratio Correction Factors for VZ-Terminal Voltage Inputs

See Voltage Ratio Correction Factors for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.34.

Make the following settings when the SEL-651R-2 is ordered with LEA ac inputs on the VZ terminals.

Ratio Correction Factor (0.500–1.500)   **V1ZRCF**   := _____

Ratio Correction Factor (0.500–1.500)   **V2ZRCF**   := _____

Ratio Correction Factor (0.500–1.500)   **V3ZRCF**   := _____

Voltage Phase Angle Correction for VY Terminals

See Voltage Phase Angle Correction Settings for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.36.

Make the following settings when the SEL-651R-2 is ordered with LEA ac inputs on the VY terminals.

Phase Angle Correction (–10.0 to 0 degrees)	**V1YPAC**	:= _____
Phase Angle Correction (–10.0 to 0 degrees)	**V2YPAC**	:= _____
Phase Angle Correction (–10.0 to 0 degrees)	**V3YPAC**	:= _____

Voltage Phase Angle Correction for VZ Terminals

See Voltage Phase Angle Correction Settings for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.36.

Make the following settings when the SEL-651R-2 is ordered with LEA ac inputs on the VZ terminals.

Phase Angle Correction (–10.0 to 0 degrees)	**V1ZPAC**	:= _____
Phase Angle Correction (–10.0 to 0 degrees)	**V2ZPAC**	:= _____
Phase Angle Correction (–10.0 to 0 degrees)	**V3ZPAC**	:= _____

Breaker Monitor Settings

See Breaker Monitor Setting Example on page 8.26.

Make the following settings if preceding enable setting EBMON := Y.

Close/Open Set Point 1—Max. (0–65000 operations)	**COSP1**	:= _____
Close/Open Set Point 2—Mid. (0–65000 operations)	**COSP2**	:= _____
Close/Open Set Point 3—Min. (0–65000 operations)	**COSP3**	:= _____

kA Interrupted Set Point 1—Min. (0.00–999.00 kA primary in 0.01 kA steps)	**KASP1**	:= _____
kA Interrupted Set Point 2—Mid. (0.00–999.00 kA primary in 0.01 kA steps)	**KASP2**	:= _____
kA Interrupted Set Point 3—Max. (0.00–999.00 kA primary in 0.01 kA steps)	**KASP3**	:= _____

NOTES:

➤ COSP1 must be set greater than COSP2.

➤ COSP2 must be set greater than or equal to COSP3.

➤ KASP1 must be set less than KASP2.

➤ If COSP2 is set the same as COSP3, then KASP2 must be set the same as KASP3.

➤ KASP3 must be set at least 5 times (but no more than 100 times. the KASP1 setting value.

➤ KASP2 must be set less than or equal to KASP3.

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Breaker Monitor Initiate SELᴏɢɪᴄ Equations

See Breaker/Recloser Contact Wear Monitor on page 8.23.

Make setting BKMON3P when setting BKTYP := 3.

BKMON3P := _____

Make settings BKMONA, BKMONB, and BKMONC when setting BKTYP := 1.

BKMONA := _____

BKMONB := _____

BKMONC := _____

Data Reset Control SELᴏɢɪᴄ Equations

Target Reset SELᴏɢɪᴄ Equation
(see *Programmable Front-Panel Target LEDs on page 5.15*)

RSTTRGT := _____

Reset Demand Metering
(see *Demand Metering on page 8.6*)

RST_DEM := _____

Reset Peak Demand Metering
(see *Demand Metering on page 8.6*)

RST_PDM := _____

Reset Breaker/Recloser Contact Wear Monitor
(see *Breaker/Recloser Contact Wear Monitor on page 8.23*)

RST_BK := _____

Reset Event History
(see *Clearing Standard Event Report Buffer on page 12.12*)

RST_HIS := _____

Reset Energy Metering (see *Energy Metering on page 8.15*)

RST_ENE := _____

Reset Maximum/Minimum Metering
(see *Maximum/Minimum Metering on page 8.17*)

RST_MML := _____

Reset Hardware Alarm Bit
(see *Status Warning and Status Failure on page 13.7*)

RST_HAL := _____

Reset DNP Event Registers/Buffers
(See *Reading Relay Events on page E.39*)

RSTDNPE := _____

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Synchronized Phasor Measurement Settings

See Appendix J.

Synchronized Phasor Measurement (Y, N)	**EPMU**	:= _____

Message Rate (messages per second)   **MRATE** := _____
(1, 2, 4, 5, 10, 12, 15, 20, 30, 60 when NFREQ = 60)
(1, 2, 5, 10, 25, 50 when NFREQ = 50)

Phasor Measurement Unit (PMU) Application (F, N)   **PMAPP** := _____

NOTE: F = Fast Response, N = Narrow Bandwidth

Frequency Based Phasor Compensation (Y, N)   **PHCOMP** := _____

Station Name (16 characters, mixed case)   **PMSTN** := _____

NOTE: Cannot contain the following characters: ? / \ < > * | : ; [ ] $ % { }.

Phasor Measurement Unit (PMU) Hardware ID (1–65534)   **PMID** := _____

Include Voltage Terminal   **PHVOLT** := _____
(Y = VY, Z = VZ, ALL = VY and VZ)

Phasor Data Set, Voltages (V1, PH, ALL, NA)   **PHDATAV** := _____

VY Terminal Voltage Angle Compensation Factor   **VYCOMP** := _____
(–179.99 to +180 degrees in 0.01 degree steps)

VZ Terminal Voltage Angle Compensation Factor   **VZCOMP** := _____
(–179.99 to +180 degrees in 0.01 degree steps)

Phasor Data Set, Currents (I1, PH, ALL, NA)   **PHDATAI** := _____

Phase Current Angle Compensation Factor   **IPCOMP** := _____
(–179.99 to +180 degrees in 0.01 degree steps)

Neutral (IN) Current Angle Compensation Factor   **INCOMP** := _____
(–179.99 to +180 degrees in 0.01 degree steps)

Make settings PHNR and PHFMT when PHDATAV ≠ NA or PHDATAI ≠ NA.

Phasor Numeric Representation (I = Integer, F = Floating Point)   **PHNR** := _____

Phasor Format   **PHFMT** := _____
(R = Rectangular coordinates, P = Polar coordinates)

Frequency Numeric Representation   **FNR** := _____
(I = Integer, F = Floating Point)

Number of 16-bit Digital Status Words (0, 1, 2, 3, 4)   **NUMDSW** := _____

DNP

See Appendix E.

Event Summary Lock Period (0 to 1000 seconds)   **EVELOCK** := _____

DNP Session Time Base (LOCAL, UTC)   **DNPSRC** := _____

Date _____

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Time and Date Management

See Section 10 and Appendix J.

IRIG-B Control Bits Definition (NONE, C37.118)   **IRIGC**   := _____

Offset from UTC (–24.00 to 24.00 hours in 0.01 hour steps)   **UTC_OFF**   := _____

NOTE: This setting does not apply when IRIG-B active (TSOK or TIRIG asserted).

Daylight-Saving Time Settings

See Automatic Daylight-Saving Time Settings (Global Settings) on page 9.39.

NOTE: DST settings do not apply when IRIG-B active (TSOK or TIRIG asserted).

Month to Begin DST (NA, 1–12)   **DST_BEGM**   := _____

Make the following settings when DST_BEGM ≠ NA.

Week of the Month to Begin DST (1–3, L = Last)   **DST_BEGW**   := _____

Day of the Week to Begin DST (SUN–SAT)   **DST_BEGD**   := _____

Local Hour to Begin DST (0–23)   **DST_BEGH**   := _____

Month to End DST (NA, 1–12)   **DST_ENDM**   := _____

Week of the Month to End DST (1–3, L = Last)   **DST_ENDW**   := _____

Day of the Week to End DST (SUN–SAT)   **DST_ENDD**   := _____

Local Hour to End DST (0–23)   **DST_ENDH**   := _____

Group Settings

(Serial Port Command SET n[a] and Front-Panel Set/Show Group menu[b])

[a] Where n = Group 1–8; defaults to active group.
[b] SELOGIC control equations can be viewed, but not changed, via the front-panel SET/SHOW Group Menu.

Identifier Labels

See Identifier Labels (Group Settings) on page 9.40.

Relay Identifier (30 characters) (0–9, A–Z, -, /, ., space)

RID   := _____

Terminal Identifier (30 characters) (0–9, A–Z, -, /, ., space)

TID   := _____

Current and Potential Transformer Ratios

See Current Transformer (CT) Ratios (Group Settings) on page 9.41.

Phase (IA, IB, IC) Current Transformer Ratio (1.0–6000.0)   **CTR**   := _____

Neutral (IN) Current Transformer Ratio (1.0–6000.0)   **CTRN**   := _____

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VY-Side (V1Y, V2Y, V3Y)
Potential Transformer Ratio (1.00–10000.00) **PTRY** := _____

For LEA inputs, see Potential Transformer (PT) Ratios (Group Settings) on page 9.42 for PTRY and/or PTRZ setting calculation.

VZ-Side (V1Z, V2Z, V3Z)
Potential Transformer Ratio (1.00–10000.00) **PTRZ** := _____

Nominal Voltage (line-to-neutral) on VSELECT-designated
side (25.00–300.00 V secondary) **VNOM** := _____
(*When VSELECT := OFF, VNOM is hidden*)

See Table 9.17 for proper VNOM setting adjustment when LEA inputs are used.

Enable Settings

Set Global setting BKTYP := 1 for single-phase reclosers–see Breaker/Recloser Type Setting (BKTYP) and Enable Single-Phase Breaker Setting (ESPB) on page 9.30.

Make ESPB setting when Global setting BKTYP := 1.

Single Phase Breaker Settings (Y, N) **ESPB** := _____
When BKTYP := 3, ESPB := N

Instantaneous/Definite-Time Overcurrent Enable Settings

Phase Element Levels (N, 1–6) **E50P** := _____
(see *Figure 4.1–Figure 4.7*)

Make E50N setting when Global setting EGNDSW is set to N.

Neutral Element Levels—Channel IN (N, 1–6) **E50N** := _____
(When EGNDSW := Y, E50 := N; see *Figure 4.10* and
Figure 4.11)

Ground Element Levels (N, 1–6) **E50G** := _____
(see *Figure 4.12* and *Figure 4.13*)

Negative-Sequence Element Levels (N, 1–6) **E50Q** := _____
(see *Figure 4.14* and *Figure 4.15*)

Time-Overcurrent Enable Settings

See Table 4.1.

Maximum-Phase Elements (N, 1, 2) **E51P** := _____

Single-Phase Elements (N, 1, 2) **E51ABC** := _____

Neutral #1 Elements (N, 1, 2) **E51N1** := _____
(*When EGNDSW = Y, E51N1 := N*)

Neutral #2 Elements (N, 1, 2) **E51N2** := _____
(*When EGNDSW = Y, E51N2 := N*)

Ground #1 Elements (N, 1, 2) **E51G1** := _____

Ground #2 Elements (N, 1, 2) **E51G2** := _____

Negative-Sequence Elements (N, 1, 2) **E51Q** := _____

Date _____

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Other Enable Settings

Load Encroachment (Y, N)   **ELOAD**   := _____
  (*When VSELECT := OFF, ELOAD := N*; see *Figure 4.48*)

Directional Elements (Y, AUTO, AUTO2, N)   **E32**   := _____
  (*When VSELECT := OFF, E32 := N*;
  see *Figure 4.51–Figure 4.61*)

Voltage Elements (N, VY, VZ, BOTH)   **EVOLT**   := _____
  (see *Figure 4.26–Figure 4.29*)

Frequency Elements (N, 1–6)   **E81**   := _____
  (*When FSELECT := OFF, E81 := N*; see *Figure 4.38*)

Rate-of-Change-of-Frequency (N, 1–4)   **E81R**   := _____
  (*When FSELECT := OFF, E81R := N*; see *Figure 4.39*)

Fault Location (Y, N)   **EFLOC**   := _____
  (*When VSELECT = OFF, EFLOC := N*;
  see *Fault Location on page 12.8*)

Loss-of-Potential (Y, Y1, N)   **ELOP**   := _____
  (*When VSELECT = OFF, EFLOP := N*; see *Figure 4.50*)

Power Element Levels (N, 3P1–3P4)   **EPWR**   := _____
  (*When VSELECT = OFF, EPWR := N*;
  see *Power Elements on page 4.64*)

Synchronism Check (Y, N)   **E25**   := _____
  (*When FSELECT = OFF, E25 := N*;
  see *Figure 4.30* and *Figure 4.31*)

Reclosures (N, 1– 4)   **E79**   := _____
  (see *Reclosing Relay on page 6.17*)

Switch-Onto-Fault (Y, N)   **ESOTF**   := _____
  (see *Figure 5.7*)

Make EDDSOTF setting when setting ESOTF := Y.

Switch-Onto-Fault Disturbance Detector Supervision (Y, N)   **EDDSOTF**   := _____
  (*when ESOTF := N, EDDSOTF := N*; see *Figure 5.1*)

Demand Metering (THM = Thermal, ROL = Rolling)   **EDEM**   := _____
  (see *Figure 8.4*)

Voltage Sag/Swell/Interruption (Y, N)   **ESSI**   := _____
  (*when VSELECT := OFF, ESSI := N*;
  see *Figure 4.40*, *Figure 4.41*, and *Figure 4.42*)

High-Impedance Fault Detection (Y, N, T) (Ordering Option)   **EHIF**   := _____
  (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)

Second-Harmonic Blocking (Y, N)   **EHBL2**   := _____
  (see *Figure 4.25*)

Math Variable Settings (N, 1–64)   **EMV**   := _____
  (see *Analog Comparators and Checks on page 7.6*)

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Line Parameter Settings

See Line Impedance Conversions (Group Settings) on page 9.50 and Line Length (Group Setting) on page 9.49.

Make line parameter settings when Global setting VSELECT ≠ OFF.

Positive-Sequence Line Impedance Magnitude (0.50–2550.00 Ω secondary)	**Z1MAG**	:= _____
Positive-Sequence Line Impedance Angle (5.00–90.00 degrees)	**Z1ANG**	:= _____
Zero-Sequence Line Impedance Magnitude (0.50–2550.00 Ω secondary)	**Z0MAG**	:= _____
Zero-Sequence Line Impedance Angle (5.00–90.00 degrees)	**Z0ANG**	:= _____
Line Length (0.10–999.00, unitless)	**LL**	:= _____

Phase Instantaneous/Definite-Time Overcurrent Elements

See Figure 4.1 and Figure 4.2.

Number of phase element pickup settings dependent on preceding enable setting E50P := 1-6.

Pickup (OFF, 0.05–20.00 A)	**50P1P**	:= _____
	50P2P	:= _____
	50P3P	:= _____
	50P4P	:= _____
	50P5P	:= _____
	50P6P	:= _____

Phase Definite-Time Overcurrent Elements

See Figure 4.3–Figure 4.6.

Number of phase element time delay settings dependent on preceding enable setting E50P = 1-6; all four time delay settings are enabled if E50P ≥ 4.

Time Delay (0.00–16000.00 cycles in 0.25-cycle steps)	**50P1D**	:= _____
	50P2D	:= _____
	50P3D	:= _____
	50P4D	:= _____

Phase Definite-Time Overcurrent Element Torque-Control SELᴏɢɪᴄ Equations

See Figure 4.3–Figure 4.6.

Number of levels of phase element torque-control settings dependent on preceding enable setting E50P := 1-6; all four levels of torque-control settings are enabled if E50P > 4.

Torque-control equations cannot be set directly to logical 0 or NA.

Level 1—Maximum Phase

50P1TC := _____

Level 1—A-Phase

50A1TC := _____

Level 1—B-Phase

50B1TC := _____

Date _____

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Level 1—C-Phase

50C1TC := _____

Level 2—Maximum Phase

50P2TC := _____

Level 2—A-Phase

50A2TC := _____

Level 2—B-Phase

50B2TC := _____

Level 2—C-Phase

50C2TC := _____

Level 3—Maximum Phase

50P3TC := _____

Level 3—A-Phase

50A3TC := _____

Level 3—B-Phase

50B3TC := _____

Level 3—C-Phase

50C3TC := _____

Level 4—Maximum Phase

50P4TC := _____

Level 4—A-Phase

50A4TC := _____

Level 4—B-Phase

50B4TC := _____

Level 4—C-Phase

50C4TC := _____

Neutral Instantaneous/Definite-Time Overcurrent Elements—Channel IN

See Figure 4.10 and Figure 4.11.

Number of neutral element pickup settings dependent on preceding enable setting E50N := 1–6.

Pickup (OFF, 0.005–2.500 A) **50N1P** := _____

50N2P := _____

50N3P := _____

50N4P := _____

50N5P := _____

50N6P := _____

Neutral Definite-Time Overcurrent Elements

See Figure 4.10.

Number of neutral element time delay settings dependent on preceding enable setting E50N := 1–6; all four time delay settings are enabled if E50N ≥ 4.

Time Delay (0.00–16000.00 cycles in 0.25-cycle steps)

50N1D	:=	_____
50N2D	:=	_____
50N3D	:=	_____
50N4D	:=	_____

Neutral Definite-Time Overcurrent Element Torque-Control SELᴏɢɪᴄ Equations

See Figure 4.10.

Number of neutral element torque-control settings dependent on preceding enable setting E50N := 1–6; all four torque-control settings are enabled if E50N > 4.

Torque-control equations cannot be set directly to logical 0 or NA.

Level 1
50N1TC := _____

Level 2
50N2TC := _____

Level 3
50N3TC := _____

Level 4
50N4TC := _____

Ground Instantaneous/Definite-Time Overcurrent Elements

See Figure 4.12 and Figure 4.13.

Number of ground element pickup settings dependent on preceding enable setting E50G := 1–6.

Pickup
OFF, 0.005–20.000 A
  on channel IN base (see Note), when Global setting
  EGNDSW := Y and relay setting CTR = CTRN

0.005 – [20 • (CTR/CTRN)] A
  on channel IN base, when Global setting EGNDSW := Y
  and relay setting CTR ≠ CTRN

0.010–20.000 A
  on IA, IB, IC base, when Global setting EGNDSW := N

50G1P	:=	_____
50G2P	:=	_____
50G3P	:=	_____
50G4P	:=	_____
50G5P	:=	_____
50G6P	:=	_____

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

Date _____

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Ground Definite-Time Overcurrent Elements

See Figure 4.12.

Number of ground element time delay settings dependent on preceding enable setting E50G := 1–6; all four time delay settings are enabled if E50G ≥ 4.

Time Delay (0.00–16000.00 cycles in 0.25-cycle steps)

50G1D	:= _____
50G2D	:= _____
50G3D	:= _____
50G4D	:= _____

Ground Definite-Time Overcurrent Element Torque-Control SELᴏɢɪᴄ Equations

See Figure 4.12.

Number of ground element torque-control settings dependent on preceding enable setting E50G := 1–6; all four torque-control settings are enabled if E50G > 4.

Torque-control equations cannot be set directly to logical 0 or NA.

Level 1
50G1TC   := _____

Level 2
50G2TC   := _____

Level 3
50G3TC   := _____

Level 4
50G4TC   := _____

Negative-Sequence Instantaneous/Definite-Time Overcurrent Elements

See Figure 4.14 and Figure 4.15.*

Number of negative-sequence element time delay settings dependent on preceding enable setting E50Q := 1–6.

* IMPORTANT: See Setting Negative-Sequence Time-Overcurrent Elements on page 4.105 for information.

Pickup (OFF, 0.05–20.00 A)

50Q1P	:= _____
50Q2P	:= _____
50Q3P	:= _____
50Q4P	:= _____
50Q5P	:= _____
50Q6P	:= _____

Negative-Sequence Definite-Time Overcurrent Elements

See Figure 4.14.*

Number of negative-sequence element time delay settings dependent on preceding enable setting E50Q := 1–6; all four time delay settings are enabled if E50Q ≥ 4.

* IMPORTANT: See Setting Negative-Sequence Time-Overcurrent Elements on page 4.105 for information.

Time Delay (0.00–16000.00 cycles in 0.25-cycle steps)

50Q1D	:= _____
50Q2D	:= _____
50Q3D	:= _____
50Q4D	:= _____

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Negative-Sequence Definite-Time Overcurrent Element Torque-Control SELᴏɢɪᴄ Equations

See Figure 4.14.

Number of negative-sequence element torque-control settings dependent on preceding enable setting E50Q := 1–6; all four torque-control settings are enabled if E50Q > 4.

Torque-control equations cannot be set directly to logical 0 or NA.

Level 1
50Q1TC := _____

Level 2
50Q2TC := _____

Level 3
50Q3TC := _____

Level 4
50Q4TC := _____

Maximum-Phase Time-Overcurrent Element J

See Figure 4.16.

Make the following settings if preceding enable setting E51P := 1 or 2.

Pickup (OFF, 0.05–3.20 A)   **51PJP** := _____

Curve (U1–U5, C1–C5, recloser curves)   **51PJC** := _____
   See *Figure 9.1–Figure 9.20*

Time-Dial   **51PJTD** := _____
   0.50–15.00 for curves U1–U5
   0.05–1.00 for curves C1–C5
   0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51PJRS** := _____
   Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51PJCT** := _____

Minimum Response (0.00–60.00 cycles)   **51PJMR** := _____

Maximum-Phase Time-Overcurrent Element K

See Figure 4.16.

Make the following settings if preceding enable setting E51P := 2.

Pickup (OFF, 0.05–3.20 A)   **51PKP** := _____

Curve (U1–U5, C1–C5, recloser curves)   **51PKC** := _____
   See *Figure 9.1–Figure 9.20*

Time-Dial   **51PKTD** := _____
   0.50–15.00 for curves U1–U5
   0.05–1.00 for curves C1–C5
   0.10–2.00 for recloser curves

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Electromechanical Reset (Y, N)   **51PKRS**   := _____
Applicable only to curves U1–U5, C1–C5

Constant time adder (0.00–60.00 cycles)   **51PKCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51PKMR**   := _____

Maximum-Phase Time-Overcurrent Element SELᴏɢɪᴄ Settings

See Figure 4.16.

Make 51PTC setting when preceding enable setting E51P := 1 or 2.

51P Torque Control (SELᴏɢɪᴄ Equation)
Cannot be set directly to logical 0 or NA

   51PTC   := _____

Make 51PSW setting when preceding enable setting E51P := 2.

51P J/K Selection (SELᴏɢɪᴄ Equation)
Cannot be set to NA

   51PSW   := _____

A-Phase Time-Overcurrent Element J

See Figure 4.17.

Make the following settings if preceding enable setting E51ABC := 1 or 2.

Pickup (OFF, 0.05–3.20 A)   **51AJP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51AJC**   := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51AJTD**   := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51AJRS**   := _____
Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51AJCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51AJMR**   := _____

A-Phase Time-Overcurrent Element K

See Figure 4.17.

Make the following settings if preceding enable setting E51ABC := 2.

Pickup (OFF, 0.05–3.20 A)   **51AKP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51AKC**   := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51AKTD**   := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N) *Applicable only to curves U1–U5, C1–C5*	**51AKRS**	:= _____
Constant time adder (0.00–60.00 cycles)	**51AKCT**	:= _____
Minimum Response (0.00–60.00 cycles)	**51AKMR**	:= _____

A-Phase Time-Overcurrent Element SELOGIC Settings

See Figure 4.17.

Make 51ATC setting when preceding enable setting E51ABC := 1 or 2.

51A Torque Control (SELOGIC Equation)
Cannot be set directly to logical 0 or NA

51ATC := _____

Make 51ASW setting when preceding enable setting E51ABC := 2.

51A J/K Selection (SELOGIC Equation)
Cannot be set to NA

51ASW := _____

B-Phase Time-Overcurrent Element J

See Figure 4.18.

Make the following settings if preceding enable setting E51ABC := 1 or 2.

Pickup (OFF, 0.05–3.20 A)	**51BJP**	:= _____
Curve (U1–U5, C1–C5, recloser curves) See *Figure 9.1–Figure 9.20*	**51BJC**	:= _____
Time-Dial 0.50–15.00 for curves U1–U5 0.05–1.00 for curves C1–C5 0.10–2.00 for recloser curves	**51BJTD**	:= _____
Electromechanical Reset (Y, N) *Applicable only to curves U1–U5, C1–C5*	**51BJRS**	:= _____
Constant Time Adder (0.00–60.00 cycles)	**51BJCT**	:= _____
Minimum Response (0.00–60.00 cycles)	**51BJMR**	:= _____

B-Phase Time-Overcurrent Element K

See Figure 4.18.

Make the following settings if preceding enable setting E51ABC := 2.

Pickup (OFF, 0.05–3.20 A)	**51BKP**	:= _____
Curve (U1–U5, C1–C5, recloser curves) See *Figure 9.1–Figure 9.20*	**51BKC**	:= _____
Time-Dial 0.50–15.00 for curves U1–U5 0.05–1.00 for curves C1–C5 0.10–2.00 for recloser curves	**51BKTD**	:= _____

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Electromechanical Reset (Y, N)   **51BKRS**   := _____
Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51BKCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51BKMR**   := _____

B-Phase Time-Overcurrent Element SELogic Settings

See Figure 4.18.

Make 51BTC setting when preceding enable setting E51ABC := 1 or 2.

51B Torque Control (SELogic Equation)
Cannot be set directly to logical 0 or NA

    51BTC   := _____

Make 51BSW setting when preceding enable setting E51ABC := 2.

51B J/K Selection (SELogic Equation)
Cannot be set to NA

    51BSW   := _____

C-Phase Time-Overcurrent Element J

See Figure 4.19.

Make the following settings if preceding enable setting E51ABC := 1 or 2.

Pickup (OFF, 0.05–3.20 A)   **51CJP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51CJC**   := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51CJTD**   := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51CJRS**   := _____
Applicable only to curves U1–U5, C1–C5

Constant time adder (0.00–60.00 cycles)   **51CJCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51CJMR**   := _____

C-Phase Time-Overcurrent Element K

See Figure 4.19.

Make the following settings if preceding enable setting E51ABC := 2.

Pickup (OFF, 0.05–3.20 A)   **51CKP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51CKC**   := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51CKTD**   := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51CKRS**   := _____
Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51CKCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51CKMR**   := _____

C-Phase Time-Overcurrent Element SELOGIC Settings

See Figure 4.19.

Make 51CPTC setting when preceding enable setting E51ABC := 1 or 2.

51C Torque Control (SELOGIC Equation)
Cannot be set directly to logical 0 or NA

    51CTC   := _____

Make 51CSW setting when preceding enable setting E51ABC := 2.

51C J/K Selection (SELOGIC Equation)
Cannot be set to NA

    51CSW   := _____

Neutral Time-Overcurrent Element #1–J

See Figure 4.20.

Make the following settings if preceding enable setting E51N1 := 1 or 2.

Pickup (OFF, 0.005–0.64 A)   **51N1JP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51N1JC**   := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51N1JTD**   := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51N1JRS**   := _____
Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51N1JCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51N1JMR**   := _____

Neutral Time-Overcurrent Element #1–K

See Figure 4.20.

Make the following settings if preceding enable setting E51N1 := 2.

Pickup (OFF, 0.005–0.64 A)   **51N1KP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51N1KC**   := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51N1KTD**   := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51N1KRS**   := _____
Applicable only to curves U1–U5, C1–C5

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Constant Time Adder (0.00–60.00 cycles)   **51N1KCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51N1KMR**   := _____

Neutral Time-Overcurrent Element #1 SEL_{OGIC} Settings

See Figure 4.20.

Make 51N1TC setting when preceding enable setting E51N1 := 1 or 2.

51N1 Torque Control (SEL_{OGIC} Equation)
Cannot be set directly to logical 0 or NA

51N1TC   := _____

Make 51N1SW setting when preceding enable setting E51N1 := 2.

51N1 J/K Selection (SEL_{OGIC} Equation)
Cannot be set to NA

51N1SW   := _____

Neutral Time-Overcurrent Element #2-J

See Figure 4.21.

Make the following settings if preceding enable setting E51N2 := 1 or 2.

Pickup (OFF, 0.005–0.64 A)   **51N2JP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51N2JC**   := _____
  See *Figure 9.1–Figure 9.20*

Time-Dial   **51N2JTD**   := _____
  0.50–15.00 for curves U1–U5
  0.05–1.00 for curves C1–C5
  0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51N2JRS**   := _____
  Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51N2JCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51N2JMR**   := _____

Neutral Time-Overcurrent Element #2-K

See Figure 4.21.

Make the following settings if preceding enable setting E51N2 := 2.

Pickup (OFF, 0.005–0.64 A)   **51N2KP**   := _____

Curve (U1–U5, C1–C5, recloser curves)   **51N2KC**   := _____
  See *Figure 9.1–Figure 9.20*

Time-Dial   **51N2KTD**   := _____
  0.50–15.00 for curves U1–U5
  0.05–1.00 for curves C1–C5
  0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51N2KRS**   := _____
  Applicable only to curves U1–U5, C1–C5

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Constant Time Adder (0.00–60.00 cycles)   **51N2KCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51N2KMR**   := _____

Neutral Time-Overcurrent Element #2 SELOGIC Settings

See Figure 4.21.

Make 51N2TC setting when preceding enable setting E51N2 := 1 or 2.

51N2 Torque Control (SELOGIC Equation)
Cannot be set directly to logical 0 or NA

   51N2TC   := _____

Make 51N2SW setting when preceding enable setting E51N2 := 2.

51N2 J/K Selection (SELOGIC Equation)
Cannot be set to NA

   51N2SW   := _____

Ground Time-Overcurrent Element #1–J

See Figure 4.22.

Make the following settings if preceding enable setting E51G1 := 1 or 2.

Pickup   **51G1JP**   := _____

   OFF, 0.005–3.200 A
     on channel IN base (see Note), when Global setting
     EGNDSW := Y and relay setting CTR = CTRN

   OFF, 0.005–[3.2 • (CTR/CTRN)] A
     on channel IN base, when Global setting EGNDSW := Y
     and relay setting CTR ≠ CTRN

   OFF, 0.020–3.200 A
     on IA, IB, IC base, when Global setting EGNDSW := N

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

Curve (U1–U5, C1–C5, recloser curves)   **51G1JC**   := _____
   See *Figure 9.1–Figure 9.20*

Time-Dial   **51G1JTD**   := _____
   0.50–15.00 for curves U1–U5
   0.05–1.00 for curves C1–C5
   0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51G1JRS**   := _____
   Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51G1JCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51G1JMR**   := _____

Date _____

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Ground Time-Overcurrent Element #1–K

See Figure 4.22.

Make the following settings if preceding enable setting E51G1 := 2.

Pickup   **51G1KP**   := _____

OFF, 0.005–3.200 A
   on channel IN base (see Note), when Global setting
   EGNDSW := Y and relay setting CTR = CTRN

OFF, 0.005–[3.2 • (CTR/CTRN)] A
   on channel IN base, when Global setting EGNDSW := Y
   and relay setting CTR ≠ CTRN

OFF, 0.020–3.200 A
   on IA, IB, IC base, when Global setting EGNDSW := N

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

Curve (U1–U5, C1–C5, recloser curves)   **51G1KC**   := _____
   See *Figure 9.1–Figure 9.20*

Time-Dial   **51G1KTD**   := _____
   0.50–15.00 for curves U1–U5
   0.05–1.00 for curves C1–C5
   0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51G1KRS**   := _____
   Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51G1KCT**   := _____

Minimum Response (0.00–60.00 cycles)   **51G1KMR**   := _____

Ground Time-Overcurrent Element #1 SEL<small>OGIC</small> Settings

See Figure 4.22.

Make 51G1TC setting when preceding enable setting E51G1 := 1 or 2.

51G1 Torque Control (SEL<small>OGIC</small> Equation)
   Cannot be set directly to logical 0 or NA

   51G1TC   := _____

Make 51G1SW setting when preceding enable setting E51G1 := 2.

51G1 J/K Selection (SEL<small>OGIC</small> Equation)
   Cannot be set to NA

   51G1SW   := _____

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Ground Time-Overcurrent Element #2–J

See Figure 4.23.

Make the following settings if preceding enable setting E51G2 := 1 or 2.

Pickup   **51G2JP** := _____

 OFF, 0.005–3.200 A
  on channel IN base (see Note), when Global setting
  EGNDSW := Y and relay setting CTR = CTRN

 OFF, 0.005 – [3.2 • (CTR/CTRN)] A
  on channel IN base, when Global setting EGNDSW := Y
  and relay setting CTR ≠ CTRN

 OFF, 0.020–3.200 A
  on IA, IB, IC base, when Global setting EGNDSW := N

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

Curve (U1–U5, C1–C5, recloser curves) **51G2JC** := _____
 See *Figure 9.1–Figure 9.20*

Time-Dial   **51G2JTD** := _____
 0.50–15.00 for curves U1–U5
 0.05–1.00 for curves C1–C5
 0.10–2.00 for recloser curves

Electromechanical Reset (Y, N) **51G2JRS** := _____
 Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles) **51G2JCT** := _____

Minimum Response (0.00–60.00 cycles) **51G2JMR** := _____

Ground Time-Overcurrent Element #2-K

See Figure 4.23.

Make the following settings if preceding enable setting E51G2 := 2.

Pickup   **51G2KP** := _____

 OFF, 0.005–3.200 A
  on channel IN base (see Note), when Global setting
  EGNDSW := Y and relay setting CTR = CTRN

 OFF, 0.005–[3.2 • (CTR/CTRN)] A
  on channel IN base, when Global setting EGNDSW := Y
  and relay setting CTR ≠ CTRN

 OFF, 0.020–3.200 A
  on IA, IB, IC base, when Global setting EGNDSW := N

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

Curve (U1–U5, C1–C5, recloser curves) **51G2KC** := _____
 See *Figure 9.1–Figure 9.20*

Time-Dial   **51G2KTD** := _____
 0.50–15.00 for curves U1–U5
 0.05–1.00 for curves C1–C5
 0.10–2.00 for recloser curves

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Electromechanical Reset (Y, N)   **51G2KRS** := _____
Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51G2KCT** := _____

Minimum Response (0.00–60.00 cycles)   **51G2KMR** := _____

Ground Time-Overcurrent Element #2 SEL ogic Settings

See Figure 4.23.

Make 51G2TC setting when preceding enable setting E51G2 := 1 or 2.

51G2 Torque Control (SEL ogic Equation)
Cannot be set directly to logical 0 or NA

51G2TC   := _____

Make 51G2SW setting when preceding enable setting E51G2 := 2.

51G2 J/K Selection (SEL ogic Equation)
Cannot be set to NA

51G2SW   := _____

Negative-Sequence Time-Overcurrent Element J

See Figure 4.24.[1]

Make the following settings if preceding enable setting E51Q := 1 or 2.

Pickup (OFF, 0.05–3.20 A)   **51QJP** := _____

Curve (U1–U5, C1–C5, recloser curves)   **51QJC** := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51QJTD** := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

Electromechanical Reset (Y, N)   **51QJRS** := _____
Applicable only to curves U1–U5, C1–C5

Constant Time Adder (0.00–60.00 cycles)   **51QJCT** := _____

Minimum Response (0.00–60.00 cycles)   **51QJMR** := _____

Negative-Sequence Time-Overcurrent Element K

See Figure 4.24.[1]

Make the following settings if preceding enable setting E51Q := 2.

Pickup (OFF, 0.05–3.20 A)   **51QKP** := _____

Curve (U1–U5, C1–C5, recloser curves)   **51QKC** := _____
See *Figure 9.1–Figure 9.20*

Time-Dial   **51QKTD** := _____
0.50–15.00 for curves U1–U5
0.05–1.00 for curves C1–C5
0.10–2.00 for recloser curves

[1] IMPORTANT: See Setting Negative-Sequence Time-Overcurrent Elements on page 4.105 for information on setting negative-sequence overcurrent elements.

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Electromechanical Reset (Y, N) *Applicable only to curves U1–U5, C1–C5*	**51QKRS**	:= _____
Constant Time Adder (0.00–60.00 cycles)	**51QKCT**	:= _____
Minimum Response (0.00–60.00 cycles)	**51QKMR**	:= _____

Negative-Sequence Time-Overcurrent SELᴏɢɪᴄ Settings

See Figure 4.24.

Make 51QTC setting when preceding enable setting E51Q := 1 or 2.

51Q Torque Control (SELᴏɢɪᴄ Equation)
Cannot be set directly to logical 0 or NA

   51QTC := _____

Make 51QSW setting when preceding enable setting E51Q := 2.

51Q J/K Selection (SELᴏɢɪᴄ Equation)
Cannot be set to NA

   51QSW := _____

Load-Encroachment Elements

See Figure 4.48.

Make the following settings if preceding enable setting ELOAD := Y.

Forward Load Impedance (0.50–640.00 Ω secondary) (see *Line Impedance Conversions (Group Settings) on page 9.50*)	**ZLF**	:= _____
Reverse Load Impedance (0.50–640.00 Ω secondary) (see *Line Impedance Conversions (Group Settings) on page 9.50*)	**ZLR**	:= _____
Positive Forward Load Angle (–90.00° to +90.00°)	**PLAF**	:= _____
Negative Forward Load Angle (–90.00° to +90.00°)	**NLAF**	:= _____
Positive Reverse Load Angle (+90.00° to +270.00°)	**PLAR**	:= _____
Negative Reverse Load Angle (+90.00° to +270.00°)	**NLAR**	:= _____

Directional Elements

See Figure 4.51–Figure 4.61.

Make the following settings if preceding enable setting E32 := Y, AUTO, or AUTO2.

Ground directional element priority (combination of Q and V, or OFF)	**ORDER**	:= _____
Three-phase threshold for phase directional element (0.10–2.00 A secondary) (*When ELOAD := Y, 50P32P is hidden*; see *Figure 4.60*)	**50P32P**	:= _____

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If E32 := AUTO or AUTO2, following settings Z2F, Z2R, 50QFP, 50QRP, a2 and k2 are made automatically–see Directional Control Settings on page 4.89.

Forward directional Z2 threshold **Z2F** := _____
(–640.00 to +640.00 Ω secondary)

Reverse directional Z2 threshold **Z2R** := _____
(–640.00 to +640.00 Ω secondary)

Forward directional negative-sequence current pickup **50QFP** := _____
(0.05–1.00 A secondary)

Reverse directional negative-sequence current pickup **50QRP** := _____
(0.05–1.00 A secondary)

Positive-sequence current restraint factor, I_2/I_1 **a2** := _____
(0.02–0.50, unitless)

Zero-sequence current restraint factor, I_2/I_0 **k2** := _____
(0.10–1.20, unitless)

If setting ORDER does not contain V, then following settings 50GFP, 50GRP, a0G, Z0F, Z0R, Z0MTA, and E32IV are hidden. If E32 := AUTO or AUTO2, then following settings 50GFP, 50GRP, a0G, Z0F, Z0R, and Z0MTA are made automatically–see Directional Control Settings on page 4.89.

Forward directional ground current pickup **50GFP** := _____

Reverse directional ground current pickup **50GRP** := _____

0.005–1.00 A secondary
on channel IN base, when Global setting EGNDSW := Y
and group setting CTR = CTRN

0.005– [1.00 • (CTR/CTRN)] A secondary
on channel IN base, when Global setting EGNDSW := Y
and group setting CTR ≠ CTRN

0.010–1.00 A secondary
on IA, IB, IC base, when Global setting EGNDSW := N

Positive-sequence current restraint factor, I_0/I_1 **a0G** := _____
(0.001–0.500, unitless)

Forward directional Z0 threshold **Z0F** := _____
(–640.00 to +640.00 Ω secondary)

Reverse directional Z0 threshold **Z0R** := _____
(–640.00 to +640.00 Ω secondary)

Make setting Z0MTA if E32 := Y and ORDER contains V.

Zero-Sequence Maximum Torque Angle **Z0MTA** := _____
(–90.00 to –5.00 degrees and 5.00 to 90.00 degrees)

Enable for zero-sequence voltage-polarized directional **E32IV** := _____
elements (SELOGIC Equation)

VY-Terminal Voltage Elements

See Figure 4.26 and Figure 4.27.

Make the following settings if preceding enable setting EVOLT := VY or BOTH.

See Table 9.17 and accompanying text for proper VY-terminal voltage elements settings adjustments when LEA inputs are used.

Phase Undervoltage Pickup (OFF, 1.00–300.00 V secondary) **27YP1P** := _____

Phase Undervoltage Pickup (OFF, 1.00–300.00 V secondary) **27YP2P** := _____

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Phase-to-Phase Undervoltage Pickup
(OFF, 1.76–520.00 V secondary) **27YPP1P** := _____

Phase Overvoltage Pickup (OFF, 1.00–300.00 V secondary) **59YP1P** := _____

Phase Overvoltage (OFF, 1.00–300.00 V secondary) **59YP2P** := _____

Phase-to-Phase Overvoltage Pickup
(OFF, 1.76–520.00 V secondary) **59YPP1P** := _____

Zero-Sequence (3V0) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59YN1P** := _____

Zero-Sequence (3V0) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59YN2P** := _____

Negative-Sequence (V2) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59YQ1P** := _____

Positive-Sequence (V1) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59YV1P** := _____

VZ-Terminal Voltage Elements

See Figure 4.28 and Figure 4.29.

Make the following settings if preceding enable setting EVOLT := VZ or BOTH.

See Table 9.17 and accompanying text for proper VZ-terminal voltage elements settings adjustments when LEA inputs are used.

Phase Undervoltage Pickup (OFF, 1.00–300.00 V secondary) **27ZP1P** := _____

Phase Undervoltage Pickup (OFF, 1.00–300.00 V secondary) **27ZP2P** := _____

Phase-to-Phase Undervoltage Pickup
(OFF, 1.76–520.00 V secondary) **27ZPP1P** := _____

Phase Overvoltage Pickup (OFF, 1.00–300.00 V secondary) **59ZP1P** := _____

Phase Overvoltage (OFF, 1.00–300.00 V secondary) **59ZP2P** := _____

Phase-to-Phase Overvoltage Pickup
(OFF, 1.76–520.00 V secondary) **59ZPP1P** := _____

Zero-Sequence (3V0) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59ZN1P** := _____

Zero-Sequence (3V0) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59ZN2P** := _____

Negative-Sequence (V2) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59ZQ1P** := _____

Positive-Sequence (V1) Overvoltage Pickup
(OFF, 2.00–300.00 V secondary) **59ZV1P** := _____

Frequency Elements

See Figure 4.34–Figure 4.38.

Number of frequency element settings dependent on preceding enable setting E81 := 1–6.

Phase Undervoltage Block (12.50–300.00 V secondary) **27B81P** := _____

See Table 9.17 and accompanying text for possible 27B81P setting adjustment when LEA inputs are used.

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Level 1 Pickup (OFF, 40.00–65.00 Hz)	**81D1P**	:=
Level 1 Time Delay (2.00–16000.00 cycles in 0.25-cycle steps)	**81D1D**	:=
Level 2 Pickup (OFF, 40.00–65.00 Hz)	**81D2P**	:=
Level 2 Time Delay (2.00–16000.00 cycles in 0.25-cycle steps)	**81D2D**	:=
Level 3 Pickup (OFF, 40.00–65.00 Hz)	**81D3P**	:=
Level 3 Time Delay (2.00–16000.00 cycles in 0.25-cycle steps)	**81D3D**	:=
Level 4 Pickup (OFF, 40.00–65.00 Hz)	**81D4P**	:=
Level 4 Time Delay (2.00–16000.00 cycles in 0.25-cycle steps)	**81D4D**	:=
Level 5 Pickup (OFF, 40.00–65.00 Hz)	**81D5P**	:=
Level 5 Time Delay (2.00–16000.00 cycles in 0.25-cycle steps)	**81D5D**	:=
Level 6 Pickup (OFF, 40.00–65.00 Hz)	**81D6P**	:=
Level 6 Time Delay (2.00–16000.00 cycles in 0.25-cycle steps)	**81D6D**	:=

Rate-of-Change-of-Frequency Element Settings

See Figure 4.39.

Number of rate-of-change-of-frequency element settings dependent on preceding enable setting E81R := 1–4.

Level 1 Pickup (OFF, 0.10–15 Hz/second in 0.01 Hz/second steps)	**81R1P**	:=
Level 1 Trend (INC, DEC, ABS)	**81R1TRND**	:=
Level 1 Timer Pickup (0.10–60 seconds in 0.01 second steps)	**81R1PU**	:=
Level 1 Timer Dropout (0.00–60 seconds in 0.01 second steps)	**81R1DO**	:=
Level 2 Pickup (OFF, 0.10–15 Hz/second in 0.01 Hz/second steps)	**81R2P**	:=
Level 2 Trend (INC, DEC, ABS)	**81R2TRND**	:=
Level 2 Timer Pickup (0.10–60 seconds in 0.01 second steps)	**81R2PU**	:=
Level 2 Timer Dropout (0.00–60 seconds in 0.01 second steps)	**81R2DO**	:=
Level 3 Pickup (OFF, 0.10–15 Hz/second in 0.01 Hz/second steps)	**81R3P**	:=
Level 3 Trend (INC, DEC, ABS)	**81R3TRND**	:=
Level 3 Timer Pickup (0.10–60 seconds in 0.01 second steps)	**81R3PU**	:=
Level 3 Timer Dropout (0.00–60 seconds in 0.01 second steps)	**81R3DO**	:=
Level 4 Pickup (OFF, 0.10–15 Hz/second in 0.01 Hz/second steps)	**81R4P**	:=
Level 4 Trend (INC, DEC, ABS)	**81R4TRND**	:=
Level 4 Timer Pickup (0.10–60 seconds in 0.01 second steps)	**81R4PU**	:=

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Level 4 Timer Dropout (0.00–60 seconds in 0.01 second steps)   **81R4DO**   :=

Rate-of-Change-of-Frequency Torque Control   **81RTC**   :=
(SELOGIC control equation)

Power Elements

See Figure 4.44.

Number of power element settings dependent on preceding enable setting EPWR := 3P10–3P4.

See Table 9.17 and accompanying text for possible 3PWR1P, 3PWR2P, 3PWR3P, and 3PWR4P settings adjustments when LEA inputs are used.

Make settings 3PWR1P, PWR1T, and PWR1D if EPWR := 3P1–3P4.

Three-Phase Power Element Pickup   **3PWR1P**   :=
(OFF, 1.20–7800.00 VA secondary three-phase)

Power Element Type (+WATTS, –WATTS, +VARS, –VARS)   **PWR1T**   :=

Power Element Time Delay (0.00–16000.00 cycles)   **PWR1D**   :=

Make settings 3PWR2P, PWR2T, and PWR2D if EPWR := 3P2–3P4.

Three-Phase Power Element Pickup   **3PWR2P**   :=
(OFF, 1.20–7800.00 VA secondary three-phase)

Power Element Type (+WATTS, –WATTS, +VARS, –VARS)   **PWR2T**   :=

Power Element Time Delay (0.00–16000.00 cycles)   **PWR2D**   :=

Make settings 3PWR3P, PWR3T, and PWR3D if EPWR := 3P3–3P4.

Three-Phase Power Element Pickup   **3PWR3P**   :=
(OFF, 1.20–7800.00 VA secondary three-phase)

Power Element Type (+WATTS, –WATTS, +VARS, –VARS)   **PWR3T**   :=

Power Element Time Delay (0.00–16000.00 cycles)   **PWR3D**   :=

Make settings 3PWR4P, PWR4T, and PWR4D if EPWR := 3P4.

Three-Phase Power Element Pickup   **3PWR4P**   :=
(OFF, 1.20–7800.00 VA secondary three-phase)

Power Element Type (+WATTS, –WATTS, +VARS, –VARS)   **PWR4T**   :=

Power Element Time Delay (0.00–16000.00 cycles)   **PWR4D**   :=

Synchronism-Check Elements

See Figure 4.30 and Figure 4.31.

Make the following settings if preceding enable setting E25 := Y.

VP Window—Low Threshold (12.50–300.00 V, secondary)   **25VPLO**   :=

VP Window—High Threshold (12.50–300.00 V, secondary)   **25VPHI**   :=

VS Window—Low Threshold (12.50–300.00 V, secondary)   **25VSLO**   :=

VS Window—High Threshold (12.50–300.00 V, secondary)   **25VSHI**   :=

See Table 9.17 and accompanying text for possible 25VPLO, 25VPHI, 25SLO, and 25VSHI settings adjustments when LEA inputs are used.

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Maximum Slip Frequency (0.005–0.500 Hz)	**25SF**	:=	_____
Maximum Angle 1 (0.00°–80.00°)	**25ANG1**	:=	_____
Maximum Angle 2 (0.00°–80.00°)	**25ANG2**	:=	_____
Synchronizing Phase VS (0°–330° lagging VP, in 30° steps)	**SYNCP**	:=	_____

Breaker close time for angle compensation
  0.00–60.00 cycles in 0.25-cycle steps when NFREQ = 60;
  0.00–50.00 cycles in 0.25-cycle steps when NFREQ = 50   **TCLOSD** := _____

Block Synchronism-Check SELOGIC Equation

    BSYNCH   := _____

Reclosing Relay

See Table 6.6 and Table 6.7.

Number of recloser open interval timer settings dependent on preceding enable setting E79 := 1-4.

Open Interval 1 Time (OFF, 12.00–999999.00 cycles in 0.25-cycle steps)	**79OI1**	:=	_____
Open Interval 2 Time (OFF, 90.00–999999.00 cycles in 0.25-cycle steps)	**79OI2**	:=	_____
Open Interval 3 Time (OFF, 120.00–999999.00 cycles in 0.25-cycle steps)	**79OI3**	:=	_____
Open Interval 4 Time (OFF, 120.00–999999.00 cycles in 0.25-cycle steps)	**79OI4**	:=	_____
Reset Time From Reclose Cycle (180.00–999999.00 cycles in 0.25-cycle steps)	**79RSD**	:=	_____
Reset Time From Lockout (0.00–999999.00 cycles in 0.25-cycle steps)	**79RSLD**	:=	_____
Reclose Supervision Time Limit (OFF, 0.00–999999.00 cycles in 0.25-cycle steps)	**79CLSD**	:=	_____

Reclosing Relay SELOGIC Equations

See Reclosing Relay on page 6.17.

Make the following two settings if E79 := 1-4 **and** ESPB := N.

Reclose Initiate

    79RI3P   := _____

Reclose Initiate Supervision

    79RIS3P   := _____

Make the following two settings if E79 := 1-4.

Drive-to-Lockout

    79DTL3P   := _____

Drive-to-Lockout—Extra Equation

    79DTL3X   := _____

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Make the following six settings if E79 := 1–4 **and** ESPB := N.

Drive-to-Last Shot

79DLS3P   := _____

Skip Shot

79SKP3P   := _____

Stall Open Interval Timing

79STL3P   := _____

Block Reset Timing

79BRS3P   := _____

Sequence Coordination

79SEQ3P   := _____

Reclose Supervision

79CLS3P   := _____

Make the following settings if E79 := 1–4 **and** ESPB := Y.

Reclose Initiate

79RIA   := _____

Reclose Initiate Supervision

79RISA   := _____

Drive-to-Lockout

79DTLA   := _____

Drive-to-Last Shot

79DLSA   := _____

Skip Shot

79SKPA   := _____

Stall Open Interval Timing

79STLA   := _____

Block Reset Timing

79BRSA   := _____

Sequence Coordination

79SEQA   := _____

Reclose Supervision

79CLSA   := _____

Reclose Initiate

79RIB   := _____

Reclose Initiate Supervision

79RISB   := _____

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Drive-to-Lockout

79DTLB := _____

Drive-to-Last Shot

79DLSB := _____

Skip Shot

79SKPB := _____

Stall Open Interval Timing

79STLB := _____

Block Reset Timing

79BRSB := _____

Sequence Coordination

79SEQB := _____

Reclose Supervision

79CLSB := _____

Reclose Initiate

79RIC := _____

Reclose Initiate Supervision

79RISC := _____

Drive-to-Lockout

79DTLC := _____

Drive-to-Last Shot

79DLSC := _____

Skip Shot

79SKPC := _____

Stall Open Interval Timing

79STLC := _____

Block Reset Timing

79BRSC := _____

Sequence Coordination

79SEQC := _____

Reclose Supervision

79CLSC := _____

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Switch-Onto-Fault

See Figure 5.7.

Make the following settings if preceding enable setting ESOTF := Y.

Close Enable Time Delay
(OFF, 0.00–16000.00 cycles in 0.25-cycle steps)
CLOEND := _____

52A Enable Time Delay
(OFF, 0.00–16000.00 cycles in 0.25-cycle steps)
52AEND := _____

SOTF Duration (0.50–16000.00 cycles in 0.25-cycle steps)
SOTFD := _____

Close Signal Monitor SELOGIC Equation

CLMON := _____

Pole-Open Settings

See Pole Open Logic on page 5.9.

Make SPOD setting when setting ESPB := Y.

Single-Pole Open Time Delay (0.00–60.00 cycles)
SPOD := _____

Three-Pole Open Time Delay
(0.00–60.00 cycles in 0.25-cycle steps)
3POD := _____

Load Detection Phase Pickup (OFF, 0.05–1.00 A)
50LP := _____

Demand Metering Settings

See Figure 8.4.

Make the following settings, whether preceding enable setting EDEM := THM or ROL.

Time Constant (5, 10, 15, 30, 60 minutes)
DMTC := _____

Phase Pickup (OFF, 0.10–3.20 A)
PDEMP := _____

Make setting NDEMP when Global setting EGNDSW := N.

Neutral Pickup—Channel IN (OFF, 0.005–0.640 A)
NDEMP := _____

Ground Pickup
GDEMP := _____

OFF, 0.005–3.200 A
on channel IN base (see Note), when Global setting
EGNDSW := Y and relay setting CTR = CTRN

OFF, 0.005–[3.2 • (CTR/CTRN)] A
on channel IN base, when Global setting EGNDSW := Y
and relay setting CTR ≠ CTRN

OFF, 0.020–3.200 A
on IA, IB, IC base, when Global setting EGNDSW := N

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base
and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the
factory-default wiring includes a wired residual connection to the IN channel.

Negative-Sequence Pickup (OFF, 0.10–3.20 A)
QDEMP := _____

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Voltage Sag/Swell/Interrupt

See Figure 4.40–Figure 4.42.

Make the following settings if preceding enable setting ESSI := Y.

Percent Phase Interruption Pickup (OFF, 5.00–95.00)   **VINT**   := _____
   (Cannot be set higher than VSAG)

Percent Phase Voltage Sag Pickup (OFF, 10.00–95.00)   **VSAG**   := _____

Percent Phase Voltage Swell Pickup (OFF, 105.00–180.00)   **VSWELL**   := _____

SSI Trigger SELOGIC Equation
   SSI_TRIG := _____

High-Impedance Fault Detection (Arc Sense Technology) Settings

Ordering Option.

See High-Impedance Fault Detection (Arc Sense Technology) on page 4.111.

Make the following settings if preceding enable setting EHIF := Y or T.

HIF Detection Sensitivity SELOGIC Equation
   HIFMODE := _____

Freeze HIF Detection Algorithm SELOGIC Equation
   HIFFRZ   := _____

Begin Initial HIF Detection Tuning Process SELOGIC Equation
   HIFITUNE := _____

50G High-Impedance (HIZ) Fault Detection Settings

(Ordering Option)

See 50G High-Impedance (HIZ) Fault Detection on page 4.116.

Pickup   **50GHIZP** := _____

OFF, 0.005–20.000 A
   on channel IN base (see Note), when Global setting
   EGNDSW := Y and relay setting CTR = CTRN
   0.005 – [20 • (CTR/CTRN)] A
   on channel IN base, when Global setting EGNDSW := Y and
   relay setting CTR ≠ CTRN
   0.010–20.000 A
   on IA, IB, IC base, when Global setting EGNDSW := N

NOTE: In the case where EGNDSW := Y and CTR = CTRN, there is no difference between the IN current base and the IA, IB, IC current base. This is the standard configuration for the SEL-651R-2, because the factory-default wiring includes a wired residual connection to the IN channel.

50G HIZ Element Pickup/Dropout Counts (1–1000)   **NPUDO** := _____

NPUDO Time Window (0.01–20 seconds)   **TPUDO** := _____

HIZ Counts [1 HIZ Count = NPUDO counts] (1–1000)   **NHIZ**   := _____

NHIZ Time Window (1–200 seconds)   **THIZ**   := _____

HIZ Counts Reporting Threshold (1–1000)   **NHIZR** := _____

HIZ Alarm Reset SELOGIC Equation   **HIZRST** := _____

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Second-Harmonic Blocking

See Second-Harmonic Blocking Logic on page 4.28.

Make the following settings if EHBL2 := Y:

Second-Harmonic Pickup (5–100% in 1% steps)	**HBL2P**	:= _____
Second-Harmonic Pickup Delay (0.00–16000 cycles in 0.25 cycle steps)	**HBL2PU**	:= _____
Second-Harmonic Dropout Delay (0.00–16000 cycles in 0.25 cycle steps)	**HBL2DO**	:= _____

Second-Harmonic Blocking Torque Control SELOGIC Equation

HBL2TC := _____

Math Variable Settings

See Analog Comparators and Checks on page 7.6.

Number of math variable settings dependent on preceding enable setting EMV := 1-64.

Math Variable (−16000.00 to +16000.00)

MV01	:= _____
MV02	:= _____
MV03	:= _____
MV04	:= _____
MV05	:= _____
MV06	:= _____
MV07	:= _____
MV08	:= _____
MV09	:= _____
MV10	:= _____
MV11	:= _____
MV12	:= _____
MV13	:= _____
MV14	:= _____
MV15	:= _____
MV16	:= _____
MV17	:= _____
MV18	:= _____
MV19	:= _____
MV20	:= _____
MV21	:= _____
MV22	:= _____
MV23	:= _____
MV24	:= _____
MV25	:= _____
MV26	:= _____
MV27	:= _____
MV28	:= _____
MV29	:= _____
MV30	:= _____
MV31	:= _____
MV32	:= _____

Date _____

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MV33	:=	_____
MV34	:=	_____
MV35	:=	_____
MV36	:=	_____
MV37	:=	_____
MV38	:=	_____
MV39	:=	_____
MV40	:=	_____
MV41	:=	_____
MV42	:=	_____
MV43	:=	_____
MV44	:=	_____
MV45	:=	_____
MV46	:=	_____
MV47	:=	_____
MV48	:=	_____
MV49	:=	_____
MV50	:=	_____
MV51	:=	_____
MV52	:=	_____
MV53	:=	_____
MV54	:=	_____
MV55	:=	_____
MV56	:=	_____
MV57	:=	_____
MV58	:=	_____
MV59	:=	_____
MV60	:=	_____
MV61	:=	_____
MV62	:=	_____
MV63	:=	_____
MV64	:=	_____

Trip Logic Settings

See Figure 5.1 and Figure 5.4.

Minimum trip duration time   **TDURD**   := _____
(4.00–16000.00 cycles in 0.25-cycle steps)

Trip Logic SELᴏɢɪᴄ Settings

See Figure 5.1.

Three-Phase Trip Conditions
TR3P   := _____

Three-Phase Trip Conditions—Extra Equation
TR3X   := _____

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Three-Phase Trip Conditions—qualified by disturbance
detector logic (see *Figure 5.3*)

 TRQL3P   := _____

Make settings TRA, TRQLA, TRB, TRQLB, TRC, and TRQLC when setting ESPB := Y.

A-Phase Trip Conditions

 TRA   := _____

A-Phase Trip Conditions—qualified by disturbance detector
logic (see *Figure 5.3*)

 TRQLA   := _____

B-Phase Trip Conditions

 TRB   := _____

B-Phase Trip Conditions—qualified by disturbance detector
logic (see *Figure 5.3*)

 TRQLB   := _____

C-phase trip conditions

 TRC   := _____

C-Phase Trip Conditions—qualified by disturbance detector
logic (see *Figure 5.3*)

 TRQLC   := _____

Make setting TRSOTF when setting ESOTF := Y.

Switch-Onto-Fault Trip Conditions

 TRSOTF   := _____

Make setting ULTR3P when setting ESPB := N.

Unlatch Trip Conditions

 ULTR3P   := _____

Close Logic Settings

See Figure 6.1 and Figure 6.3.

Close Failure Time Delay (OFF, 0.00–16000.00 cycles)   **CFD**   := _____

Close Logic SELᴏɢɪᴄ Settings

See Figure 6.1, Figure 6.2, and Figure 6.3.

Make setting 52A_3P when Global setting BKTYP := 3.

Three-Phase Circuit Breaker Status *(Cannot be set to NA)*

 52A_3P   := _____

Make settings 52A_A, 52A_B, 52A_C when Global setting BKTYP := 1.

A-Phase Circuit Breaker Status *(Cannot be set to NA)*

 52A_A   := _____

B-Phase Circuit Breaker Status *(Cannot be set to NA)*

 52A_B   := _____

Date _____

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C-Phase Circuit Breaker Status *(Cannot be set to NA)*

   52A_C   :=   _____

Make setting CL3P when setting ESPB := N.

   Three-Phase Close Conditions

   CL3P   :=   _____

Make settings CLA, CLB, CLC when setting ESPB := Y.

   A-Phase Close Conditions

   CLA   :=   _____

   B-Phase Close Conditions

   CLB   :=   _____

   C-Phase Close Conditions

   CLC   :=   _____

Make setting ULCL3P when setting ESPB := N.

   Three-Phase Unlatch Close Conditions

   ULCL3P   :=   _____

Make settings ULCLA, ULCLB, ULCLC when setting ESPB := Y.

   A-Phase Unlatch Close Conditions

   ULCLA   :=   _____

   B-Phase Unlatch Close Conditions

   ULCLB   :=   _____

   C-Phase Unlatch Close Conditions

   ULCLC   :=   _____

Recloser Interface Trip and Close Settings

See Trip and Close Mapping and Output Logic on page 7.31.

   Pole 1 Trip Mapping SELOGIC Equation

   RCTR1   :=   _____

Make RCTR2 and RCTR3 settings when a single-phase recloser interface is ordered.

   Pole 2 Trip Mapping SELOGIC Equation

   RCTR2   :=   _____

   Pole 3 Trip Mapping SELOGIC Equation

   RCTR3   :=   _____

   Pole 1 Close Mapping SELOGIC Equation

   RCCL1   :=   _____

Make RCCL2 and RCCL3 settings when a single-phase recloser interface is ordered.

   Pole 2 Close Mapping SELOGIC Equation

   RCCL2   :=   _____

   Pole 3 Close Mapping SELOGIC Equation

   RCCL3   :=   _____

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(Serial Port Command SET L n, [where n = group 1–8; defaults to active group])

SELᴏɢɪᴄ Enable Settings

See Enable Settings on page 9.57.

SELᴏɢɪᴄ Latches (N, 1–32)   **ELAT**   := _____

SELᴏɢɪᴄ Variables/Timers (N, 1–64)   **ESV**   := _____

SELᴏɢɪᴄ Counters (N, 1–16)   **ESC**   := _____

Latch Bits Set/Reset SELᴏɢɪᴄ Equations

See Figure 7.6.

Number of latch bit set/reset settings dependent on preceding enable setting ELAT := 1–32.

Set Latch Bit LT01
     SET01   := _____

Reset Latch Bit LT01
     RST01   := _____

Set Latch Bit LT02
     SET02   := _____

Reset Latch Bit LT02
     RST02   := _____

Set Latch Bit LT03
     SET03   := _____

Reset Latch Bit LT03
     RST03   := _____

Set Latch Bit LT04
     SET04   := _____

Reset Latch Bit LT04
     RST04   := _____

Set Latch Bit LT05
     SET05   := _____

Reset Latch Bit LT05
     RST05   := _____

Set Latch Bit LT06
     SET06   := _____

Reset Latch Bit LT06
     RST06   := _____

Date _____

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Set Latch Bit LT07
SET07 := _____

Reset Latch Bit LT07
RST07 := _____

Set Latch Bit LT08
SET08 := _____

Reset Latch Bit LT08
RST08 := _____

Set Latch Bit LT09
SET09 := _____

Reset Latch Bit LT09
RST09 := _____

Set Latch Bit LT10
SET10 := _____

Reset Latch Bit LT10
RST10 := _____

Set Latch Bit LT11
SET11 := _____

Reset Latch Bit LT11
RST11 := _____

Set Latch Bit LT12
SET12 := _____

Reset Latch Bit LT12
RST12 := _____

Set Latch Bit LT13
SET13 := _____

Reset Latch Bit LT13
RST13 := _____

Set Latch Bit LT14
SET14 := _____

Reset Latch Bit LT14
RST14 := _____

Set Latch Bit LT15
SET15 := _____

Reset Latch Bit LT15
RST15 := _____

Set Latch Bit LT16

SET16 := _____

Reset Latch Bit LT16

RST16 := _____

Set Latch Bit LT17

SET17 := _____

Reset Latch Bit LT17

RST17 := _____

Set Latch Bit LT18

SET18 := _____

Reset Latch Bit LT18

RST18 := _____

Set Latch Bit LT19

SET19 := _____

Reset Latch Bit LT19

RST19 := _____

Set Latch Bit LT20

SET20 := _____

Reset Latch Bit LT20

RST20 := _____

Set Latch Bit LT21

SET21 := _____

Reset Latch Bit LT21

RST21 := _____

Set Latch Bit LT22

SET22 := _____

Reset Latch Bit LT22

RST22 := _____

Set Latch Bit LT23

SET23 := _____

Reset Latch Bit LT23

RST23 := _____

Set Latch Bit LT24

SET24 := _____

Reset Latch Bit LT24

RST24 := _____

Date _____

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Set Latch Bit LT25
SET25 := _____

Reset Latch Bit LT25
RST25 := _____

Set Latch Bit LT26
SET26 := _____

Reset Latch Bit LT26
RST26 := _____

Set Latch Bit LT27
SET27 := _____

Reset Latch Bit LT27
RST27 := _____

Set Latch Bit LT28
SET28 := _____

Reset Latch Bit LT28
RST28 := _____

Set Latch Bit LT29
SET29 := _____

Reset Latch Bit LT29
RST29 := _____

Set Latch Bit LT30
SET30 := _____

Reset Latch Bit LT30
RST30 := _____

Set Latch Bit LT31
SET31 := _____

Reset Latch Bit LT31
RST31 := _____

Set Latch Bit LT32
SET32 := _____

Reset Latch Bit LT32
RST32 := _____

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SELogic Variable/Timer Settings

See Figure 7.3.

Number of SELogic variables/timers settings dependent on preceding enable setting ESV := 1-64.

SV01 Timer Pickup (0.00–999999.00 cycles)   **SV01PU**   := _____

SV01 Timer Dropout (0.00–999999.00 cycles)   **SV01DO**   := _____

SV01 Input SELogic Equation

SV01   := _____

Pickup and dropout timers SV02–SV64 have the same setting range as SV01.

                                         SV02PU   := _____
                                         SV02DO   := _____

SV02   := _____

                                         SV03PU   := _____
                                         SV03DO   := _____

SV03   := _____

                                         SV04PU   := _____
                                         SV04DO   := _____

SV04   := _____

                                         SV05PU   := _____
                                         SV05DO   := _____

SV05   := _____

                                         SV06PU   := _____
                                         SV06DO   := _____

SV06   := _____

                                         SV07PU   := _____
                                         SV07DO   := _____

SV07   := _____

                                         SV08PU   := _____
                                         SV08DO   := _____

SV08   := _____

                                         SV09PU   := _____
                                         SV09DO   := _____

SV09   := _____

                                         SV10PU   := _____
                                         SV10DO   := _____

SV10   := _____

                                         SV11PU   := _____
                                         SV11DO   := _____

SV11   := _____

Date _____

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		SV12PU	:= _____
		SV12DO	:= _____

SV12 := _____

		SV13PU	:= _____
		SV13DO	:= _____

SV13 := _____

		SV14PU	:= _____
		SV14DO	:= _____

SV14 := _____

		SV15PU	:= _____
		SV15DO	:= _____

SV15 := _____

		SV16PU	:= _____
		SV16DO	:= _____

SV16 := _____

		SV17PU	:= _____
		SV17DO	:= _____

SV17 := _____

		SV18PU	:= _____
		SV18DO	:= _____

SV18 := _____

		SV19PU	:= _____
		SV19DO	:= _____

SV19 := _____

		SV20PU	:= _____
		SV20DO	:= _____

SV20 := _____

		SV21PU	:= _____
		SV21DO	:= _____

SV21 := _____

		SV22PU	:= _____
		SV22DO	:= _____

SV22 := _____

		SV23PU	:= _____
		SV23DO	:= _____

SV23 := _____

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		SV24PU	:= _____
		SV24DO	:= _____
SV24	:= _____		
		SV25PU	:= _____
		SV25DO	:= _____
SV25	:= _____		
		SV26PU	:= _____
		SV26DO	:= _____
SV26	:= _____		
		SV27PU	:= _____
		SV27DO	:= _____
SV27	:= _____		
		SV28PU	:= _____
		SV28DO	:= _____
SV28	:= _____		
		SV29PU	:= _____
		SV29DO	:= _____
SV29	:= _____		
		SV30PU	:= _____
		SV30DO	:= _____
SV30	:= _____		
		SV31PU	:= _____
		SV31DO	:= _____
SV31	:= _____		
		SV32PU	:= _____
		SV32DO	:= _____
SV32	:= _____		
		SV33PU	:= _____
		SV33DO	:= _____
SV33	:= _____		
		SV34PU	:= _____
		SV34DO	:= _____
SV34	:= _____		
		SV35PU	:= _____
		SV35DO	:= _____
SV35	:= _____		
		SV36PU	:= _____
		SV36DO	:= _____
SV36	:= _____		

Date _____

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			SV37PU	:= _____
			SV37DO	:= _____
SV37	:= _____			

			SV38PU	:= _____
			SV38DO	:= _____
SV38	:= _____			

			SV39PU	:= _____
			SV39DO	:= _____
SV39	:= _____			

			SV40PU	:= _____
			SV40DO	:= _____
SV40	:= _____			

			SV41PU	:= _____
			SV41DO	:= _____
SV41	:= _____			

			SV42PU	:= _____
			SV42DO	:= _____
SV42	:= _____			

			SV43PU	:= _____
			SV43DO	:= _____
SV43	:= _____			

			SV44PU	:= _____
			SV44DO	:= _____
SV44	:= _____			

			SV45PU	:= _____
			SV45DO	:= _____
SV45	:= _____			

			SV46PU	:= _____
			SV46DO	:= _____
SV46	:= _____			

			SV47PU	:= _____
			SV47DO	:= _____
SV47	:= _____			

			SV48PU	:= _____
			SV48DO	:= _____
SV48	:= _____			

			SV49PU	:= _____
			SV49DO	:= _____
SV49	:= _____			

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			SV50PU	:= _____
			SV50DO	:= _____

SV50 := _____

			SV51PU	:= _____
			SV51DO	:= _____

SV51 := _____

			SV52PU	:= _____
			SV52DO	:= _____

SV52 := _____

			SV53PU	:= _____
			SV53DO	:= _____

SV53 := _____

			SV54PU	:= _____
			SV54DO	:= _____

SV54 := _____

			SV55PU	:= _____
			SV55DO	:= _____

SV55 := _____

			SV56PU	:= _____
			SV56DO	:= _____

SV56 := _____

			SV57PU	:= _____
			SV57DO	:= _____

SV57 := _____

			SV58PU	:= _____
			SV58DO	:= _____

SV58 := _____

			SV59PU	:= _____
			SV59DO	:= _____

SV59 := _____

			SV60PU	:= _____
			SV60DO	:= _____

SV60 := _____

			SV61PU	:= _____
			SV61DO	:= _____

SV61 := _____

			SV62PU	:= _____
			SV62DO	:= _____

SV62 := _____

Date _____

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| | SV63PU | := _____ |
| | SV63DO | := _____ |

SV63 := _____

| | SV64PU | := _____ |
| | SV64DO | := _____ |

SV64 := _____

SEL<small>OGIC</small> Counter Settings

See Counters on page 7.13.

Number of SEL<small>OGIC</small> counter settings dependent on preceding enable setting ESC := 1–16)

NOTE: For any counter, if the last setting (e.g., SC12CD) is set to NA, the entire counter (SC12, in this example) is disabled and the counter value (if SC12 = 10, when setting SC12CD to NA, SC12 will be frozen at 10) will be frozen. If the count-down function is not needed for a particular counter application, set the count-down setting to logical 0 (e.g., SC12CD := 0) to allow the rest of the counter to function.

SC01 Preset Value, unitless (1–65000)   **SC01PV**   := _____

SC01 Reset Input SEL<small>OGIC</small> Equation

SC01R := _____

SC01 Load Input SEL<small>OGIC</small> Equation

SC01LD := _____

SC01 Count-Up Input SEL<small>OGIC</small> Equation

SC01CU := _____

SC01 Count-Down Input SEL<small>OGIC</small> Equation

SC01CD := _____

SC02 Preset Value, unitless (1–65000)   **SC02PV**   := _____

SC02 Reset Input SEL<small>OGIC</small> Equation

SC02R := _____

SC02 Load Input SEL<small>OGIC</small> Equation

SC02LD := _____

SC02 Count-Up Input SEL<small>OGIC</small> Equation

SC02CU := _____

SC02 Count-Down Input SEL<small>OGIC</small> Equation

SC02CD := _____

SC03 Preset Value, unitless (1–65000)   **SC03PV**   := _____

SC03 Reset Input SELOGIC Equation
   SC03R   := _____

SC03 Load Input SELOGIC Equation
   SC03LD   := _____

SC03 Count-Up Input SELOGIC Equation
   SC03CU   := _____

SC03 Count-Down Input SELOGIC Equation
   SC03CD   := _____

SC04 Preset Value, unitless (1–65000)   **SC04PV**   := _____

SC04 Reset Input SELOGIC Equation
   SC04R   := _____

SC04 Load Input SELOGIC Equation
   SC04LD   := _____

SC04 Count-Up Input SELOGIC Equation
   SC04CU   := _____

SC04 Count-Down Input SELOGIC Equation
   SC04CD   := _____

SC05 Preset Value, unitless (1–65000)   **SC05PV**   := _____

SC05 Reset Input SELOGIC Equation
   SC05R   := _____

SC05 Load Input SELOGIC Equation
   SC05LD   := _____

SC05 Count-Up Input SELOGIC Equation
   SC05CU   := _____

SC05 Count-Down Input SELOGIC Equation
   SC05CD   := _____

Date _____

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SC06 Preset Value, unitless (1–65000)   **SC06PV**   := _____

SC06 Reset Input SELOGIC Equation
  SC06R   := _____

SC06 Load Input SELOGIC Equation
  SC06LD   := _____

SC06 Count-Up Input SELOGIC Equation
  SC06CU   := _____

SC06 Count-Down Input SELOGIC Equation
  SC06CD   := _____

SC07 Preset Value, unitless (1–65000)   **SC07PV**   := _____

SC07 Reset Input SELOGIC Equation
  SC07R   := _____

SC07 Load Input SELOGIC Equation
  SC07LD   := _____

SC07 Count-Up Input SELOGIC Equation
  SC07CU   := _____

SC07 Count-Down Input SELOGIC Equation
  SC07CD   := _____

SC08 Preset Value, unitless (1–65000)   **SC08PV**   := _____

SC08 Reset Input SELOGIC Equation
  SC08R   := _____

SC08 Load Input SELOGIC Equation
  SC08LD   := _____

SC08 Count-Up Input SELOGIC Equation
  SC08CU   := _____

SC08 Count-Down Input SELOGIC Equation
  SC08CD   := _____

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SC09 Preset Value, unitless (1–65000) **SC09PV** := _____

SC09 Reset Input SELOGIC Equation

SC09R := _____

SC09 Load Input SELOGIC Equation

SC09LD := _____

SC09 Count-Up Input SELOGIC Equation

SC09CU := _____

SC09 Count-Down Input SELOGIC Equation

SC09CD := _____

SC10 Preset Value, unitless (1–65000) **SC10PV** := _____

SC10 Reset Input SELOGIC Equation

SC10R := _____

SC10 Load Input SELOGIC Equation

SC10LD := _____

SC10 Count-Up Input SELOGIC Equation

SC10CU := _____

SC10 Count-Down Input SELOGIC Equation

SC10CD := _____

SC11 Preset Value, unitless (1–65000) **SC11PV** := _____

SC11 Reset Input SELOGIC Equation

SC11R := _____

SC11 Load Input SELOGIC Equation

SC11LD := _____

SC11 Count-Up Input SELOGIC Equation

SC11CU := _____

SC11 Count-Down Input SELOGIC Equation

SC11CD := _____

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SC12 Preset Value, unitless (1–65000)   **SC12PV**   := _____

SC12 Reset Input SELOGIC Equation

SC12R   := _____

SC12 Load Input SELOGIC Equation

SC12LD   := _____

SC12 Count-Up Input SELOGIC Equation

SC12CU   := _____

SC12 Count-Down Input SELOGIC Equation

SC12CD   := _____

SC13 Preset Value, unitless (1–65000)   **SC13PV**   := _____

SC13 Reset Input SELOGIC Equation

SC13R   := _____

SC13 Load Input SELOGIC Equation

SC13LD   := _____

SC13 Count-Up Input SELOGIC Equation

SC13CU   := _____

SC13 Count-Down Input SELOGIC Equation

SC13CD   := _____

SC14 Preset Value, unitless (1–65000)   **SC14PV**   := _____

SC14 Reset Input SELOGIC Equation

SC14R   := _____

SC14 Load Input SELOGIC Equation

SC14LD   := _____

SC14 Count-Up Input SELOGIC Equation

SC14CU   := _____

SC14 Count-Down Input SELOGIC Equation

SC14CD   := _____

SC15 Preset Value, unitless (1–65000)   **SC15PV**   := _____

SC15 Reset Input SELOGIC Equation

SC15R   := _____

SC15 Load Input SELOGIC Equation

SC15LD   := _____

SC15 Count-Up Input SELOGIC Equation

SC15CU   := _____

SC15 Count-Down Input SELOGIC Equation

SC15CD   := _____

SC16 Preset Value, unitless (1–65000)   **SC16PV**   := _____

SC16 Reset Input SELOGIC Equation

SC16R   := _____

SC16 Load Input SELOGIC Equation

SC16LD   := _____

SC16 Count-Up Input SELOGIC Equation

SC16CU   := _____

SC16 Count-Down Input SELOGIC Equation

SC16CD   := _____

Output Contact SELOGIC Equations

See Output Contacts on page 7.34.

Make setting OUT101–OUT108 if extra I/O is ordered.

NOTE: Output Contact Equations cannot be set to NA.

Output Contact OUT101

OUT101   := _____

Output Contact OUT102

OUT102   := _____

Output Contact OUT103

OUT103   := _____

Output Contact OUT104

OUT104   := _____

Output Contact OUT105

OUT105   := _____

Output Contact OUT106

OUT106   := _____

Date _____

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Output Contact OUT107
OUT107   :=   _____

Output Contact OUT108
OUT108   :=   _____

Output Contact OUT201
OUT201   :=   _____

Output Contact OUT202
OUT202   :=   _____

MIRRORED BITS Transmit SELOGIC Equations

See Appendix D: MIRRORED BITS Communications.

Channel A, Transmit Bit 1
TMB1A   :=   _____

Channel A, Transmit Bit 2
TMB2A   :=   _____

Channel A, Transmit Bit 3
TMB3A   :=   _____

Channel A, Transmit Bit 4
TMB4A   :=   _____

Channel A, Transmit Bit 5
TMB5A   :=   _____

Channel A, Transmit Bit 6
TMB6A   :=   _____

Channel A, Transmit Bit 7
TMB7A   :=   _____

Channel A, Transmit Bit 8
TMB8A   :=   _____

Channel B, Transmit Bit 1
TMB1B   :=   _____

Channel B, Transmit Bit 2
TMB2B   :=   _____

Channel B, Transmit Bit 3
TMB3B   :=   _____

Channel B, Transmit Bit 4
TMB4B   :=   _____

Channel B, Transmit Bit 5
TMB5B   :=   _____

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Channel B, Transmit Bit 6
TMB6B := _____

Channel B, Transmit Bit 7
TMB7B := _____

Channel B, Transmit Bit 8
TMB8B := _____

Phasor Measurement Unit (PMU) Trigger Equations

See Appendix J.

PMU Trigger
PMTRIG := _____

Trigger Reason Bit 1
TREA1 := _____

Trigger Reason Bit 2
TREA2 := _____

Trigger Reason Bit 3
TREA3 := _____

Trigger Reason Bit 4
TREA4 := _____

Front-Panel Settings

(Serial Port Command SET F Set/Show Front-Panel Menu*)

   * SELOGIC control equations can be viewed, but not changed, via the front-panel set/show front-panel menu.

General Settings

See Enable Settings on page 9.57.

| Enable Display Points (N, 1–32) | **EDP** | := _____ |
| Enable Local Bits (N, 1–16) | **ELB** | := _____ |

See Human-Machine Interface on page 11.2.

Front-Panel Time-Out (OFF, 1–30min)	**FP_TO**	:= _____
Display Update Rate (1–60 sec)	**SCROLD**	:= _____
Front-Panel Contrast (1–16)	**FP_CONT**	:= _____

See Rotating Display on page 11.13.

Front-Panel Neutral/Ground Display (OFF, IN, IG)	**FPNGD**	:= _____
Front-Panel VY-Terminal Voltage Display (OFF, ON)	**FPVYD**	:= _____
Front-Panel VZ-Terminal Voltage Display (OFF, ON)	**FPVZD**	:= _____

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See Status and Trip Target LEDs on page 11.19.

ENABLED LED Asserted Color (R, G, A)[1]   **LEDENAC**   := _____

Make setting LEDTRAC if Tricolor LED option is ordered.

TRIP LED Asserted Color (R, G, A)[1]   **LEDTRAC**   := _____

See Figure 5.10.

Reset Trip-Latched LEDs On Close (Y, N)   **RSTLED**   := _____

NOTE 1: Asserted color choices: R=Red, G=Green, A=Amber

Operator Control LED Settings

See Figure 11.15.

PB01 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB01LEDC**   := _____

  PB01 LED SELOGIC Equation
PB01_LED   := _____

PB02 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB02LEDC**   := _____

  PB02 LED SELOGIC Equation
PB02_LED   := _____

PB03 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB03LEDC**   := _____

  PB03 LED SELOGIC Equation
PB03_LED   := _____

PB04 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB04LEDC**   := _____

  PB04 LED SELOGIC Equation
PB04_LED   := _____

PB05 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB05LEDC**   := _____

  PB05 LED SELOGIC Equation
PB05_LED   := _____

PB06 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB06LEDC**   := _____

  PB06 LED SELOGIC Equation
PB06_LED   := _____

PB07 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB07LEDC**   := _____

  PB07 LED SELOGIC Equation
PB07_LED   := _____

PB08 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB08LEDC**   := _____

  PB08 LED SELOGIC Equation
PB08_LED   := _____

PB09 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB09LEDC**   := _____

  PB09 LED SELOGIC Equation
PB09_LED   := _____

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PB10 LED Asserted/Deasserted Colors (R,G,A,O) [2, 3]   **PB10LEDC**   :=   _____

   PB10 LED SELOGIC Equation

PB10_LED   :=   _____

PB11 LED Asserted/Deasserted Colors (R,G,A,O) [3]   **PB11LEDC**   :=   _____

   PB11 LED SELOGIC Equation

PB11_LED   :=   _____

PB12 LED Asserted/Deasserted Colors (R,G,A,O) [3]   **PB12LEDC**   :=   _____

   PB12 LED SELOGIC Equation

PB12_LED   :=   _____

NOTE 2: Make PB01LEDC–PB10LEDC settings only when Tricolor LEDs are ordered.

NOTE 3: Setting is a two-letter combination of the letters R, G, A, O, where:

    Asserted/deasserted color choices: R=Red, G=Green, A=Amber, O=Off

    Asserted and deasserted colors must be different

    Example:

Setting	Condition	LED Beside Pushbutton 11
PB11LEDC := RA	PB11_LED = logical 1	Illuminates Red
PB11LEDC := RA	PB11_LED = logical 0	Illuminates Amber

Target LED Settings

See Table 5.3, and Figure 11.13.

Target LED01:

   Trip Latch (Y, N)   **T01LEDL**   :=   _____

   LED Asserted Color (R, G, A) [4, 5]   **T01LEDC**   :=   _____

   SELOGIC Equation

T01_LED   :=   _____

Target LED02:

   Trip Latch (Y, N)   **T02LEDL**   :=   _____

   LED Asserted Color (R, G, A) [4, 5]   **T02LEDC**   :=   _____

   SELOGIC Equation

T02_LED   :=   _____

Target LED03:

   Trip Latch (Y, N)   **T03LEDL**   :=   _____

   LED Asserted Color (R, G, A) [4, 5]   **T03LEDC**   :=   _____

   SELOGIC Equation

T03_LED   :=   _____

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Target LED04:

Trip Latch (Y, N)   **T04LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T04LEDC** := _____

SELOGIC Equation
T04_LED := _____

Target LED05:

Trip Latch (Y, N)   **T05LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T05LEDC** := _____

SELOGIC Equation
T05_LED := _____

Target LED06:

Trip Latch (Y, N)   **T06LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T06LEDC** := _____

SELOGIC Equation
T06_LED := _____

Target LED07:

Trip Latch (Y, N)   **T07LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T07LEDC** := _____

SELOGIC Equation
T07_LED := _____

Target LED08:

Trip Latch (Y, N)   **T08LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T08LEDC** := _____

SELOGIC Equation
T08_LED := _____

Target LED09:

Trip Latch (Y, N)   **T09LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T09LEDC** := _____

SELOGIC Equation
T09_LED := _____

Target LED10:

Trip Latch (Y, N)   **T10LEDL** := _____

LED Asserted Color (R, G, A) [4, 5]   **T10LEDC** := _____

SELOGIC Equation
T10_LED := _____

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Target LED11:

    Trip Latch (Y, N)   **T11LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T11LEDC**   := _____

    SELOGIC Equation
    T11_LED   := _____

Target LED12:

    Trip Latch (Y, N)   **T12LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T12LEDC**   **:=** _____

    SELOGIC Equation
    T12_LED   := _____

Target LED13:

    Trip Latch (Y, N)   **T13LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T13LEDC**   := _____

    SELOGIC Equation
    T13_LED   := _____

Target LED14:

    Trip Latch (Y, N)   **T14LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T14LEDC**   := _____

    SELOGIC Equation
    T14_LED   := _____

Target LED15:

    Trip Latch (Y, N)   **T15LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T15LEDC**   := _____

    SELOGIC Equation
    T15_LED   := _____

Target LED16:

    Trip Latch (Y, N)   **T16LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T16LEDC**   := _____

    SELOGIC Equation
    T16_LED   := _____

Target LED17:

    Trip Latch (Y, N)   **T17LEDL**   := _____

    LED Asserted Color (R, G, A) [4,5]   **T17LEDC**   := _____

    SELOGIC Equation
    T17_LED   := _____

Date _____

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Target LED18:

Trip Latch (Y, N)   **T18LEDL**   := _____

LED Asserted Color (R, G, A)[4, 5]   **T18LEDC**   := _____

SELOGIC Equation
T18_LED   := _____

Target LED19:

Trip Latch (Y, N)   **T19LEDL**   := _____

LED Asserted Color (R, G, A)[4, 5]   **T19LEDC**   := _____

SELOGIC Equation
T19_LED   := _____

Target LED20:

Trip Latch (Y, N)   **T20LEDL**   := _____

LED Asserted Color (R, G, A) [4, 5]   **T20LEDC**   := _____

SELOGIC Equation
T20_LED   := _____

Target LED21:

Trip Latch (Y, N)   **T21LEDL**   := _____

LED Asserted Color (R, G, A) [4, 5]   **T21LEDC**   := _____

SELOGIC Equation
T21_LED   := _____

Target LED22:

Trip Latch (Y, N)   **T22LEDL**   := _____

LED Asserted Color (R,G,A) [4, 5]   **T22LEDC**   := _____

SELOGIC Equation
T22_LED   := _____

Target LED23:

Trip Latch (Y, N)   **T23LEDL**   := _____

LED Asserted Color (R, G, A) [4, 5]   **T23LEDC**   := _____

SELOGIC Equation
T23_LED   := _____

Target LED24:

Trip Latch (Y, N)   **T24LEDL**   := _____

LED Asserted Color (R, G, A) [4, 5]   **T24LEDC**   := _____

SELOGIC Equation
T24_LED   := _____

NOTE 4: Make T01LEDC−T24LEDC settings only when Tricolor LEDs are ordered.

NOTE 5: Asserted color choices: R=Red, G=Green, A=Amber

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Display Point Settings

See Rotating Display on page 11.13.

Number of display point settings dependent on preceding enable setting EDP := 1–32.

For all display point settings:

> ➤ Maximum 60 characters: 0–9, A–Z, -, /, ", ., {, }, space, comma

> ➤ Enter NA to clear a label.

> ➤ Use one of two types of settings:

> > ➢ **Boolean**: Relay Word Bit Name, "Alias", "Set String", "Clear String"

Example Setting	Condition	Display
DP04 := IN101,,"EXTERNAL ON","EXTERNAL OFF"	IN101 = Asserted	EXTERNAL ON
DP04 := IN101,,"EXTERNAL ON","EXTERNAL OFF"	IN101 = Deasserted	EXTERNAL OFF

> > ➢ **Analog**: Analog Quantity Name, "User Text and Formatting"

Example Setting	Condition	Display
DP05 := ICDEM,"C DEMAND={4.2,0.001} KA"	Always Displayed	C DEMAND=0.28 KA

DP01 := _____

DP02 := _____

DP03 := _____

DP04 := _____

DP05 := _____

DP06 := _____

DP07 := _____

DP08 := _____

DP09 := _____

DP10 := _____

DP11 := _____

DP12 := _____

DP13 := _____

DP14 := _____

DP15 := _____

DP16 := _____

DP17 := _____

DP18 := _____

DP19 := _____

DP20 := _____

DP21 := _____

DP22 := _____

DP23 := _____

DP24 := _____

Date _____

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DP25	:=	
DP26	:=	
DP27	:=	
DP28	:=	
DP29	:=	
DP30	:=	
DP31	:=	
DP32	:=	

Local Bit Settings

See Control Menu on page 11.7.

Number of local bit settings dependent on preceding enable setting ELB := 1–16.

For all local bit settings:

➤ Allowable characters: 0–9, A–Z, -, /, ., space

➤ Enter NA to clear a label.

For each Local Bit nn = 01–16, make settings:

➤ NLBnn is the local bit Name (label) (14 characters, maximum)

➤ CLBnn is the local bit Clear Label (7 characters, maximum)

➤ SLBnn is the local bit Set Label (7 characters, maximum)

➤ PLBnn is the local bit Pulse Label (7 characters, maximum)

See *Table 11.4* for the three possible local bit switch configurations.

Local Bit 01

Name (label) (14 characters maximum)	**NLB01**	:=
Clear Label (7 characters maximum)	**CLB01**	:=
Set Label (7 characters maximum)	**SLB01**	:=
Pulse Label (7 characters maximum)	**PLB01**	:=

Local Bit 02

Name (label) (14 characters maximum)	**NLB02**	:=
Clear Label (7 characters maximum)	**CLB02**	:=
Set Label (7 characters maximum)	**SLB02**	:=
Pulse Label (7 characters maximum)	**PLB02**	:=

Local Bit 03

Name (label) (14 characters maximum)	**NLB03**	:=
Clear Label (7 characters maximum)	**CLB03**	:=
Set Label (7 characters maximum)	**SLB03**	:=
Pulse Label (7 characters maximum)	**PLB03**	:=

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Local Bit 04

   Name (label) (14 characters maximum)   **NLB04**   :=

   Clear Label (7 characters maximum)   **CLB04**   :=

   Set Label (7 characters maximum)   **SLB04**   :=

   Pulse Label (7 characters maximum)   **PLB04**   :=

Local Bit 05

   Name (label) (14 characters maximum)   **NLB05**   :=

   Clear Label (7 characters maximum)   **CLB05**   :=

   Set Label (7 characters maximum)   **SLB05**   :=

   Pulse Label (7 characters maximum)   **PLB05**   :=

Local Bit 06

   Name (label) (14 characters maximum)   **NLB06**   :=

   Clear Label (7 characters maximum)   **CLB06**   :=

   Set Label (7 characters maximum)   **SLB06**   :=

   Pulse Label (7 characters maximum)   **PLB06**   :=

Local Bit 07

   Name (label) (14 characters maximum)   **NLB07**   :=

   Clear Label (7 characters maximum)   **CLB07**   :=

   Set Label (7 characters maximum)   **SLB07**   :=

   Pulse Label (7 characters maximum)   **PLB07**   :=

Local Bit 08

   Name (label) (14 characters maximum)   **NLB08**   :=

   Clear Label (7 characters maximum)   **CLB08**   :=

   Set Label (7 characters maximum)   **SLB08**   :=

   Pulse Label (7 characters maximum)   **PLB08**   :=

Local Bit 09

   Name (label) (14 characters maximum)   **NLB09**   :=

   Clear Label (7 characters maximum)   **CLB09**   :=

   Set Label (7 characters maximum)   **SLB09**   :=

   Pulse Label (7 characters maximum)   **PLB09**   :=

Local Bit 10

   Name (label) (14 characters maximum)   **NLB10**   :=

   Clear Label (7 characters maximum)   **CLB10**   :=

   Set Label (7 characters maximum)   **SLB10**   :=

   Pulse Label (7 characters maximum)   **PLB10**   :=

Date _____

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Local Bit 11

   Name (label) (14 characters maximum)   **NLB11**   := _____

   Clear Label (7 characters maximum)   **CLB11**   := _____

   Set Label (7 characters maximum)   **SLB11**   := _____

   Pulse Label (7 characters maximum)   **PLB11**   := _____

Local Bit 12

   Name (label) (14 characters maximum)   **NLB12**   := _____

   Clear Label (7 characters maximum)   **CLB12**   := _____

   Set Label (7 characters maximum)   **SLB12**   := _____

   Pulse Label (7 characters maximum)   **PLB12**   := _____

Local Bit 13

   Name (label) (14 characters maximum)   **NLB13**   := _____

   Clear Label (7 characters maximum)   **CLB13**   := _____

   Set Label (7 characters maximum)   **SLB13**   := _____

   Pulse Label (7 characters maximum)   **PLB13**   := _____

Local Bit 14

   Name (label) (14 characters maximum)   **NLB14**   := _____

   Clear Label (7 characters maximum)   **CLB14**   := _____

   Set Label (7 characters maximum)   **SLB14**   := _____

   Pulse Label (7 characters maximum)   **PLB14**   := _____

Local Bit 15

   Name (label) (14 characters maximum)   **NLB15**   := _____

   Clear Label (7 characters maximum)   **CLB15**   := _____

   Set Label (7 characters maximum)   **SLB15**   := _____

   Pulse Label (7 characters maximum)   **PLB15**   := _____

Local Bit 16

   Name (label) (14 characters maximum)   **NLB16**   := _____

   Clear Label (7 characters maximum)   **CLB16**   := _____

   Set Label (7 characters maximum)   **SLB16**   := _____

   Pulse Label (7 characters maximum)   **PLB16**   := _____

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Report Settings

(Serial Port Command SET R)

Sequential Events Recorder (SER) Trigger Lists

See Sequential Events Recorder (SER) Report on page 12.39.

Sequential Events Recorder settings are comprised of four trigger lists. Each trigger list can include as many as 24 Relay Word bits (see *Table F.1*) delimited by commas. Enter NA to remove a list of these Relay Word bit settings.

SER Trigger List 1
SER1 := _____

SER Trigger List 2
SER2 := _____

SER Trigger List 3
SER3 := _____

SER Trigger List 4
SER4 := _____

Event Report Settings

See Standard 15/30/60-Cycle Event Reports on page 12.2.

Length of Event Report (15, 30, 60 cycles)   **LER** := _____

Length of Prefault in Event Report   **PRE** := _____
  (1 to LER—1 cycle in 1-cycle steps)

Event Report Trigger SELOGIC Equation
ER := _____

Load Profile Settings

See Load Profile Report on page 8.44.

Load Profile List (15 elements max., enter NA to null)
LDLIST := _____

Load Profile Acquisition Rate (5,10,15,30,60 min)   **LDAR** := _____

NOTE: LDLIST may contain any elements listed in Table G.1 that have a dot in the "Load Profile" column.

High-Impedance Fault (HIF) Event Report Settings

(Ordering Option)
See High-Impedance Fault (HIF) Event Reporting on page 12.47.

Length of HIF Event Report (2, 5, 10, 20 min)   **HIFLER** := _____

HIF Event Report Trigger SELOGIC Equation
HIFER := _____

Date _____

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Port n Settings

(Serial Ports 1, 2, 3 and F (4) Serial Port SET P n Command and Front Panel)

Make Port 1 settings only if the relay is ordered with the EIA-485 port.

Port F and Port 4 are the same front-panel serial port.

Port Enable Settings

Enable Port (Y, N)   **EPORT**   := _____

NOTE: Setting EPORT = N completely disables the serial port, and hides all remaining port settings.

NOTE: The front-panel (Port F) EPORT setting controls both the EIA-232 serial port and the optional USB port.

NOTE: If the Access Jumper is not installed when EPORT is set to "N" on the front port and all other ports are disabled, or MAXACC < 2 on all enabled ports, the port can only be re-enabled via the HMI or by installing the Access Jumper and cycling power.

Protocol Selection

Protocol   **PROTO**   := _____
(SEL, DNP, MOD, MBA, MBB, MB8A, MB8B, PMU)

NOTE: Modbus protocol (PROTO = MOD) cannot be selected for the front-panel serial port (Port F).

Set PROTO = SEL for standard SEL ASCII protocol. Refer to Section 10: Communications for details on SEL ASCII protocol.

Set PROTO = DNP for Distributed Network Protocol (DNP). As many as six DNP sessions are available, shared between the serial ports and the Ethernet port. Refer to Appendix E: DNP3 Communications for details on DNP protocol.

Set PROTO = MOD for Modbus communications. As many as three Modbus sessions are available, shared between the serial ports and the Ethernet port. Refer to Appendix K: Modbus RTU and TCP Communications for details on Modbus protocol.

Set PROTO = MBA, MBB, MB8A, or MB8B for MIRRORED BITS. Only one port can be set to MBA or MB8A at a time. Only one port can be set to MBB or MB8B at a time. Refer to Appendix D: MIRRORED BITS Communications for details on MIRRORED BITS.

Set PROTO = PMU for IEEE C37.118 Synchrophasors. You must first make Global setting EPMU = Y to make this setting available. See Appendix J: Synchrophasors for details.

Make the following setting when PROTO = SEL or DNP on Port 1, 2, 3, or F.

Maximum Access Level (0, 1, B, 2, C)   **MAXACC**   := _____

NOTE: The MAXACC setting controls the availability of **ACC**, **BAC**, **2AC**, and **CAL** commands on this port.

NOTE: MAXACC for Port F (only) can be set to 1, B, 2, or C, and affects both Serial Port F and the USB port.

SEL Protocol Settings

Make the following settings when PROTO = SEL.

Data Rate (300, 1200, 2400, 4800, 9600, 19200, 38400, 57600)   **SPEED**   := _____

Data Bits (6, 7, 8)   **BITS**   := _____

Parity (O, E, N) {Odd, Even, None}   **PARITY**   := _____

Stop Bits (1, 2)   **STOP**   := _____

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Enable Hardware Handshaking (Y, N)   **RTSCTS**   := _____

Set RTSCTS = Y to enable hardware handshaking. With RTSCTS = Y, the relay will not send characters until the CTS input is asserted. Also, if the relay is unable to receive characters, it deasserts the RTS line (see Hardware Handshaking on page 10.9).

NOTE: The RTSCTS setting is not available on Port 1.

Minutes to Port Time-out (0–30 minutes)   **T_OUT**   := _____

Set T_OUT to the number of minutes of serial port inactivity for an automatic log out. Set T_OUT = 0 for no port time out.

Send Auto Messages to Port (Y, N)   **AUTO**   := _____

Set AUTO = Y to allow automatic messages at the serial port. See Serial Port and Telnet Session Automatic Messages on page 10.21.

Fast Operate Enable (Y, N)   **FASTOP**   := _____

Set FASTOP = Y to enable binary Fast Operate messages at the serial port. Set FASTOP = N to block binary Fast Operate messages. Refer to Appendix I: Configuration, Fast Meter, and Fast Operate Commands for the description of the SEL-651R-2 Fast Operate commands.

DNP Settings

Make the following settings when PROTO = DNP.

Data Rate (300, 1200, 2400, 4800, 9600, 19200, 38400, 57600)   **SPEED**   := _____

Parity (O, E, N) {Odd, Even, None}   **PARITY**   := _____

Stop Bits (1, 2)   **STOP**   := _____

Minutes to Port Time-out (0–30 minutes)   **T_OUT**   := _____

Set T_OUT to the number of minutes of serial port inactivity for an automatic log out. Set T_OUT = 0 for no port time out. T_OUT applies to DNP virtual terminal only.

DNP Address (0–65519)   **DNPADR**   := _____

DNP Address to Report to (0–65519)   **REPADR**   := _____

DNP Session Map (1–3)   **DNPMAP**   := _____

Analog Input Default Variation (1–6)   **DVARAI**   := _____

Class for Binary Event Data (0–3)   **ECLASSB**   := _____

Class for Counter Event Data (0–3)   **ECLASSC**   := _____

Class for Analog Event Data (0–3)   **ECLASSA**   := _____

Class for Virtual Terminal Response Data (0–3)   **ECLASSV**   := _____

Currents Scaling Decimal Places (0–3)   **DECPLA**   := _____

Voltages Scaling Decimal Places (0–3)   **DECPLV**   := _____

Miscellaneous Data Scaling Decimal Places (0–3)   **DECPLM**   := _____

Make the following two settings when ECLASSA > 0.

Amperes Reporting Dead Band Counts (0–32767)   **ANADBA**   := _____

Volts Reporting Dead Band Counts (0–32767)   **ANADBV**   := _____

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Make the following setting when ECLASSA > 0 or ECLASSC > 0.

Miscellaneous Data Reporting Dead Band Counts (0–32767)	**ANADBM**	:= _____
Minutes for Request Interval (I, M, 1–32767)	**TIMERQ**	:= _____

NOTE: TIMERQ = I: Disables time-sync requests and ignores syncs from master.

NOTE: TIMERQ = M: Disables time-sync requests and processes time syncs from master.

NOTE: TIMERQ = m = 1–32767: Relay requests a time-sync every m minutes.

Seconds to Select/Operate Time-out (0.0–30.0 seconds in 0.1 second steps)	**STIMEO**	:= _____
Data Link Retries (0–15)	**DRETRY**	:= _____

Make the following setting when DRETRY > 0.

Seconds to Data Link Time-out (0–5 seconds in 1 second steps)	**DTIMEO**	:= _____
Max Response Size (200–2411 in bytes)	**RESPSZ**	:= _____
Event Message Confirm Time-out (1–120 seconds in 1 second steps)	**ETIMEO**	:= _____

Make the following setting when ECLASSB > 0, ECLASSC > 0 or ECLASSA > 0.

Enable Unsolicited Reporting (Y, N)	**UNSOL**	:= _____

Make the following nine settings when UNSOL = Y.

Enable Unsolicited Reporting at Power-Up (Y, N)	**PUNSOL**	:= _____
Number of Class 1 Events to Transmit On (1–200)	**NUM1EVE**	:= _____
Oldest Class 1 Event to Transmit On (0.0–99999.0 seconds in 0.1 second steps)	**AGE1EVE**	:= _____
Number of Class 2 Events to Transmit On (1–200)	**NUM2EVE**	:= _____
Oldest Class 2 Event to Transmit On (0.0–99999.0 seconds in 0.1 second steps)	**AGE2EVE**	:= _____
Number of Class 3 Events to Transmit On (1–200)	**NUM3EVE**	:= _____
Oldest Class 3 Event to Transmit On (0.0–99999.0 seconds in 0.1 second steps)	**AGE3EVE**	:= _____
Unsolicited Message Maximum Retry Attempts (2–10)	**URETRY**	:= _____
Unsolicited Message Offline Time-out (OFF, 2–5000 seconds in 1 second steps)	**UTIMEO**	:= _____

NOTE: UTIMEO must be greater than ETIMEO.

Minimum Seconds from DCD to Transmit (0.00–1.00 seconds in 0.01 second steps)	**MINDLY**	:= _____
Maximum Seconds from DCD to Transmit (0.00–1.00 seconds in 0.01 second steps)	**MAXDLY**	:= _____

NOTE: MAXDLY must be greater than MINDLY.

Settle Time from RTS ON to Transmit (OFF, 0.00–30.00 seconds in 0.01 second steps)	**PREDLY**	:= _____

Make the following setting when PREDLY ≠ OFF.

Settle Time from Transmit to RTS OFF (0.00–30.00 seconds in 0.01 second steps)	**PSTDLY**	:= _____

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Event Mode (SINGLE, MULTI) **EVEMODE** := _____

Report Event Type (TRIP, ALL) **RPEVTYP** := _____

Modem Connected to Port (Y, N) **MODEM** := _____

Make setting MSTR when MODEM := Y.

Modem Startup String (30 characters maximum)
   MSTR := _____

Make settings PH_NUM1, PH_NUM2, RETRY1, RETRY2, MDTIME, and MDRET when MODEM := Y and UNSOL := Y.

Phone number 1 for Dial-Out (30 characters maximum)
   PH_NUM1 := _____

Phone Number 2 for Dial-Out (30 characters maximum; leave blank if not used)
   PH_NUM2 := _____

Retry Attempts for Phone Number 1 Dial-Out (1–20) **RETRY1** := _____

Retry Attempts for Phone Number 2 Dial-Out (1–20) **RETRY2** := _____

Time to Attempt Dial (5–300 seconds) **MDTIME** := _____

Time Between Dial-Out Attempts (5–3600 seconds) **MDRET** := _____

See Appendix E: DNP3 Communications for full settings explanations and other required settings.

PMU Protocol Port Settings

Make the following settings when PROTO = PMU.

Data Rate (300, 1200, 2400, 4800, 9600, 19200, 38400, 57600) **SPEED** := _____

NOTE: Global Synchrophasor settings for message size and rate may restrict the minimum SPEED setting. See Appendix J: Synchrophasors for details.

Stop Bits (1, 2) **STOP** := _____

Enable Hardware Handshaking (Y, N) **RTSCTS** := _____

Set RTSCTS = Y to enable hardware handshaking. With RTSCTS = Y, the relay will not send characters until the CTS input is asserted. Also, if the relay is unable to receive characters, it deasserts the RTS line (see Hardware Handshaking on page 10.9).

NOTE: The RTSCTS setting is not available on Port 1.

Fast Operate Enable (Y, N) **FASTOP** := _____

Set FASTOP = Y to enable binary Fast Operate messages at the serial port. Set FASTOP = N to block binary Fast Operate messages. Refer to Appendix I: Configuration, Fast Meter, and Fast Operate Commands for the description of the SEL-651R-2 Fast Operate commands.

SEL MIRRORED BITS Protocol Settings

Make the following settings when PROTO = MBA, MBB, MB8A, MB8B.

Data Rate (300, 1200, 2400, 4800, 9600, 19200, 38400, 57600) **SPEED** := _____

Enable Hardware Handshaking (Y, N, MBT) **RTSCTS** := _____

Set RTSCTS = Y to enable hardware handshaking. With RTSCTS = Y, the relay will not send characters until the CTS input is asserted. Also, if the relay is unable to receive characters, it deasserts the RTS line (see

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Hardware Handshaking on page 10.9). See Appendix D: MIRRORED BITS Communications for information on the MBT setting choice.

NOTE: The RTSCTS setting is not available on Port 1. The MBT setting option is only available when PROTO = MBA or MBB, and SPEED = 9600.

MIRRORED BITS Transmit Identifier (1–4)	**TXID**	:= _____
MIRRORED BITS Receive Identifier (1–4)	**RXID**	:= _____
MIRRORED BITS Rx Bad Pickup Time (1–10000 seconds in 1 second steps)	**RBADPU**	:= _____
PPM MIRRORED BITS Channel Bad Pickup (1–10000)	**CBADPU**	:= _____
MIRRORED BITS Receive Default String (string of 1s, 0s, or Xs) Display order: 87654321	**RXDFLT**	:= _____
MIRRORED BITS RMB1 Pickup Debounce Messages (1–8)	**RMB1PU**	:= _____
MIRRORED BITS RMB1 Dropout Debounce Messages (1–8)	**RMB1DO**	:= _____
MIRRORED BITS RMB2 Pickup Debounce Messages (1–8)	**RMB2PU**	:= _____
MIRRORED BITS RMB2 Dropout Debounce Messages (1–8)	**RMB2DO**	:= _____
MIRRORED BITS RMB3 Pickup Debounce Messages (1–8)	**RMB3PU**	:= _____
MIRRORED BITS RMB3 Dropout Debounce Messages (1–8)	**RMB3DO**	:= _____
MIRRORED BITS RMB4 Pickup Debounce Messages (1–8)	**RMB4PU**	:= _____
MIRRORED BITS RMB4 Dropout Debounce Messages (1–8)	**RMB4DO**	:= _____
MIRRORED BITS RMB5 Pickup Debounce Messages (1–8)	**RMB5PU**	:= _____
MIRRORED BITS RMB5 Dropout Debounce Messages (1–8)	**RMB5DO**	:= _____
MIRRORED BITS RMB6 Pickup Debounce Messages (1–8)	**RMB6PU**	:= _____
MIRRORED BITS RMB6 Dropout Debounce Messages (1–8)	**RMB6DO**	:= _____
MIRRORED BITS RMB7 Pickup Debounce Messages (1–8)	**RMB7PU**	:= _____
MIRRORED BITS RMB7 Dropout Debounce Messages (1–8)	**RMB7DO**	:= _____
MIRRORED BITS RMB8 Pickup Debounce Messages (1–8)	**RMB8PU**	:= _____
MIRRORED BITS RMB8 Dropout Debounce Messages (1–8)	**RMB8DO**	:= _____

See Appendix D: MIRRORED BITS Communications for full settings explanations and other required settings.

Modbus Protocol Settings

Make the following settings when PROTO = MOD)

Data Rate (300, 1200, 2400, 4800, 9600, 19200, 38400, 57600)	**SPEED**	:= _____
Parity (O, E, N) {Odd, Even, None}	**PARITY**	:= _____
Modbus Slave ID (1–247)	**SLAVEID**	:= _____

See Appendix K: Modbus RTU and TCP Communications for full settings explanations and other required settings.

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Port 5 Settings

(Serial Port SET P 5 Command (for Ethernet Port 5, or 5A and 5B))

Port Enable Setting

Enable Port (Y, N)   **EPORT**   := _____

NOTE: Setting EPORT = N completely disables the Ethernet port, and hides all remaining port settings.

Ethernet Port Settings

IP addresses are entered as zzz.yyy.xxx.www, where zzz = 1-126, 128-223; yyy = 0-255; xxx = 0-255; www = 0-255.

Device IP Address (zzz.yyy.xxx.www)   **IPADDR**   := _____

Subnet Mask (zzz.yyy.xxx.www)   **SUBNETM** := _____

Default Router (zzz.yyy.xxx.www)   **DEFRTR**   := _____

NOTE: Setting DEFRTR = 0.0.0.0 disables the default router.

Enable TCP Keep-Alive (Y, N)   **ETCPKA**   := _____

TCP Keep-Alive is enabled with default range settings for PMU sessions even when ETCPKA = N.

Make the following three settings when ETCPKA = Y.

TCP Keep-Alive Idle Range (1–20 seconds in 1 second steps)   **KAIDLE**   := _____

TCP Keep-Alive Interval Range
(1–20 seconds in 1 second steps)   **KAINTV**   := _____

TCP Keep-Alive Count Range (1–20)   **KACNT**   := _____

Make the following setting when the relay has dual Ethernet.

Operating Mode (FIXED, FAILOVER, SWITCHED)   **NETMODE** := _____

Make the following setting when NETMODE = FAILOVER.

Failover Time-out
(OFF, 0.10–65.00 seconds in 0.01 second steps)   **FTIME**   := _____

Make the following setting when NETMODE = FIXED or FAILOVER.

Primary Net Port (A, B)   **NETPORT** := _____

Make the following settings for each enabled port when the relay has dual 10/100BASE-T (copper).

Port 5A Speed (AUTO, 10, 100 Mbps)   **NET5ASPD** := _____

Port 5B Speed (AUTO, 10, 100 Mbps)   **NET5BSPD** := _____

Make the following setting when the relay has single 10/100BASE-T (copper).

Port 5 Speed (AUTO, 10, 100 Mbps)   **NET5SPD** := _____

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Telnet Settings

Enable Telnet (Y, N)   **ETELNET**   := _____

Make the following settings when ETELNET = Y.

Maximum Access Level (0, 1, B, 2, C)   **MAXACC**   := _____

NOTE: The MAXACC setting controls the availability of the **ACC**, **BAC**, **2AC**, and **CAL** commands in the Telnet session.

Telnet Port (23, 1025–65534)   **TPORT**   := _____

Telnet Connect Banner (254 characters maximum. Use "\n" to create a new line).

TCBAN   := _____

_____

Telnet Port Time-out (1–30 minutes in 1 minute steps)   **TIDLE**   := _____

Send Auto Messages to Port (Y, N)   **AUTO**   := _____

Set AUTO = Y to allow automatic messages on the Telnet session (similar to serial port auto message–see Serial Port and Telnet Session Automatic Messages on page 10.21).

Fast Operate Enable (Y, N)   **FASTOP**   := _____

Set FASTOP = Y to enable binary Fast Operate messages on the Telnet session. Set FASTOP = N to block binary Fast Operate messages. Refer to Appendix I: Configuration, Fast Meter, and Fast Operate Commands for the description of the SEL-651R-2 Fast Operate commands.

See Section 10: Communications for full settings explanations and other required settings.

File Transfer Protocol (FTP) Server Settings

Enable FTP (Y, N)   **EFTPSERV**   := _____

Make the following settings when EFTPSERV = Y.

FTP User Name (20 characters maximum)   **FTPUSER**   := _____

FTP Connect Banner (254 characters maximum) Use "\n" to create a new line).

FTPCBAN := _____

_____

FTP Idle Timeout (5–255 minutes)   **FTPIDLE**   := _____

Hypertext Transfer Protocol (HTTP) Web Server Settings

Enable HTTP Server (Y, N)   **EHTTP**   := _____

Make the following settings when EHTTP = Y)

HTTP Maximum Access Level (1, 2)   **HTTPACC**   := _____

TCP/IP Port (1–65535)   **HTTPPORT**   := _____

NOTE: HTTPPORT may not be set to reserved port numbers 20, 21, 102, 502, or the same as other settings listed in Table SET.1.

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HTTP Connect Banner (254 characters maximum) Use "\n" to create a new line).

HTTPBAN :=

HTTP Web Server Timeout (1–30 minutes in 1 minute steps)   **HTTPIDLE** :=

Firmware Upgrade Front-Panel Confirmation (Y, N)   **FWFPC** :=

IEC 61850 Protocol Settings

Ordering Option.

Enable IEC 61850 Protocol (Y, N)   **E61850** :=

Make the following setting when E61850 = Y.

Enable IEC 61850 GSE (Y, N)   **EGSE** :=

Enable MMS File Services (Y, N)   **EMMSFS** :=

Ethernet DNP Settings

Enable DNP Sessions (0–6)   **EDNP** :=

Make the following settings when EDNP > 0.

DNP TCP and UDP Port (1–65534)   **DNPNUM** :=

NOTE: DNPNUM may not be set to reserved port numbers 20, 21, 102, 502, or the same as other settings listed in Table SET.1.

DNP Address (0–65519)   **DNPADR** :=

DNP Master n Settings

Repeat for n = 1-6; as high as EDNP Value.

Make the following settings when EDNP > 0.

IP Address (zzz.yyy.xxx.www)   **DNPIP*n*** :=

NOTE: The DNP IP address of each session (DNPIP1, DNPIP2, etc.) must be unique.

Transport Protocol (UDP, TCP)   **DNPTR*n*** :=

Make the following setting when DNPTRn = UDP.

UDP Response Port (REQ, 1–65534)   **DNPUDP*n*** :=

NOTE: DNPUDPn = REQ directs response to same port message was received from.

DNP Address to Report to (0–65519)   **REPADR*n*** :=

DNP Session Map (1–3)   **DNPMAP*n*** :=

Analog Input Default Variation (1–6)   **DVARAI*n*** :=

Class for Binary Event Data (0–3)   **ECLASSB*n*** :=

Class for Counter Event Data (0–3)   **ECLASSC*n*** :=

Class for Analog Event Data (0–3)   **ECLASSA*n*** :=

Currents Scaling Decimal Places (0–3)   **DECPLA*n*** :=

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Voltages Scaling Decimal Places (0–3)   **DECPLV*n*** := _____

Miscellaneous Data Scaling Decimal Places (0–3)   **DECPLM*n*** := _____

Make the following two settings when ECLASSAn > 0.

Amperes Reporting Dead Band Counts (0–32767)   **ANADBA*n*** := _____

Volts Reporting Dead Band Counts (0–32767)   **ANADBV*n*** := _____

Make the following setting when ECLASSAn > 0 or ECLASSCn > 0.

Miscellaneous Data Reporting Dead Band Counts (0–32767)   **ANADBM*n*** := _____

Minutes for Request Interval (I, M, 1–32767)   **TIMERQ*n*** := _____

NOTE: TIMERQn = I: Disables time-sync requests and ignores syncs from master.

NOTE: TIMERQn = M: Disables time-sync requests and processes time syncs from master.

NOTE: TIMERQn = m = 1-32767: Relay shall request a time-sync every m minutes.

Seconds to Select/Operate Time-out
  (0.0–30.0 seconds in 0.1 second steps)   **STIMEO*n*** := _____

Make the following setting when DNPTRn = TCP.

Seconds to Send Data Link Heartbeat
  (0–7200 seconds in 1 second steps)   **DNPINA*n*** := _____

Event Message Confirm Time-out
  (1–120 seconds in 1 second steps)   **ETIMEO*n*** := _____

Make the following setting when ECLASSBn > 0, ECLASSCn > 0, or ECLASSAn > 0.

Enable Unsolicited Reporting (Y, N)   **UNSOL*n*** := _____

Make the following five settings when UNSOLn = Y.

Enable Unsolicited Reporting at Power-Up (Y, N)   **PUNSOL*n*** := _____

Number of Class 1 Events to Transmit On (1–200)   **NUM1EVE*n*** := _____

Oldest Class 1 Event to Tx On
  (0.0–99999.0 seconds in 0.1 second steps)   **AGE1EVE*n*** := _____

Number of Class 2 Events to Transmit On (1–200)   **NUM2EVE*n*** := _____

Oldest Class 2 Event to Tx On
  (0.0–99999.0 seconds in 0.1 second steps)   **AGE2EVE*n*** := _____

Number of Class 3 Events to Transmit On (1–200)   **NUM3EVE*n*** := _____

Oldest Class 3 Event to Tx On
  (0.0–99999.0 seconds in 0.1 second steps)   **AGE3EVE*n*** := _____

Unsolicited Message Max Retry Attempts (2–10)   **URETRY*n*** := _____

Unsolicited Message Offline Time-out
  (2–5000 seconds in 1 second steps)   **UTIMEO*n*** := _____

NOTE: UTIMEOn must be greater than ETIMEOn.

Event Mode (SINGLE, MULTI)   **EVEMODE*n*** := _____

Report Event Type (TRIP, ALL)   **RPEVTYP*n*** := _____

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Ethernet Synchrophasor Settings

Make the following settings when Global settings EPMU = Y.

Enable PMU Processing (Y, N)　　　　　　　**EPMIP**　　:= _____

PMU Output 1 Settings

Make the following setting when EPMIP = Y.

PMU Output 1 Transport Scheme　　　　　　**PMOTS1**　　:= _____
　(OFF, TCP, UDP_S, UDP_T, UDP_U)

Make the following settings when PMOTS1 ≠ OFF.

PMU Output 1 Client IP (Remote) Address (zzz.yyy.xxx.www)　**PMOIPA1**　:= _____

NOTE: PMOIPA1 cannot be set to the same address as IPADDR. IP addresses from 224.0.0.1 through 239.255.255.255 are also valid when PMOTS1 = UDP_S. IP address 255.255.255.255 is also valid when PMOTS1 = UDP_S or TCP.

Make the following setting when PMOTS1 ≠ UDP_S.

PMU Output 1 TCP/IP (Local) Port Number (1–65534)　　**PMOTCP1**　:= _____

NOTE: PMOTCP1 cannot be set to the same number as PMOTCP2.

NOTE: PMOTCP1 cannot be set to 20, 21, 102, 502, or the same as the other settings listed in Table SET.1.

Make the following setting when PMOTS1 = UDP_S, UDP_T, or UDP_U.

PMU Output 1 UDP/IP Data (Remote) Port Number (1–65534)　　**PMOUDP1**　:= _____

PMU Output 2 Settings

Make the following setting when EPMIP = Y (and E61850 = N on relays ordered with IEC 61850 protocol).

PMU Output 2 Transport Scheme　　　　　　**PMOTS2**　　:= _____
　(OFF, TCP, UDP_S, UDP_T, UDP_U)

Make the following settings when PMOTS2 ≠ OFF.

PMU Output 2 Client IP (Remote) Address (zzz.yyy.xxx.www)　**PMOIPA2**　:= _____

NOTE: PMOIPA2 cannot be set to the same address as IPADDR. IP addresses from 224.0.0.1 through 239.255.255.255 are also valid when PMOTS2 = UDP_S. IP address 255.255.255.255 is also valid when PMOTS2 = UDP_S or TCP.

Make the following setting when PMOTS2 ≠ UDP_S.

PMU Output 2 TCP/IP (Local) Port Number (1–65534)　　**PMOTCP2**　:= _____

NOTE: PMOTCP2 cannot be set to the same number as PMOTCP1.

NOTE: PMOTCP2 cannot be set to 20, 21, 102, 502, or the same as the other settings listed in Table SET.1.

Make the following setting when PMOTS2 = UDP_S, UDP_T, or UDP_U.

PMU Output 2 UDP/IP Data (Remote) Port Number (1–65534)　　**PMOUDP2**　:= _____

Ethernet Modbus Settings

Enable Modbus (0–3)　　　　　　　　　**EMODBUS**　:= _____

NOTE: Setting EMODBUS cannot be set (must remain EMODBUS := 0) if more than three Ethernet DNP sessions are enabled (EDNP > 3).

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Make the following settings when EMODBUS ≥ 1.

Ethernet Modbus Settings: Master 1

    IP Address (zzz.yyy.xxx.www)   **MODIP1**   := _____

NOTE: MODIP1, MODIP2, and MODIP3 cannot share an address (except 0.0.0.0).

    Modbus Session Time-out (15–900 seconds in 1 second steps)   **MTIMEO1**   := _____

Make the following settings when EMODBUS ≥ 2.

Ethernet Modbus Settings: Master 2

    IP Address (zzz.yyy.xxx.www)   **MODIP2**   := _____

NOTE: MODIP1, MODIP2, and MODIP3 cannot share an address (except 0.0.0.0).

    Modbus Session Time-out (15–900 seconds in 1 second steps)   **MTIMEO2**   := _____

Make the following settings when EMODBUS = 3.

Ethernet Modbus Settings: Master 3

    IP Address (zzz.yyy.xxx.www)   **MODIP3**   := _____

NOTE: MODIP1, MODIP2, and MODIP3 cannot share an address (except 0.0.0.0).

    Modbus Session Time-out (15–900 seconds in 1 second steps)   **MTIMEO3**   := _____

SNTP Client Protocol Settings

    Enable SNTP Client (OFF, UNICAST, MANYCAST,   **ESNTP**   := _____
      BROADCAST)

Make the following settings when ESNTP ≠ OFF.

    Primary Server IP Address (zzz.yyy.xxx.www)   **SNTPPSIP** := _____

NOTE: To accept updates from any server when ESNTP = BROADCAST, set SNTPPSIP to 0.0.0.0. Only IP
        addresses in the range 224.0.0.1 through 239.255.255.255 are valid when ESNTP = MANYCAST.

Make the following setting when ESNTP = UNICAST.

    Backup Server IP Address (zzz.yyy.xxx.www)   **SNTPBSIP** := _____

    SNTP IP (Local) Port Number (1–65534)   **SNTPPORT** := _____

NOTE: SNTPPORT cannot be set to the same value as DNPNUM when EDNP > 0.

    SNTP Update Rate (15–3600 seconds in 1 second steps)   **SNTPRATE** := _____

Make the following setting when ESNTP = UNICAST or MANYCAST.

    SNTP Timeout (5–20 seconds in 1 second steps)   **SNTPTO**   := _____

NOTE: SNTPTO must be less than setting SNTPRATE.

Port Number Settings Must Be Unique

When making the SEL-651R-2 Port 5 settings, port number settings cannot be used for more than one protocol. The relay checks all of the settings shown in *Table SET.1* before saving changes. If a port number is used more than once, the relay will display an error message, and return to the first setting that contains the duplicate value.

Table SET.1 Port Number Settings That Must Be Unique

Setting	Name	Setting Required When...
TPORT	Telnet Port	ETELNET = Y
HTTPPORT	TCP/IP Port	EHTTP = Y
DNPNUM	DNP TCP and UDP Port	EDNP > 0
PMOTCP1	PMU Output 1 TCP/IP (Local) Port Number	PMOTS1 = TCP, UDP_T, or UDP_U
PMOTCP2	PMU Output 2 TCP/IP (Local) Port Number	PMOTS2 = TCP, UDP_T, or UDP_U

Section 10

Communications

Introduction

The SEL-651R-2 Recloser Control has as many as seven communications ports as shown in *Table 10.1*. Use the communications ports to establish local and remote communications with the relay using numerous communications protocols.

Table 10.1   SEL-651R-2 Communications Ports

Port Number	Type	Location	Standard/ Optional
1	EIA-485 Serial		Standard
2	EIA-232 Serial	For the locations of the communications ports, see *Figure 2.4* and *Figure 2.5* for dual-door enclosure models, and *Figure 2.8* for single-door enclosure models.	Standard
3	EIA-232 Serial		Standard
4 or F	EIA-232 Serial		Standard
5	Single Ethernet	**Note:** When the SEL-651R-2 is ordered with the Dual Ethernet option, Port 5 is replaced by Ports 5A and 5B.	Optional[a]
5A/5B	Dual Ethernet		Optional[a]
N/A	USB		Standard

[a]   Select either single or dual Ethernet.

The first part of this section shows how to establish local communications with the relay using serial, USB, Ethernet ports and the SEL ASCII communications protocol, or the built-in web server. Other parts of this section provide reference information to help you use recloser control communications ports to establish local and remote communications for engineering access, SCADA communications, teleprotection, and synchrophasor data collection. Use of actual communications protocols such as IEC 61850, DNP, Modbus, or SEL MIRRORED BITS communications is covered in various appendices of this manual.

Establishing Communications Using a Serial Port

Use the front serial port and any terminal emulation program or the ACSELERATOR QuickSet SEL-5030 Software to begin communicating with the relay. Connect an SEL-C234 or SEL-C662 cable between the relay and a personal computer. The serial port default communications parameters are:

➤ Data Rate = 9600

➤ Data Bits = 8

➤ Parity = N

➤ Stop Bits = 1

Use the **SET P** command to change the recloser control communications port parameters.

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Establishing Communications Through Use of the USB Port
USB Port Overview

The USB port has no settings and is faster than the serial ports, especially for operations requiring transport of large blocks of data such as long event reports or firmware upgrades.

Each time you connect a relay to your PC USB port, Windows determines if a driver has already been installed and is ready for use. There are three possibilities:

1. Connect a PC for the first time to a relay USB port.

   Windows launches the **Found New Hardware Wizard**. The wizard guides you through the USB driver installation process and creates a new virtual COM port (e.g., COM 4).

   See *Detailed Instructions for USB Port Driver Installation* below before connecting the relay to your PC USB port.

2. Reconnect a PC to a relay USB port by using a different physical USB port on a PC (i.e., same PC, different physical USB port on the PC).

   Windows launches the **Found New Hardware Wizard**. Select **Install the software automatically (Recommended)** and click **Next**. Windows locates the required INF file and driver and creates a new virtual COM port (e.g., COM 5).

   Windows creates a new virtual COM port (e.g., COM 6, COM 7) each time you connect a relay to a physical USB port that has not previously been connected to a relay. The virtual COM port number remains associated with the same physical USB port until you uninstall the driver.

3. Reconnect a PC to a relay USB port using a physical USB port on the PC that has already been connected to a relay (i.e., same PC, same physical USB port on the PC).

   Windows recognizes that the driver is already installed and creates the same virtual COM port created the first time you connected a relay to that particular physical USB port (e.g., COM 4). No action is required on your part.

The USB driver exposes normal communications port settings to the personal computer operating system, such as data rate, parity, etc. to maintain compatibility with many PC applications. Changing these settings in the PC does not change how the recloser control USB port operates. You may use a PC Terminal Emulator program or dedicated software to connect to the SEL-651R-2 via USB port. The USB port offers a subset of the functionality of a standard serial port. See *Table 10.6* for details.

USB uses a connection-based protocol. Under certain circumstances, such as power cycling the relay, the USB connection may be terminated. If the USB connection is terminated it may be necessary to reconnect to the relay by using the PC application software, or disconnect and then reconnect the USB connector at either the PC or the relay.

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QuickSet is more tolerant of unexpected USB device disconnections than most other PC applications. While using QuickSet, it is possible to disconnect the USB cable from one relay and move it to another relay without the need to restart the application, reselect the COM port, or even disconnect and reconnect at the application level.

Detailed Instructions for USB Port Driver Installation

The following detailed instructions for USB driver installation are specifically for the Windows XP operating system. Some steps may be different and some screens may be changed for other Windows operating systems. For USB driver installation instructions for Windows 7, see the SEL-651R-2 product page at selinc.com/products/651R/.

Step 1.   Retrieve the USB driver file "SEL Fast CDC USB Device.INF" from the SEL-651R-2 product page on the SEL website (selinc.com), from the SEL-651R-2 Product Literature CD, or from the SEL-5030 Installation CD. Place the INF file in any convenient directory, such as C:\SEL\Drivers\Relay_USB.

NOTE: The SEL-651R-2 USB driver is different than the driver used for the SEL-C662 (EIA-232 serial-to-USB converter cable) and the driver used for the SEL-2440 Discrete Programmable Automation Controller.

Step 2.   Connect the relay to your PC with an SEL-C664 cable, or any standard A to B USB cable. Your PC will recognize that a new device has been connected and will start the **Found New Hardware Wizard**. Select **No, not this time** and click **Next**. Some Windows XP systems will skip this screen and go to the screen shown in *Step 3*.

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Step 3.   Select **Install from a list or specific location (Advanced)**.
Click **Next**.

Step 4.   Select **Don't search. I will choose the driver to install**. Click
Next.

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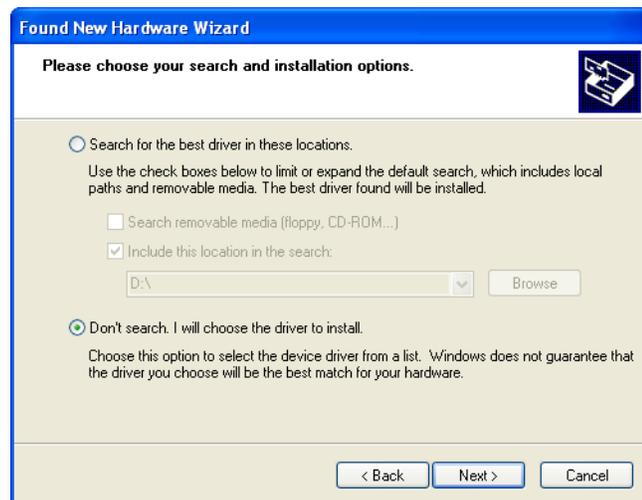
Step 5.   If prompted for a hardware type, select **Ports (COM & LPT)** and click **Next**. Some Windows XP systems will skip this screen and go to the next screen.

Step 6.   If necessary, click the **Have Disk** button and direct the wizard to the folder containing the INF file you copied to your local drive in *Step 1*. After you locate the INF file, the **Found New Hardware Wizard** will return to the screen shown below. Verify the selected **Model** is **SEL Fast CDC USB Device**. Click **Next**.

Step 7.   If Windows warns that the driver has not passed Windows Logo testing, verify that the name **SEL Fast CDC USB Device** matches the Model selected in *Step 6*, and then click **Continue Anyway**.

Step 8.   Wait while the wizard installs the driver software.

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Step 9.   Click **Finish** to finish the installation process.

The USB port driver is now installed and a new virtual COM port (e.g., COM 4) is ready for use. To see what virtual COM port has been created, launch any communications program that allows selection of a COM port and view the available ports, or go to the Windows Device Manager and inspect the available COM ports as shown below. Use Device Manager to verify which virtual COM port is associated with a particular physical USB port. Device Manager updates the available COM ports each time a cable is inserted or removed.
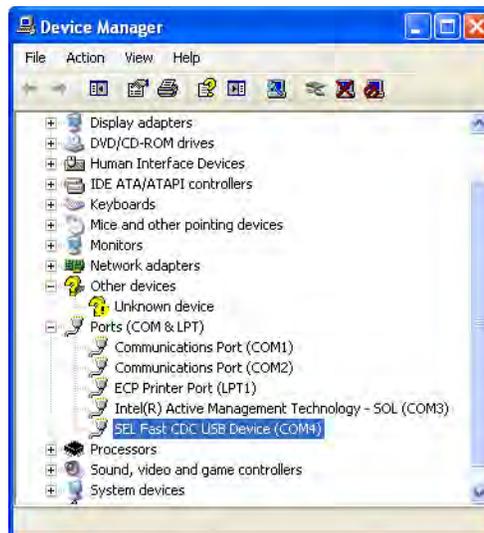
To test the USB port and the newly installed driver follow these steps:

Step 1.   Launch QuickSet and select **Communications > Parameters** from the menu or click the **Communications Parameters** icon from the opening screen. See *Section 3: PC Software* for more information on QuickSet. Select the new COM port created by the driver installation process, e.g., COM 4 in the screen capture. Ignore other settings like parity and data rate. They have no effect on how the USB port operates and are only presented to the operating system to retain compatibility with certain applications.

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Step 2.   Select **Communications > Terminal** from the menu, or click the terminal icon on the tool bar. Log into the relay normally. The USB port should work similarly to an EIA-232 port, only much faster. See *Table 10.6* for a list of features available from the USB port.

Establishing Communications Using an Ethernet Port and Telnet or the Web Server

Factory-default settings for the Ethernet ports disable all Ethernet protocols except PING. Enable the Telnet and web server protocols with the **SET P 5** command using any of the serial ports or the USB port. Command **SET P 5** accesses settings for Ethernet ports on the SEL-651R-2: Port 5, or Ports 5A and 5B (when ordered with the Dual Ethernet option).

See *SHO Command (Show/View Settings)* for a sample of the **SHO P 5** command, with factory-default settings. See *Port 5 Settings on page SET.70* for the Port 5 settings sheets.

Make the following settings using the **SET P 5** command:

➤   IPADDR := IP Address assigned by network administrator

➤   SUBNETM := Subnet mask assigned by network administrator

➤   DEFRTR := Default router IP Address assigned by network administrator

➤   NETMODE := SWITCHED (available with dual Ethernet ports)

➤   ETELNET := Y

➤   EHTTP := Y

Leave all other settings at their default values.

NOTE: Telnet and the web server work with other NETMODE settings also, but NETMODE := SWITCHED is easiest to begin communications. The relay hides setting NETMODE when equipped with a single Ethernet port.

Connect an Ethernet cable between your PC or a network switch and any Ethernet port on the relay. Verify that the amber Link LED illuminates on the connected relay port. Many computers and most Ethernet switches support auto crossover, so nearly any CAT5 Ethernet cable with RJ45 connectors, such as an SEL-C627, will work. When the computer does not support auto crossover, use a crossover cable, such as an SEL-C628. For fiber-optic Ethernet ports use an SEL-C807 62.5-µm fiber-optic cable with LC connectors. If your relay is equipped with dual Ethernet ports, connect to either port. Use a Telnet application or QuickSet on the host PC to communicate with the relay. To terminate a Telnet session, use the command **EXI <Enter>** from any access level.

Launch a web browser and navigate to http://IPADDR, where IPADDR is the Port 5 IPADDR setting. To terminate the session, close the web browser.

Using Redundant Ethernet Ports

The SEL-651R-2 is optionally equipped with two 10/100BASE-T copper or 100BASE-FX fiber-optic Ethernet ports. Use two Ethernet ports in redundant network architectures, or force the relay to use a single Ethernet port even though it is equipped with two ports.

Redundant Ethernet Network Using SWITCHED Mode

Make Port 5 setting NETMODE := SWITCHED to activate the internal Ethernet switch. The internal switch connects a single Ethernet stack inside the relay to the two external Ethernet ports. The combination of relay and internal switch operate the same as if a single Ethernet port on a relay were connected to an external unmanaged Ethernet switch. Use the internal switch to create "self-healing rings" as shown in *Figure 10.1*.

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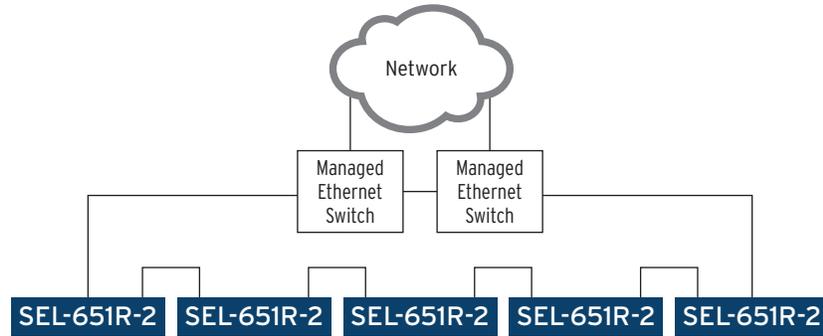
Figure 10.1   Self-Healing Ring Using Internal Ethernet Switch

Using this topology the network can still connect to any relay even if another relay, cable, or switch fails. The external managed network switches select which of the two relay Ethernet ports are used for what purpose. That selection is invisible to the relay and does not require special relay configuration (other than making setting NETMODE = SWITCHED).

Redundant Ethernet Network Using FAILOVER Mode

Make the following settings in Port 5 to configure the relay for FAILOVER mode.

➤ NETMODE := FAILOVER

➤ FTIME := desired timeout for the active port before failover to the backup port (0.10–65.00 seconds and OFF)

➤ NETPORT := the preferred network interface (A for Port 5A, B for Port 5B)

Use the internal failover switch to connect the relay to redundant networks as shown in *Figure 10.2*.
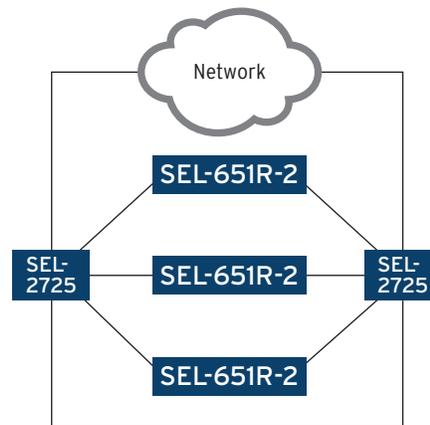
Figure 10.2   Failover Network Topology

On startup the relay communicates using the primary network interface selected by the NETPORT setting. If the relay detects a link failure on the primary interface and the link status on the standby interface is healthy, the relay activates the standby network interface after time FTIME. If the link status on the primary interface returns to normal before time FTIME, the failover timer resets and operation continues on the primary network interface.

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Setting FTIME = OFF allows fast port switching (with no intentional delay). Fast port switching can occur within one processing interval (typically 4 to 5 ms) and can help with IEC 61850 GOOSE performance.

After failover, while communicating via the standby interface, if the relay detects a link failure on the standby interface and the link status on the primary interface is healthy, the relay activates the primary network interface after time FTIME. The choice of active port is re-evaluated after settings are changed or the relay is restarted.

Network Connection Using Fixed Connection Mode

Force the relay to use a single Ethernet port even when it is equipped with two Ethernet ports by making settings NETMODE = FIXED. When NETMODE = FIXED, only the interface selected by NETPORT is active. The other interface is disabled.

Ethernet Status Relay Word Bits

The SEL-651R-2 Ethernet status is available through the Relay Word bits shown in *Table 10.2*.

Table 10.2 Ethernet Status Indicators

Relay Word Bit	Available by Relay Model	Description	Valid When
LINK5	Single Ethernet	Asserts when a valid Ethernet link is detected on Port 5	Port 5 setting EPORT := Y
LINK5A	Dual Ethernet	Asserts when a valid Ethernet link is detected on Port 5A	Port 5 setting EPORT := Y
LINK5B	Dual Ethernet	Asserts when a valid Ethernet link is detected on Port 5B	Port 5 setting EPORT := Y
LNKFAIL	Single or Dual Ethernet	Asserts when the active port is down	Port 5 setting EPORT := Y
P5ASEL	Dual Ethernet	Asserts when Port 5A is selected	Port 5 setting NETMODE := FAILOVER
P5BSEL	Dual Ethernet	Asserts when Port 5B is selected	Port 5 setting NETMODE := FAILOVER

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Hardware Handshaking

All EIA-232 serial ports support RTS/CTS hardware handshaking. RTS/CTS handshaking is not supported on the EIA-485 Serial Port 1.

To enable hardware handshaking, use the **SET P** command (or front-panel **SET** pushbutton) to set RTSCTS := Y. Disable hardware handshaking by setting RTSCTS := N.

➤ If RTSCTS := N, the relay permanently asserts the RTS line.

➤ If RTSCTS := Y, the relay deasserts RTS when it is unable to receive characters.

➤ If RTSCTS := Y, the relay does not send characters until the CTS input is asserted.

Communications Port Pinouts

Figure 10.3 and *Table 10.3–Table 10.5* show the functions of the pins and terminals of the serial ports.

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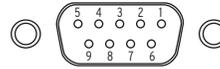
Figure 10.3   DB-9 Connector Pinout for EIA-232 Serial Ports

Table 10.3   Pinout Functions for EIA-232 Serial Ports 2, 3, and F

Pin	Port 2	Port 3	Port F
1	N/C or +5 Vdc[a]	N/C or +5 Vdc[a]	N/C
2	RXD	RXD	RXD
3	TXD	TXD	TXD
4	+IRIG-B	N/C	N/C
5, 9	GND	GND	GND
6	–IRIG-B	N/C	N/C
7	RTS	RTS	RTS
8	CTS	CTS	CTS

[a] See Serial Port Voltage Jumpers on page 2.53.

Table 10.4   Terminal Functions for EIA-485 Serial Port 1

Terminal	Function
1	+TX
2	–TX
3	+RX
4	–RX
5	SHIELD

Table 10.5   Serial Communications Port Pin/Terminal Function Definitions

Pin Function	Definition
N/C	No Connection
+5 Vdc (0.5 A combined limit)	5 Vdc Power Connection
RXD, RX	Receive Data
TXD, TX	Transmit Data
IRIG-B	IRIG-B Time-Code Input
GND	Ground
SHIELD	Shielded Ground
RTS	Request To Send
CTS	Clear To Send

IRIG-B

Demodulated IRIG-B time code can be input into the IRIG-B BNC connector on the SEL-651R-2 rear panel (see *Figure 2.5* and *Figure 2.9*). Connect the IRIG-B BNC input to a high-quality time source such as the SEL-2401 Satellite Synchronized Clock to enable microsecond accurate time synchronization and to enable the SEL-651R-2 to create C37.118 Synchrophasors (see *Appendix J: Synchrophasors*).

Demodulated IRIG-B time code can be input into Serial Port 2 (pin functions +IRIG-B and –IRIG-B; see *Table 10.3*). This is handled adeptly by connecting Serial Port 2 of the SEL-651R-2 to an SEL-2032 by using an SEL-C273A cable (see cable diagrams that follow in this section).

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If IRIG-B is input at both Serial Port 2 and the IRIG-B BNC connector, the relay uses the IRIG-B time code received on the BNC connector.

Simple Network Time Protocol (SNTP) can act as a reduced-accuracy backup to IRIG-B. See *Simple Network Time Protocol (SNTP)* for more information on configuring SNTP.

Relay Word Bit TIRIG

TIRIG asserts when the relay time is based on an IRIG-B time source. If the relay is not synchronized to a connected IRIG-B time source, TIRIG deasserts. See *Configuring High-Accuracy Timekeeping on page J.21* for more details on TIRIG.

Relay Word Bit TSOK

TSOK asserts to indicate that the IRIG-B time source is of sufficient accuracy for synchrophasor measurement (see *Appendix J: Synchrophasors*).

Communications Cables

The following cable diagrams show several types of communications cables that connect the SEL-651R-2 to other devices. These and other cables are available from SEL. Contact the factory for more information.

The 1300 nm fiber-optic Ethernet ports are designed for 62.5 μm fiber with LC connectors. The total link budget is 11 dB. See the *Fiber-Optic Products and Applications Data Sheet* at selinc.com for instructions on how to calculate fiber system losses.

SEL-651R-2 to Computer

Cable SEL-C234

SEL-651R-2
9-Pin Male
"D" Subconnector

*DTE Device
9-Pin Female
"D" Subconnector

Pin Func.	Pin #		Pin #	Pin Func.
RXD	2	———————————	3	TXD
TXD	3	———————————	2	RXD
GND	5	———————————	5	GND
CTS	8	———————————	8	CTS
			7	RTS
			1	DCD
			4	DTR
			6	DSR

*DTE = Data Terminal Equipment (Computer, Terminal, etc.)

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Cable SEL-C227A

<u>SEL-651R-2</u>   <u>*DTE Device</u>
9-Pin Male   25-Pin Female
"D" Subconnector   "D" Subconnector

Pin   Pin
<u>Func.</u>   <u>Pin #</u>   <u>Pin #</u>   <u>Func.</u>
GND   5 ————————————————————— 7   GND
TXD   3 ————————————————————— 3   RXD
RXD   2 ————————————————————— 2   TXD
GND   9 ————————————————————— 1   GND
CTS   8 —————————————————┐ 4   RTS
                           └ 5   CTS
                           ┌ 6   DSR
                           ├ 8   DCD
                           └ 20   DTR

*DTE = Data Terminal Equipment (Computer, Terminal, etc.)

Cable SEL-C664

<u>SEL-651R-2</u>   <u>Computer</u>
USB "B"   USB "A"
Connector   Connector

SEL-651R-2 to Network

Cable SEL-C627 (straight-through)
Cable SEL-C628 (crossover)

<u>SEL-651R-2</u>   <u>Computer or Switch</u>
Ethernet RJ45   Ethernet RJ45
Connector   Connector

Cable SEL-C807

<u>SEL-651R-2 </u>   <u>Computer or Switch</u>
Ethernet LC   Ethernet LC
Fiber-Optic Connector   Fiber-Optic Connector
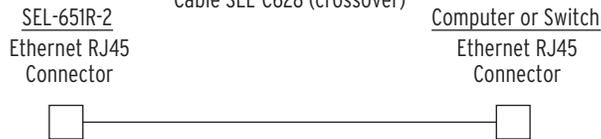
SEL-651R-2 to Modem

Cable SEL-C222

<u>SEL-651R-2</u>   <u>**DCE Device</u>
9-Pin Male   25-Pin Female
"D" Subconnector   "D" Subconnector

Pin   Pin
<u>Func.</u>   <u>Pin #</u>   <u>Pin #</u>   <u>Func.</u>
GND   5 ————————————————————— 7   GND
TXD   3 ————————————————————— 2   TXD (IN)
RTS   7 ————————————————————— 20   DTR (IN)
RXD   2 ————————————————————— 3   RXD (OUT)
CTS   8 ————————————————————— 8   CD (OUT)
GND   9 ————————————————————— 1   GND
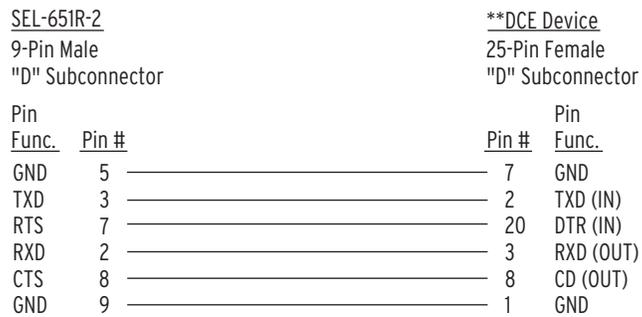
**DCE = Data Communications Equipment (Modem, etc.)

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SEL-651R-2 to SEL-3530-4 RTAC

Cable SEL-C273A

SEL-3530-4 RTAC   SEL-651R-2
9-Pin Male   9-Pin Male
"D" Subconnector   "D" Subconnector

Pin   Pin
Func.   Pin #   Pin #   Func.
RXD   2 ————————————————————————————— 3   TXD
TXD   3 ————————————————————————————— 2   RXD
IRIG+   4 ————————————————————————————— 4   IRIG+
GND   5 ————————————————————————————— 5   GND
IRIG-   6 ————————————————————————————— 6   IRIG-
RTS   7 ————————————————————————————— 8   CTS
CTS   8 ————————————————————————————— 7   RTS

SEL-651R-2 to SEL Communications Processor or SEL-2100

Cable SEL-C273A

SEL Communications
Processors and SEL-2100   SEL-651R-2
9-Pin Male   9-Pin Male
"D" Subconnector   "D" Subconnector

Pin   Pin
Func.   Pin #   Pin #   Func.
RXD   2 ————————————————————————————— 3   TXD
TXD   3 ————————————————————————————— 2   RXD
IRIG+   4 ————————————————————————————— 4   IRIG+
GND   5 ————————————————————————————— 5   GND
IRIG-   6 ————————————————————————————— 6   IRIG-
RTS   7 ————————————————————————————— 8   CTS
CTS   8 ————————————————————————————— 7   RTS

For long-distance communications as far as 500 meters and for electrical isolation of communications ports, use the SEL-2800 family of Fiber-Optic Transceivers. For IRIG-B connections and cable details, refer to the instruction manuals for the SEL-2407 Satellite-Synchronized Clock, SEL-2401 Satellite-Synchronized Clock, or other clocks. Contact SEL for more details on these devices.

Communications Protocols

The SEL-651R-2 supports many communications protocols, as shown in *Table 10.6*.

Table 10.6 Supported SEL-651R-2 Communications Protocols (Sheet 1 of 2)

	Port 1 EIA-485	Port 2 EIA-232	Port 3 EIA-232	Port 4, F EIA-232	USB	5, 5A, 5B Ethernet	Section
DNP3 L2	X	X	X	X		X	*Appendix E*
IEC 61850						X[a]	*Appendix L*
Modbus	X	X	X			X	*Appendix K*
FTP						X	*Section 10*

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Table 10.6 Supported SEL-651R-2 Communications Protocols (Sheet 2 of 2)

	Port 1 EIA-485	Port 2 EIA-232	Port 3 EIA-232	Port 4, F EIA-232	USB	5, 5A, 5B Ethernet	Section
Telnet						X	*Section 10*
Web Server (HTTP)						X	*Section 10*
C37.118 Synchrophasors	X	X	X	X		X	*Appendix J*
SNTP						X	*Section 10*
SEL ASCII and Compressed ASCII	X	X	X	X	X	Telnet	*Section 10, Appendix C*
SEL Fast Operate	X	X	X	X		Telnet	*Appendix I*
Other SEL Fast Message (Meter, SER,...)	X	X	X	X	X	Telnet	*Appendix I, Appendix H*
SEL MIRRORED BITS	X	X	X	X			*Appendix D*

ª Not available with single copper Ethernet port.

SEL ASCII, Compressed ASCII, and Fast protocols are available when the serial port PROTO setting is SEL, or when using Telnet.

Session Limits

The SEL-651R-2 supports multiple simultaneous sessions of many of the protocols listed in *Table 10.6*. The number of allowed protocol sessions depends on what other protocols are enabled, as shown in *Table 10.7*.

Table 10.7 Protocol Session Limits

Protocol	Sessions Supportedª
DNP3	The relay supports six total DNP sessions (combined serial and Ethernet sessions).
IEC 61850	The relay supports six simultaneous sessions of MMS.
Modbus	The relay supports three total Modbus sessions (combined serial and Ethernet). No Port 5 Ethernet Modbus sessions can take place (Port 5 Ethernet Modbus setting EMODBUS must remain EMODBUS := 0) if more than three Ethernet DNP sessions are enabled (Port 5 Ethernet DNP setting EDNP > 3).
FTP	The relay supports one session of File Transfer Protocol on Port 5.
Telnet	The number of available simultaneous Telnet sessions depends on Port 5 relay settings E61850, EHTTP (read-only web server), EDNP (DNP over Ethernet), and EMODBUS (Modbus TCP) as follows: ➤ When Port 5 setting E61850 = Nᵇ, the relay supports three simultaneous Telnet sessions. ➤ When Port 5 settings E61850 = Y, EHTTP = N, EDNP = 0, and EMODBUS = 0, the relay supports three simultaneous Telnet sessions. ➤ When Port 5 settings E61850 = Y, EHTTP = Y, EDNP = 0, and EMODBUS = 0, the relay supports two simultaneous Telnet sessions. ➤ When Port 5 settings E61850 = Y, EHTTP = N, and one or both of EDNP and EMODBUS are greater than 0, the relay supports two simultaneous Telnet sessions. ➤ When Port 5 settings E61850 = Y, EHTTP = Y, and one or both of EDNP > 0, EMODBUS > 0, the relay supports one Telnet session.
Web Server (HTTP)	The relay supports three simultaneous web server sessions.
C37.118 Synchrophasors	The relay supports two C37.118 synchrophasor sessions on Port 5 if Port 5 setting E61850 = Nᵇ. When Port 5 setting E61850 = Y, the relay supports one C37.118 synchrophasor session on Port 5.
SNTP	The relay supports one session of SNTP on Port 5. Some operation modes of SNTP allow the relay to synchronize to one of multiple NTP servers.

ª When properly configured (enable settings, IP addresses, etc.).
ᵇ Recloser controls ordered without IEC 61850 are treated as if E61850 = N.

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SEL Fast Meter Protocol

SEL Fast Meter protocol supports binary messages to transfer metering and control messages. The protocol is described in *Appendix I: Configuration, Fast Meter, and Fast Operate Commands*.

SEL Compressed ASCII Protocol

SEL Compressed ASCII protocol provides compressed versions of some of the relay ASCII commands. The protocol is described in *Appendix C: Compressed ASCII Commands*.

SEL Fast Sequential Events Recorder (SER) Protocol

SEL Fast Sequential Events Recorder (SER) Protocol, also known as SEL Unsolicited Sequential Events Recorder, provides SER events to an automated data collection system. SEL Fast SER Protocol is available on any serial or Ethernet port. The protocol is described in *Appendix H: Fast SER Protocol*.

Distributed Network Protocol (DNP3)

The relay provides Distributed Network Protocol (DNP3) slave support. DNP is described in *Appendix E: DNP3 Communications*.

Modbus Protocol

The relay provides Modbus protocol as described in *Appendix K: Modbus RTU and TCP Communications*.

MIRRORED BITS Communications

The SEL-651R-2 supports MIRRORED BITS relay-to-relay communications on two ports simultaneously (see *Appendix D: MIRRORED BITS Communications*).

IEEE C37.118 Synchrophasor Protocol

The relay supports the C37.118 protocol at as many as 60 messages per second as described in *Appendix J: Synchrophasors*.

IEC 61850 Protocol

The relay supports IEC 61850 protocol, including GOOSE, as described in *Appendix L: IEC 61850*. The IEC 61850 protocol is only available on relays with two copper Ethernet ports, or with one or two fiber copper Ethernet ports.

Simple Network Time Protocol (SNTP)

When Port 5 setting ESNTP is not OFF, the relay internal clock conditionally synchronizes to the time of day served by a Network Time Protocol (NTP) server. The relay uses a simplified version of NTP called the Simple Network Time Protocol (SNTP). SNTP is not as accurate as IRIG-B (see *Configuring High-Accuracy Timekeeping on page J.21*). The relay can use SNTP as a less accurate primary time source, or as a backup to the higher accuracy IRIG-B time source.

SNTP as Primary or Backup Time Source

If an IRIG-B time source is connected and either Relay Word bits TSOK or TIRIG assert, then the relay synchronizes the internal time-of-day clock to the incoming IRIG-B time-code signal, even if SNTP is configured in the relay and an NTP server is available. If the IRIG-B source is disconnected (if both TSOK and TIRIG deassert) then the relay synchronizes the internal time-of-day clock to the NTP server if available. In this way an NTP server acts as either the primary time source, or as a backup time source to the more accurate IRIG-B time source.

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Creating an NTP Server

Three SEL application notes, available from the SEL website, describe how to create an NTP server.

AN2009-10: Using an SEL-2401, SEL-2404, or SEL-2407® to Serve NTP Via the SEL-3530 RTAC

AN2009-38: Using SEL Satellite-Synchronized Clocks With the SEL-3332 or SEL-3354 to Output NTP

AN2010-03: Using an SEL-2401, SEL-2404, or SEL-2407® to Create a Stratum 1 Linux® NTP Server

Configuring SNTP Client in the Relay

To enable SNTP in the relay make Port 5 setting ESNTP = UNICAST, MANYCAST, or BROADCAST. *Table 10.8* shows each setting associated with SNTP.

Table 10.8   Settings Associated With SNTP

Setting	Range	Description
ESNTP	UNICAST, MANYCAST, BROADCAST	Selects the mode of operation of SNTP. See descriptions in *SNTP Operation Modes*.
SNTPPSIP	Valid IP Address	Selects primary NTP server when ENSTP = UNICAST, or broadcast address when ESNTP = MANYCAST or BROADCAST.
SNTPPSIB	Valid IP Address	Selects backup NTP server when ESNTP = UNICAST.
SNTPPORT	1–65534	Ethernet port used by SNTP. Leave at default value unless otherwise required.
SNTPRATE	15–3600 seconds	Determines the rate at which the relay asks for updated time from the NTP server when ESNTP = UNICAST or MANYCAST. Determines the time the relay will wait for an NTP broadcast when ENSTP = BROADCAST.
SNTPTO	5–20 seconds	Determines the time the relay will wait for the NTP master to respond when ENSTP = UNICAST or MANYCAST.

SNTP Operation Modes

The following sections explain the setting associated with each SNTP operation mode (UNICAST, MANYCAST, and BROADCAST).

ESNTP := UNICAST

In unicast mode of operation the SNTP client in the relay requests time updates from the primary (IP address setting SNTPPSIP) or backup (IP address setting SNTPBSIP) NTP server at a rate defined by setting SNTPRATE. If the NTP server does not respond within the period defined by setting SNTPTO then the relay tries the other SNTP server. When the relay successfully synchronizes to the primary NTP time server, Relay Word bit TSNTPP asserts. When the relay successfully synchronizes to the backup NTP time server, Relay Word bit TSNTPB asserts.

ESNTP := MANYCAST

In manycast mode of operation the relay initially sends an NTP request to the broadcast address contained in setting SNTPPSIP. The relay continues to broadcast requests at a rate defined by setting SNTPRATE. When a server replies, the relay considers that server to be the primary NTP server and switches to UNICAST mode, asserts Relay Word bit TSNTPP, and thereafter

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requests updates from the primary server. If the NTP server stops responding for time SNTPTO, the relay deasserts TSNTPP and begins to broadcast requests again until the original or another server responds.

ESNTP := BROADCAST

If setting SNTPPSIP = 0.0.0.0 while setting ESNTP = BROADCAST, the relay will listen for and synchronize to any broadcasting NTP server. If setting SNTPPSIP is set to a specific IP address while setting ESNTP = BROADCAST, then the relay will listen for and synchronize to only NTP server broadcasts from that address. When synchronized the relay asserts Relay Word bit TSNTPP. Relay Word bit TSNTPP deasserts if the relay does not receive a valid broadcast within five seconds after the period defined by setting SNTPRATE.

SNTP Accuracy Considerations

SNTP time synchronization accuracy is limited by the accuracy of the SNTP Server and by the networking environment. The highest degree of SNTP time synchronization can be achieved by minimizing the number of switches and routers between the SNTP Server and the SEL-651R-2. Network monitoring software can also be used to ensure average and worst-case network bandwidth utilization is moderate.

When installed on a network configured with one Ethernet switch between the SEL-651R-2 and the SNTP Server, and when using ESNTP = UNICAST or MANYCAST, the relay time synchronization error with the SNTP server is typically less than ±1 millisecond.

File Transfer Protocol (FTP) and MMS File Transfer

File Transfer Protocol (FTP) is a standard protocol for exchanging files between computers over a TCP/IP network. The SEL-651R-2 operates as an FTP server, presenting files to FTP clients. The recloser control supports one FTP session at a time. Requests to establish additional FTP sessions are denied.

Manufacturing Messaging Specification (MMS) is used in IEC 61850 applications and provides services for the transfer of real-time data, including files, within a substation LAN.

File Structure

The file structure is organized as a directory and subdirectory tree similar to that used by Windows and other common operating systems. See *Virtual File Interface on page 10.24* for information on available files.

File dates within the last 12 months are displayed with month, day, hour, and minutes. Dates older than twelve months have the year, month, and day. The times are UTC.

Access Control

To log in to the FTP server, enter the value of the Port 5 setting FTPUSER as the user name in your FTP application. Enter the Level 2 password as the password in your FTP application. Note that FTP does not encrypt passwords before sending them to the server.

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MMS is enabled when Port 5 setting E61850 is set to Y. No authentication is required. MMS File Transfer is enabled when setting EMMSFS is set to Y. If MMS Authentication is enabled via the CID file, then an authenticated connection must be established via MMS for MMS file transfer to take place.

Using FTP and MMS

A free FTP application is included with most web browser software and PC operating systems. You can also obtain free or inexpensive FTP applications from the Internet. Once you have retrieved the necessary files, be sure to close the FTP connection by using the disconnect function of your FTP application or completely closing the application. Failure to do so can cause the FTP connection to remain open, which blocks subsequent connection attempts until FTPIDLE time expires.

See *Appendix L: IEC 61850* for information about using MMS.

Using the Embedded Web Server (HTTP)

When Port 5 setting EHTTP := Y, the relay serves webpages displaying certain settings, metering, and status reports. The relay embedded web server has been optimized and tested to work with the most popular web browsers, but should work with any standard web browser. As many as three users can access the embedded web server simultaneously. Access Level 2 allows the user to upgrade firmware over the web server interface (see method three in *Appendix B: Firmware Upgrade Instructions*). Port 5 setting HTTPACC determines the maximum access level available to the web server, and its default is level 2. To begin using the embedded web server, launch your web browser and navigate to http://IPADDR, where IPADDR is the Port 5 setting IPADDR (e.g., http://192.168.1.2). The relay responds with a login screen as shown in *Figure 10.4*.
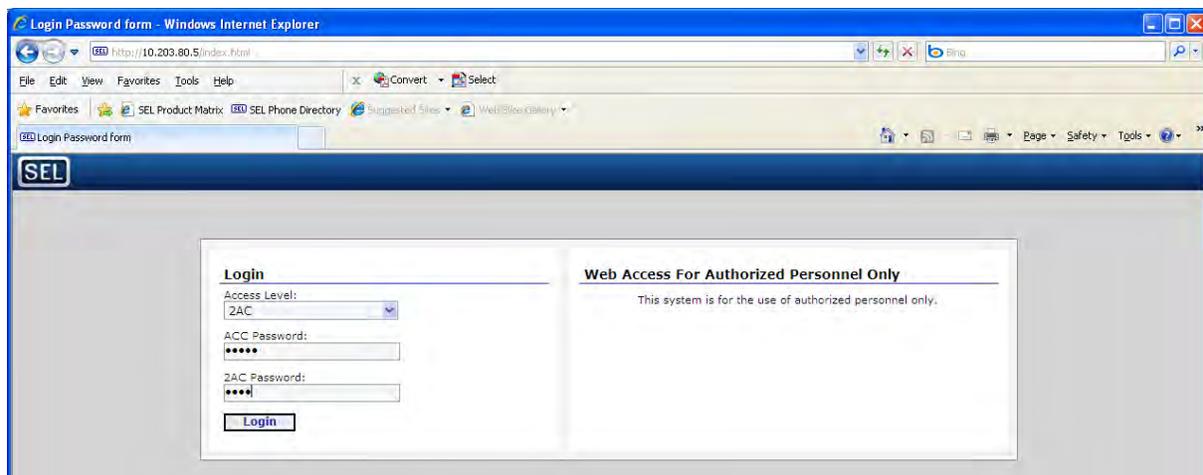
Figure 10.4   Web Server Login Screen

The HTTPACC Port 5 setting determines the access level available to the web server and defaults to Access Level 2. If HTTPACC is set to 2, Access Level 1 (ACC) or Access Level 2 (2AC) can be chosen from the Access Level drop down box. Enter the appropriate password(s) in the text box(es) below the Access Level drop down box. If 2AC is chosen, both the ACC and 2AC passwords must be entered to login, as shown in *Figure 10.4*. Note that access level passwords are not encrypted in any way by the web server when logging in. Once you have entered the correct Password(s), the relay responds with the meter display home page. While you remain logged into the relay, the webpage displays the approximate time as determined by the relay time-of-

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day clock and increments the displayed time once per second based on the clock contained in your PC. *Figure 10.5* shows an example of the Device Features screen, equivalent to the relay version command.
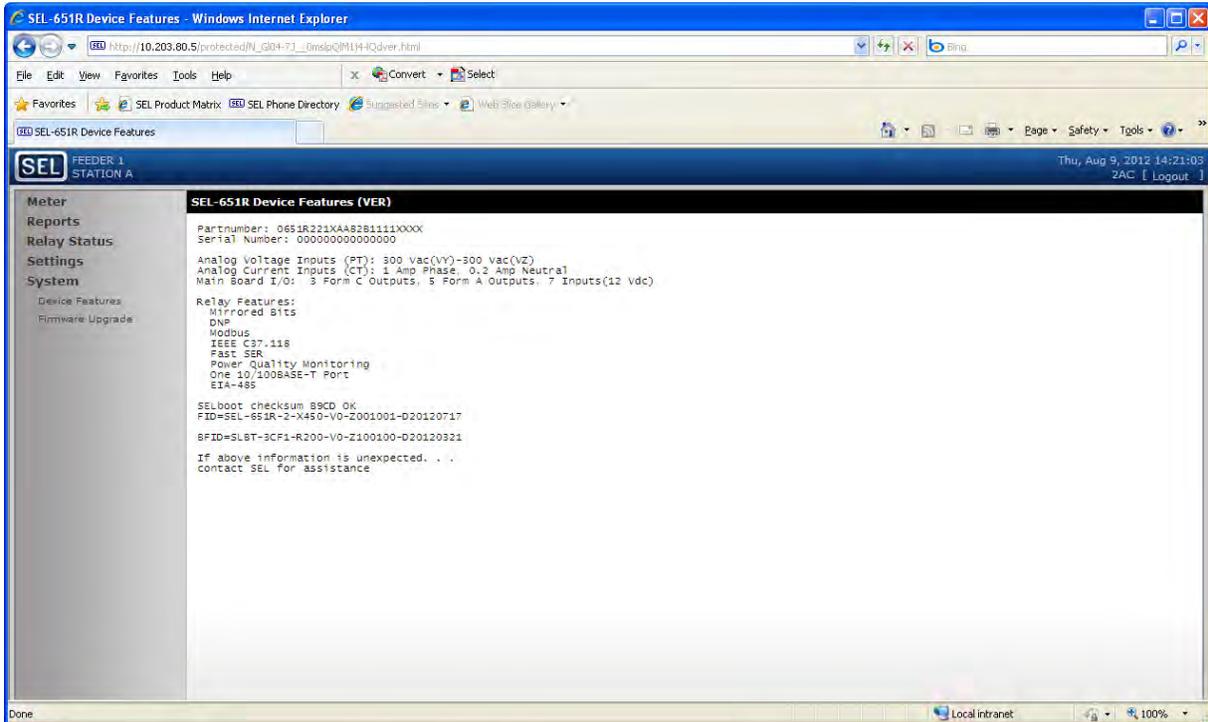
Figure 10.5   Web Server Device Features Selection

Click on any menu selection from the left pane to retrieve various reports. Some menus expand to reveal more menus, such as the **Show Settings** menu shown in *Figure 10.6*.

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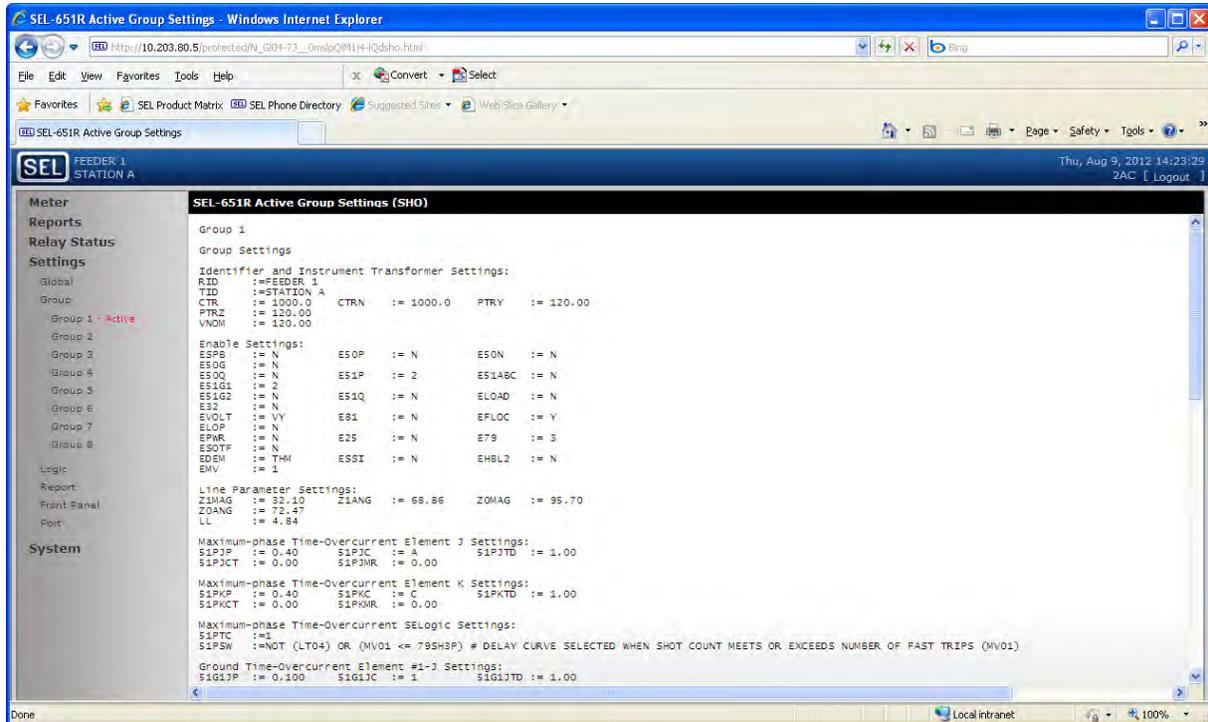
Figure 10.6   Web Server Show Settings Screen

The Meter Reports screens update automatically about every five seconds.

To log out, either close the web browser window or click on **[Logout]** in the banner bar near the top of the webpage.

SEL ASCII Protocol

SEL ASCII protocol is designed for manual and automatic communications.

All commands received by the relay must be of the form:

<command><CR>   or   <command><CRLF>

NOTE: The **<Enter>** key on most keyboards is configured to send the ASCII character 13 (^M) for a carriage return. This manual instructs you to press the **<Enter>** key after commands, which should send the proper ASCII code to the relay.

A command transmitted to the relay should consist of the command followed by either a CR (carriage return) or a CRLF (carriage return and line feed). You may truncate commands to the first three characters. For example, **HISTORY 1 <Enter>** would become **HIS 1 <Enter>**. Upper- and lowercase characters may be used without distinction, except in passwords.

Software Flow Control

The SEL-651R-2 implements XON/XOFF flow control. You can use the XON/XOFF protocol to control the relay during data transmission. When the relay receives XOFF during transmission, it pauses until it receives an XON character. If there is no message in progress when the relay receives XOFF, it blocks transmission of any message presented to its buffer. Messages will be accepted after the relay receives XON.

The relay transmits XON (ASCII hex 11) and asserts the RTS output (if hardware handshaking is enabled) when the relay input buffer drops below 25 percent full.

The relay transmits XOFF (ASCII hex 13) when the buffer is more than 75 percent full. If hardware handshaking is enabled, the relay deasserts the RTS output when the buffer is approximately 95 percent full. Automatic

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transmission sources should monitor for the XOFF character to avoid overwriting the buffer. Transmission should terminate at the end of the message in progress when XOFF is received and can resume when the relay sends XON.

The CAN character (ASCII hex 18) aborts a pending transmission. This is useful for terminating an unwanted transmission.

Control characters can be sent from most keyboards with the following keystrokes:

➤ XOFF: **<Ctrl+S>** (hold down the **<Ctrl>** key and press **S**)

➤ XON: **<Ctrl+Q>** (hold down the **<Ctrl>** key and press **Q**)

➤ CAN: **<Ctrl+X>** (hold down the **<Ctrl>** key and press **X**)

Serial Port and Telnet Session Automatic Messages

When the Telnet or serial port AUTO setting is Y, the relay sends automatic messages to indicate specific conditions. The automatic messages are described in *Table 10.9*.

Table 10.9   Serial Port Automatic Messages

Condition	Description
Power Up	The relay sends a message containing the present date and time, Relay and Terminal Identifiers, and the Access Level 0 prompt when the relay is turned on.
Event Trigger	The relay sends an event summary each time an event report is triggered (see *Section 12: Analyzing Events*).
Group Switch	The relay displays the active settings group after a group switch occurs (see *GRO Command (Display Active Settings Group Number)*).
Self-Test Warning or Failure	The relay sends a status report each time a self-test warning or failure condition is detected (see *STA Command (Relay Self-Test Status)*).

Port Access Levels

Commands can be issued to the relay via the serial port, USB port, or Telnet session to view metering values, change relay settings, etc. The available commands are listed in *Table 10.18*. The commands can be accessed only from the corresponding access level as shown in *Table 10.18*. The access levels are:

➤ Access Level 0 (the lowest access level)

➤ Access Level 1

➤ Access Level B

➤ Access Level 2 (the highest access level)

➤ Access Level C (restricted access level, should be used under direction of SEL only)

Limit Maximum Access Level or Disable Any Port

Disable any port by using the EPORT setting. For example, if EPORT := N on Port 5, then Port 5, 5A, and 5B will be nonresponsive.

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Limit the maximum allowable access level on any enabled port configured for Telnet or SEL ASCII protocols by using the MAXACC setting. For example, if MAXACC := 1 on Port 5, then the maximum access level attainable from a Telnet session on Port 5, 5A, and 5B is limited to Access Level 1. The MAXACC setting on Port 5 does not limit FTP. FTP is always able to read and write settings files even if MAXACC := 1.

For serial port sessions and Ethernet port Telnet sessions, changing a port MAXACC setting to a lower access level will cause the relay to terminate any active session(s) on that port that exceed the new MAXACC level. Any new access level attempts on the port are only granted up to the MAXACC allowed level.

For the USB port, changing the Port F MAXACC setting to a lower access level does not terminate a USB session in progress. After a **QUIT** command or timeout, any new access level attempts on the USB port are only granted up to the Port F MAXACC allowed level.

When MAXACC = 0, the port (serial or Ethernet) is available for SEL Fast Messaging and Fast Operate only.

See *Port Enable Settings (SET P n Command) on page 9.60* for more information about these and other port settings.

Access Level 0

Once ASCII communications are established with the relay, the relay sends the following prompt:

```
=
```

This is referred to as Access Level 0. Enter the **ACC** command at the Access Level 0 prompt:

```
=ACC <Enter>
```

The **ACC** command takes the relay to Access Level 1 (see *ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C)* for more detail).

Access Level 1

When the relay is in Access Level 1, the relay sends the following prompt:

```
=>
```

Commands available from Access Level 1 are shown in *Table 10.18*. For example, enter the **MET** command at the Access Level 1 prompt to view metering data:

```
=>MET <Enter>
```

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The **2AC** command allows the relay to go to Access Level 2 (see *ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C)* for more detail). Enter the **2AC** command at the Access Level 1 prompt:

```
=>2AC <Enter>
```

The **BAC** command allows the relay to go to Access Level B (see *ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C)* for more detail). Enter the **BAC** command at the Access Level 1 prompt:

```
=>BAC <Enter>
```

Access Level B

When the relay is in Access Level B, the relay sends the prompt:

```
==>
```

Commands available from Access Level B are shown in *Table 10.18*. For example, enter the **CLO** command at the Access Level B prompt to close the circuit breaker:

```
==>CLO <Enter>
```

While in Access Level B, any of the Access Level 1 commands are also available.

The ACCESSP Relay Word bit will pulse for approximately one second when the access level is increased to Access Level B or higher. The ACCESS Relay Word bit will assert and remain asserted when the access level is B or higher. When you attempt to go to Access Level B or higher, entry of an incorrect password causes the PASNVAL Relay Word bit to pulse for approximately one second. If an incorrect password is entered three consecutive times, the BADPASS Relay Word bit will pulse for approximately one second. ACCESSP, PASNVAL, and BADPASS are part of the default SELOGIC control equation for SALARM (see *Factory-Default Settings on page 9.61*).

The **2AC** command allows the relay to go to Access Level 2 (see *ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C)* for more detail). Enter the **2AC** command at the Access Level B prompt:

```
==>2AC <Enter>
```

Access Level 2

When the relay is in Access Level 2, the relay sends the prompt:

```
=>>
```

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Commands available from Access Level 2 are shown in *Table 10.18*. For example, enter the **SET** command at the Access Level 2 prompt to make relay settings:

```
=>>SET <Enter>
```

While in Access Level 2, any of the Access Level 1 and Access Level B commands are also available.

The ACCESSP Relay Word bit will pulse for approximately one second when the access level is increased to Access Level B or higher. The ACCESS Relay Word bit will assert and remain asserted when the access level is B or higher. When you attempt to go to Access Level B or higher, entry of an incorrect password causes the PASNVAL Relay Word bit to pulse for approximately one second. If an incorrect password is entered three consecutive times, the BADPASS Relay Word bit will pulse for approximately one second. ACCESSP, PASNVAL, and BADPASS are part of the default SELOGIC equation for SALARM (see *Factory-Default Settings on page 9.61*).

Access Level C

The CAL access level is intended for use by the SEL factory and SEL field service personnel to help diagnose troublesome installations. A list of commands available at the CAL level is available from SEL upon request. Do not enter the CAL access level except as directed by SEL.

The **CAL** command allows the relay to go to Access Level C (see *ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C)* for more detail). Enter the **CAL** command at the Access Level 2 prompt:

```
=>>CAL <Enter>
```

Virtual File Interface

You can retrieve and send data as files through the relay virtual file interface. Devices with embedded computers can also use the virtual file interface. When using serial ports or virtual terminal links, use the **FIL DIR** command to access the file interface. When you use a communications card, the file transfer protocol(s) supported by the card can present the file structure and send and receive files.

Send and receive files by using the following three protocols:

1. File Transfer Protocol (FTP)

2. MMS File Transfer

3. Ymodem

FTP and MMS File Structure

FTP and MMS have a two-level file structure. Files are available at the root level and subdirectories. *Table 10.10* shows the directories and their contents.

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Table 10.10   FTP and MMS Virtual File Structure

Directory	Contents
/ (Root)	CFG.TXT[a] file, CFG.XML file, ERR.TXT file and SET_61850.CID and the SETTINGS, REPORTS, DIAGNOSTICS, EVENTS, and COMTRADE[b] directories
/SETTINGS[a]	Relay settings
/REPORTS	SER, LDP, SSI, target, metering, circuit breaker, and history reports
/DIAGNOSTICS	Relay status and vector reports
/EVENTS	CEV, COMTRADE, HIF, and history reports
/COMTRADE[b]	COMTRADE events

[a] Only available in FTP file structure.
[b] The COMTRADE directory is only available in MMS file structure.

Root Directory

The root directory (/) contains files and subdirectories as shown in *Table 10.10*.

CFG.TXT File (Read-Only)

The CFG.TXT file contains general configuration information about the relay and each settings class. External support software retrieves the CFG.TXT file to interact automatically with the relay. The relay calculates a checksum, or hash code, for each settings class and lists the codes in the CFG.TXT file (see *Figure 10.7*). Calibration settings are included only when the file is read at Access Level C. Improve system security by periodically reading the CFG.TXT file and comparing the current hash codes to those in a secured copy of the file. See *Appendix M: Cybersecurity Features* for more information.

```
RELAYTYPE=0651R
FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxx
BFID=SLBT-3CF1-Rxxx-Vx-Zxxxxxx-Dxxxxxx
PARTNO=0651R221XEG8AE2123XXXX
[CLASSES]
"1","Group 1","SET_1.TXT","BC3503AE"
"2","Group 2","SET_2.TXT","399AA540"
"3","Group 3","SET_3.TXT","8344874F"
"4","Group 4","SET_4.TXT","F04D0E5D"
"5","Group 5","SET_5.TXT","E31A7A8D"
"6","Group 6","SET_6.TXT","CA3BEEAD"
"7","Group 7","SET_7.TXT","E96E8184"
"8","Group 8","SET_8.TXT","69055673"
"D1","DNP Map 1","SET_D1.TXT","F2CC8911"
"D2","DNP Map 2","SET_D2.TXT","DD7097AB"
"D3","DNP Map 3","SET_D3.TXT","ACDB00ED"
"G","Global","SET_G.TXT","4781FC7F"
"L1","Logic 1","SET_L1.TXT","9121B30A"
"L2","Logic 2","SET_L2.TXT","379B605F"
"L3","Logic 3","SET_L3.TXT","3EC8C373"
"L4","Logic 4","SET_L4.TXT","7CBFBC39"
"L5","Logic 5","SET_L5.TXT","194724C0"
"L6","Logic 6","SET_L6.TXT","6C066FC1"
"L7","Logic 7","SET_L7.TXT","FB039F0C"
"L8","Logic 8","SET_L8.TXT","AD96080B"
"M","Modbus","SET_M.TXT","16B0567D"
"P1","Port 1","SET_P1.TXT","85E70297"
"P2","Port 2","SET_P2.TXT","93AB0DF9"
"P3","Port 3","SET_P3.TXT","AFB78215"
"PF","Port F","SET_PF.TXT","FFD09259"
"P5","Port 5","SET_P5.TXT","81603DFD"
"R","Report","SET_R.TXT","2E4A7229"
"F","Front Panel","SET_F.TXT","0E341DA8"
[STORAGE]
```

Figure 10.7   CFG.TXT File

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CFG.XML File (Read-Only)

Present only in units with the Ethernet card installed, the CFG.XML file is supplementary to the CFG.TXT file. The CFG.XML file describes the IED configuration and any options such as the Ethernet port, and includes firmware identification, settings class names, and configuration file information.

ERR.TXT (Read-Only) and SET_61850.CID File

Present if ordered with the IEC 61850 protocol option. The ERR.TXT file contents is based on the most recent SET_61850.CID file written to the relay. If there were no errors, the file is empty. If errors occurred, the relay logs these errors in the ERR.TXT file. The SET_61850.CID file contains the IEC 61850 configured IED description in XML. ACSELERATOR Architect SEL-5032 Software generates and then downloads this file to the relay. See *Appendix L: IEC 61850* for more information.

Settings Directory (Only Available for FTP)

You can access the relay settings through files in the SETTINGS directory. We recommend that you use support software to access the settings files, rather than directly accessing them via other means. External settings support software reads settings from all of these files to perform its functions. The relay only allows you to write to the individual SET_*cn* files, where *c* is the settings class code and *n* is the settings instance. Except for the SET_61850 CID file, changing settings with external support software involves the following steps:

Step 1. The PC software reads the CFG.TXT and SET_ALL.TXT files from the relay.

Step 2. You modify the settings at the PC. For each settings class that you modify, the software sends a SET_*cn*.TXT file to the relay.

Step 3. The PC software reads the ERR.TXT file. If it is not empty, the relay detects errors in the SET_*cn*.TXT file.

Step 4. For any detected errors, modify the settings and send the settings until the relay accepts your settings.

Step 5. Repeat *Step 2–Step 4* for each settings class that you want to modify.

Step 6. Test and commission the relay.

SET_ALL.TXT File (Read-Only)

The SET_ALL.TXT file contains the settings for all of the settings classes in the relay. Calibration settings are included only when the file is read at Access Level C.

SET_cn.TXT Files (Read and Write)

There is a file for each instance of each setting class. *Table 10.11* summarizes the settings files. The settings class is designated by *c*, and the settings instance number is designated by *n*.

ERR.TXT (Read-Only)

The ERR.TXT file contents are based on the most recent SET_*cn*.TXT file written to the relay. If there were no errors, the file is empty. If errors occurred, the relay logs these errors in the ERR.TXT file.

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Table 10.11   Settings Directory Files

File Name	Settings Description
SET_*n*.TXT	Group; *n* in range 1–8
SET_D*n*.TXT	DNP3 remapping; *n* in range 1–3
SET_F.TXT	Front panel
SET_G.TXT	Global
SET_L*n*.TXT	Logic; *n* in range 1–8
SET_M.TXT	Modbus remapping
SET_P*n*.TXT	Port; *n* in range 1, 2, 3, 5, F
SET_R.TXT	Report
SET_ALL.TXT	All instances of all settings classes
ERR.TXT	Error log for most recently written settings file

Reports Directory (Read-Only)

Use the REPORTS directory to retrieve files that contain the reports shown in *Table 10.12*. Note that the relay provides a report file that contains the latest information each time you request the file. Each time you request a report, the relay stores its corresponding command response in the designated text file.

Table 10.12   Reports Directory Files

File Name	Description	Equivalent Command Response
BRE.TXT	Breaker Report	**BRE**
CHISTORY.TXT	Compressed ASCII History Report	**CHI**
CHISTORY_HIF.TXT[a]	Compressed HIF ASCII History Report	**CHI HIF**
HISTORY.TXT	History Report	**HIS**
HISTORY_HIF.TXT[a]	HIF History Report	**HIS HIF**
LDP.TXT	Load Profile Data	**LDP**
MET.TXT	Instantaneous Metering	**MET**
MET_D.TXT	Demand Metering	**MET D**
MET_E.TXT	Energy Metering	**MET E**
MET_H.TXT	Harmonic Metering	**MET H**
MET_HIF.TXT[a]	HIF Metering	**MET HIF**
MET_M.TXT	Max-Min Metering	**MET M**
MET_PM.TXT	Synchrophasor Metering	**MET PM**
SER. TXT	Sequence of Events	**SER**
SSI.TXT	Sag/Swell/Interruption Data	**SSI**
TAR.TXT	Status of all Relay Word bits	**TAR ROW LIST**

[a] Available only when ordered with Arc Sense technology (high-impedance fault detection).

Events Directory (Read-Only)

The relay provides history, event reports, and oscillography files in the EVENTS directory as shown in *Table 10.13*.

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Event reports are available in the following formats:

➤ Compressed SEL ASCII

➤ Binary COMTRADE format (IEEE C37.111-1999)

The size of each event report file is determined by the LER setting in effect at the time the event is triggered.

Compressed SEL ASCII event report files are generated, when requested, by storing the appropriate command response shown in *Table 10.13*. Oscillography files are generated at the time the event is triggered (see *Event Report Triggering on page 12.4*). Higher resolution oscillography is available with SEL Compressed ASCII 128 sample/cycle raw event reports and binary COMTRADE files.

COMTRADE event files are available to read as a batch. See *Batch File Access on page 10.30*.

Table 10.13   Event Directory Files

File Name	Description	Equivalent Command Response
CHISTORY.TXT[a]	Compressed ASCII History Report	**CHI**
CHISTORY_HIF.TXT[a,b]	Compressed HIF ASCII History Report	**CHI HIF**
HISTORY. TXT[a]	History Report	**HIS**
HISTORY_HIF.TXT[a,c]	HIF History Report	**HIS HIF**
C4_*nnnnn*.CEV	Compressed 4-samples/cycle ASCII filtered event report; event ID number = *nnnnn*	**CEV *nnnnn***
CHF_*nnnnn*.CEV[c]	Compressed HIF ASCII event report	**CEV HIF *nnnnn***
CR_*nnnnn*.CEV	Compressed 128-samples/cycle ASCII raw event report; event ID number = *nnnnn*	**CEV R S128 *nnnnn***
HF_*nnnnn*.CFG[b,c]	HIF COMTRADE configuration file; event ID number = *nnnnn*	N/A
HF_*nnnnn*.DAT[b,c]	HIF COMTRADE binary data file; event ID number = *nnnnn*	N/A
HF_*nnnnn*.HDR[b,c]	HIF COMTRADE header file; event ID number = *nnnnn*	N/A
HR_*nnnnn*.CFG[c]	COMTRADE configuration file; event ID number = *nnnnn*	N/A
HR_*nnnnn*.DAT[c]	COMTRADE binary data file; event ID number = *nnnnn*	N/A
HR_*nnnnn*.HDR[c]	COMTRADE header file; event ID number = *nnnnn*	N/A

[a] Also available in the Reports directory for convenience.
[b] Available in the units ordered with Arc Sense technology (high-impedance fault detection).
[c] Also available in the COMTRADE directory for MMS only.

HR_nnnnn.* (Read-Only)

The three files HR_*nnnnn*.CFG, HR_*nnnnn*.DAT, and HR_*nnnnn*.HDR shown in *Table 10.13* are used to create an event report that conforms to the COMTRADE standard. The event is an unfiltered (raw) 128 samples/cycle event. The field, *nnnnn*, corresponds to the unique event identification number displayed by the **HIS E** command. For details on event reports see *Section 12: Analyzing Events*.

HF_nnnnn.* (Read-Only)

The three files HF_*nnnnn*.CFG, HF_*nnnnn*.DAT, and HF_*nnnnn*.HDR shown in *Table 10.13* are used to create a high-impedance event report that conforms to the COMTRADE standard. The field, *nnnnn*, corresponds to the unique event identification number displayed by the **HIS HIF** command. For details on event reports see *Section 12: Analyzing Events*.

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Available File Interfaces

Diagnostics Directory (Read-Only)

Use the DIAGNOSTICS directory to retrieve files that contain the reports shown in *Table 10.14*. Each time a diagnostic report is requested the relay stores the following command response in the designated text file.

Table 10.14   Diagnostic Directory Files

File Name	Description	Equivalent Command Response
STATUS.TXT	Status report	**STA**
VEC_D.TXT	Standard vector report	**VEC D**
VEC_E.TXT	Extended vector report	**VEC E**

COMTRADE Directory (Available Only for MMS)

When using MMS file transfer, conveniently retrieve all of the COMTRADE files from the COMTRADE directory. Note that the COMTRADE files are also available in the Events directory. Refer to *Table 10.13* for all the files available in the COMTRADE directory.

Ymodem File Structure

All the files available (see *Table 10.15*) for Ymodem protocol are in the root directory. See *FIL Command on page 10.49* for a response of the **FIL DIR** command.

Table 10.15   Files Available for Ymodem Protocol (Sheet 1 of 2)

File Name	Description	Read Access Level	Write Access Level
CFG.TXT	See *Root Directory on page 10.25*	1, B, 2, C	N/A
ERR.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	N/A
SET_ALL.TXT[a]	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	N/A
SET_*n*.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_C.TXT[a]	See *Settings Directory (Only Available for FTP) on page 10.26*	C	C
SET_D*n*.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_F.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_G.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_L*n*.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_M.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_P*n*.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SET_R.TXT	See *Settings Directory (Only Available for FTP) on page 10.26*	1, B, 2, C	2, C
SWCFG.ZIP	The SWCFG.ZIP file is a compressed file used to store external support software settings.	1, B, 2, C	2, C
C4_*nnnnn*.CEV	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
CHF_*nnnnn*.CEV	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
CR_*nnnnn*.CEV	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HF_*nnnnn*.CFG	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HF_*nnnnn*.DAT	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HF_*nnnnn*.HDR	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A

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Table 10.15   Files Available for Ymodem Protocol (Sheet 2 of 2)

File Name	Description	Read Access Level	Write Access Level
HR_*nnnnn*.CFG	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HR_*nnnnn*.DAT	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HR_*nnnnn*.HDR	See *Events Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
STATUS.TXT	See *Diagnostics Directory (Read-Only) on page 10.29*	1, B, 2, C	N/A
VEC_D.TXT	See *Diagnostics Directory (Read-Only) on page 10.29*	2, C	N/A
VEC_E.TXT	See *Diagnostics Directory (Read-Only) on page 10.29*	2, C	N/A
BRE.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
CHISTORY.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
CHISTORY_HIF.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HISTORY.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
HISTORY_HIF.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
LDP.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET_D.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET_E.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET_H.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET_HIF.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET_M.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
MET_PM.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
SER.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
SSI.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A
TAR.TXT	See *Reports Directory (Read-Only) on page 10.27*	1, B, 2, C	N/A

ᵃ Calibration settings are included only when accessed at Access Level C.

SWCFG.ZIP

SWCFG.ZIP file is only available for Ymodem protocol and is not available in the FTP and MMS file structure. The SWCFG.ZIP file is a fixed name, general purpose file that can be as large as 2 MB in length. Users may store any type of data or information file they choose in this file, even if it is not a zipped file, as long as it is named SWCFG.ZIP. QuickSet uses the SWCFG.ZIP file to store template files created by the licensed version of QuickSet. The SWCFG.ZIP file is only visible in the **FIL DIR** command when a user has loaded it onto the relay.

Batch File Access

Files can be accessed as a batch by using the supported wildcard characters * or ?.

FTP and MMS Wildcard Usage

Table 10.16 shows examples using supported wildcards. Note that these wildcards may be appended to a directory path (e.g., /specified_directory/ *.txt).

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Table 10.16   FTP and MMS Wildcard Usage Examples

Usage	Description	Example	Note
*xyz	Lists all files and/or subdirectories, within a specified directory, whose names (including extension) end with *xyz*.	/*.TXT	List all files with the .TXT extension.
abc*	Lists all files and/or subdirectories, within a specified directory, whose names begin with *abc*.	/SETTINGS/SET*	List all settings files that start with SET.
mno	Lists all files and/or subdirectories, within a specified directory, whose names contain *mno*.	/EVENTS/*_100*	List all events that contain _100 in the ID number.
abc?.xyz	Lists all files, within a specified directory, whose names begin with *abc* and whose names (including extension) end with *xyz* and have any one single character following the letter *c*.	/EVENTS/C?_10007.CEV	Retrieves both the filtered and raw compressed event reports pertaining to the unique event number 10007.

Ymodem Wildcard Usage

Event, report, and diagnostic files can also be accessed as a batch by using wildcards.

NOTE: Ymodem protocol does not support wildcards for settings files.

Table 10.17   Ymodem Wildcard Usage Examples

Usage	Description	Example	Note
*xyz	Lists all files whose names (including extension) end with *xyz*.	FILE DIR MET*.TXT	Lists all of the metering files (MET.TXT, MET_D.TXT, etc.)
abc*	Lists all files whose names begin with *abc*.	FILE READ HR_10007*	Retrieves all of the three files for the COMTRADE event 10007 (HR_10007.CFG, HR_10007.DAT, and HR_10007.HDR)
mno	Lists all files whose names contain *mno*.	FILE READ *10007*	Retrieves all event files pertaining to the unique event number 10007 (including both the filtered and raw compressed event reports and all three comtrade files).
abc?.xyz	Lists all files whose names begin with *abc* and whose names (including extension) end with *xyz* and have any one single character following the letter c.	FILE READ C?_10007.CEV	Retrieves both the filtered and raw compressed event reports pertaining to the unique event number 10007.

Command Summary

Table 10.18 alphabetically lists the ASCII commands, the required access level, and the prompt at the access level. All commands available at lower access levels are also available from higher access levels.

Table 10.18 includes some commands not normally issued by operators. These commands are used during the firmware upgrade process or are used by SEL communications processors or PC software to communicate with intelligent electronic devices (IEDs) and are covered in *Appendix B: Firmware Upgrade Instructions*, *Appendix I: Configuration, Fast Meter, and Fast Operate Commands*, and *Appendix C: Compressed ASCII Commands*.

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Table 10.18 ASCII Command Summary (Sheet 1 of 6)

Command	Access Level	Prompt	Command Description
2AC	1	=>	Enter Access Level 2.
ACC	0	=	Enter Access Level 1.
BAC	1	=>	Enter Breaker Access Level (Access Level B).
BNA	0	=	Display names of status bits in the A5D1 Fast Meter Message.
BRE	1	=>	Display breaker/recloser contact wear report.
BRE R	B	==>	Reset breaker/recloser contact wear monitor.
BRE W	B	==>	Preload breaker/recloser contact wear monitor data.
BTT	B	==>	Display latest battery load test results and time remaining until next discharge test.
BTT NOW	B	==>	Force a battery test and view the results.
CAL	2	=>>	Enter Access Level C. Reserved for SEL use only.
CAS	0	=	Display Compressed ASCII configuration message.
CEV *n*	1	=>	Display event report *n* in Compressed ASCII format. Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.
CEV HIF *n*	1	=>	Display HIF event report *n* in Compressed ASCII format. Parameter *n* corresponds to the event number from the **HIS HIF** command.
CHI	1	=>	Display history data in Compressed ASCII format.
CHI HIF	1	=>	Display HIF history data in Compressed ASCII format.
CLO, CLO A, CLO B, CLO C	B	==>	Momentarily assert Relay Word bit CC3, CCA, CCB, or CCC).
COM *c*	1	=>	Show communications summary report (COM report) on MIRRORED BITS Channel *c* (*c* = A or B) using all failure records in the channel calculations.
COM *c row1*	1	=>	Show COM report for MIRRORED BITS Channel *c* using the latest *row1* failure records (*row1* = 1–255, where 1 is the most recent entry).
COM *c row1 row2*	1	=>	Show COM report for MIRRORED BITS Channel *c* using failure records *row1–row2* ([*row1* and *row2*] = 1–255).
COM *c date1*	1	=>	Show COM report for MIRRORED BITS Channel *c* using failures recorded on date *date1* (see **DAT** command for date format).
COM *c date1 date2*	1	=>	Show COM report for MIRRORED BITS Channel *c* using failures recorded between dates *date1* and *date2,* inclusive.
COM *c* C	1	=>	Clears communications records for MIRRORED BITS Channel *c* (or both channels if *c* is not specified).
COM *c* L …	1	=>	For all **COM** commands (except **COM *c* C**), **L** causes the specified COM report records to be listed after the summary.
CON *n*	B	==>	Set, clear, or pulse internal Remote Bit *n* (*n* is the Remote Bit number from 01–32). The control will respond with `CONTROL RBn:`. Reply with the following: `SRB n` (to set Remote Bit *n* (assert RB*n*)) `CRB n` (to clear Remote Bit *n* (deassert RB*n*)) `PRB n` (to pulse Remote Bit *n* (assert RB*n* for 1/4 cycle))
COP *m n*	2	=>>	Copy settings from Group *m* to Group *n*.
COP D *m n*	2	=>>	Copy DNP Map *m* to Map *n*.
COU *k*	1	=>	Show the SELOGIC counter values. Enter *k* for repeat count.
CST	1	=>	Display the recloser control status in Compressed ASCII format.
CSU *n*	1	=>	Display the event summary for event report *n* (with label lines) in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.

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Table 10.18   ASCII Command Summary (Sheet 2 of 6)

Command	Access Level	Prompt	Command Description
CSU HIF *n*	1	=>	Display the HIF event summary for event report *n* in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* corresponds to the event number from the **HIS HIF** command.
DAT	1	=>	Display the internal clock date.
DAT *date*	1	=>	Set the internal clock date to *date* (Date Format setting DATE_F = MDY, YMD, or DMY).
DNA X or T	0	=	Display ASCII names of all Relay Word bits digital I/O. Either X or T is mandatory and results are identical.
ETH	1	=>	Displays information about Ethernet port(s).
ETH C	1	=>	Clears Ethernet port sent and received packets, bytes, and error statistics.
EVE *n*	1	=>	Show event report *n* with 4 samples per cycle (*n* = 1 to highest numbered event report, where 1 is the most recent report: see **HIS** command). If *n* is omitted (**EVE** command), the most recent report is displayed.
EVE *n* **A**	1	=>	Show event report *n* with analog section only.
EVE *n* **C**	1	=>	Show event report *n* in Compressed ASCII format with 16 samples-per-cycle analog resolution and 4 samples-per-cycle digital resolution.
EVE *n* **D**	1	=>	Show event report *n* with digital section only.
EVE *n* **L**	1	=>	Show event report *n* with 32 samples per cycle (similar to **EVE** *n* **S32**).
EVE *n* **L***y*	1	=>	Show first *y* cycles of event report *n* (*y* = 1 to Global setting LER).
EVE *n* **M**	1	=>	Show event report *n* with communications section only.
EVE *n* **P**	1	=>	Show event report *n* with synchrophasor-level accuracy time adjustment.
EVE *n* **R**	1	=>	Show event report *n* in raw (unfiltered) format with 32 samples-per-cycle resolution.
EVE *n* **S***x*	1	=>	Show event report *n* with *x* samples per cycle (*x* = 4, 16, 32, or 128). Must append R parameter for S128 (**EVE S128 R**).
EVE *n* **V**	1	=>	Show event report *n* with variable scaling for analog values.
EXI	0	=	Exit active Telnet session.
FIL DIR	1	=>	Display a list of available files.
FIL READ *filename*	1	=>	Transfer settings file or event file *filename* from the relay to the PC.
FIL SHOW *filename*	1	=>	Display contents of the ASCII file *filename*.
FIL WRITE *filename*	2	=>>	Transfer settings file *filename* from the PC to the relay.
GOO	1	=>	Display GOOSE information.
GOO *k*	1	=>	Display GOOSE information *k* times.
GOO S	1	=>	Display a list of GOOSE subscriptions with their ID.
GOO S *n*	1	=>	Display GOOSE statistics for subscription ID *n*.
GOO S *n* **C**	1	=>	Clear GOOSE statistics for subscription ID *n*.
GOO S *n* **L**	1	=>	Display GOOSE statistics for subscription ID *n* including error history.
GOO S ALL	1	=>	Display GOOSE statistics for all subscriptions.
GOO S ALL C	1	=>	Clear GOOSE statistics for all subscriptions.
GOO S ALL L	1	=>	Display GOOSE statistics for all subscriptions including error history.
GRO	1	=>	Display active group number.
GRO *n*	B	==>	Change the active group to Group *n* (*n* = 1–8).

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Table 10.18 ASCII Command Summary (Sheet 3 of 6)

Command	Access Level	Prompt	Command Description
HIS	1	=>	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS *n*	1	=>	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list beginning at event *n*.
HIS C	1	=>	Clear/reset the event history and all corresponding event reports from nonvolatile memory.
HIS E	1	=>	Same as **HIS**, but events are identified with a unique number in the range 10000–65535.
HIS HIF	1	=>	Display HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF *n*	1	=>	Display *n* HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF C	1	=>	Clear/reset the HIF event history and all corresponding event reports from nonvolatile memory.
HIZ	1	=>	Display HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.
HIZ *n*	1	=>	Display *n* HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.
HIZ C	1	=>	Clear/reset the HIZ event reports from nonvolatile memory.
ID	0	=	Display the firmware id, user id, device code, part number, and configuration information.
INI HIF	2	=>>	Force HIF algorithm into initial tuning mode.
L_D	2	=>>	Prepares the relay to receive new firmware.
LDP	1	=>	Show entire Load Profile (LDP) report.
LDP *n*	1	=>	Show latest *n* rows in the LDP report (*n* = 1 to several thousand, where 1 is the most recent entry).
LDP *row1 row2*	1	=>	Show rows *row1*–*row2* in the LDP report ([*row1* and *row2*] = 1 to several thousand).
LDP *date1*	1	=>	Show all rows in the LDP report recorded on the specified date *date1* (see **DAT** command for date format).
LDP *date1 date2*	1	=>	Show all rows in the LDP report recorded between dates *date1* and *date2*, inclusive.
LDP C	1	=>	Clear the Load Profile data from memory.
LDP D	1	=>	Display the number of days of Load Profile memory capacity remaining before data over-write occurs.
LOG HIF	1	=>	Display the HIF alarm and fault calculations as a percentage of their final value.
LOG HIF *n*	1	=>	Display the *n* most recent **LOG HIF** entries.
LOG HIF C	1	=>	Clear the **LOG HIF** data from memory.
LOO *c t*	2	=>>	Set Mirrored Bits Channel *c* to loopback (*c* = A or B). The received Mirrored Bits elements are forced to default values during the loopback test; *t* specifies the loopback duration in minutes (*t* = 1–5000, default is 5).
LOO *c t* **DATA**	2	=>>	Set Mirrored Bits Channel *c* to loopback for duration *t* minutes. **DATA** allows the received Mirrored Bits elements to change during the loopback test.
LOO *c* **R**	2	=>>	Cease loopback on Mirrored Bits Channel *c* and return the channel to normal operation.
MAC	1	=>	Display Ethernet port MAC address.
MET *k*	1	=>	Display instantaneous metering data *k* times.
MET D	1	=>	Display demand and peak demand metering data.
MET E	1	=>	Display energy metering data.
MET H	1	=>	Display fundamental magnitudes, root-mean-square (rms) magnitudes, Total Harmonic Distortion, and harmonic magnitudes for the first 16 harmonics.

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Table 10.18 ASCII Command Summary (Sheet 4 of 6)

Command	Access Level	Prompt	Command Description
MET HIF *k*	1	=>	Display the HIF alarm and fault calculations as a percentage of their final value. Enter *k* for repeat count (k = 1–32767; if not specified, default is 1).
MET M	1	=>	Display maximum and minimum metering data.
MET PM *k*	1	=>	Display synchrophasor measurements (available when TSOK = logical 1). Enter *k* for repeat count.
MET PM *time*	1	=>	Display synchrophasor measurements (available when TSOK = logical 1). Enter *time* to display the synchrophasor for an exact specified time, in 24-hour format.
MET PM HIS	1	=>	Display the most recent MET PM synchrophasor report.
MET RD	1	=>	Reset demand metering data.
MET RE	1	=>	Reset energy metering data.
MET RM	1	=>	Reset maximum metering data. All values will display RESET until new maximum/minimum values are recorded.
MET RMS	1	=>	Display root-mean-square (rms) metering data.
MET RP	1	=>	Reset peak demand metering data.
OPE, OPE A, OPE B, OPE C	B	==>	Momentarily assert Relay Word bit OC3, OCA, OCB, or OCC).
PAR	2	=>>	Change the device part number. Use only under the direction of SEL.
PAS 1	2	=>>	Change the Access Level 1 password.
PAS B	2	=>>	Change the Access Level B password.
PAS 2	2	=>>	Change the Access Level 2 password.
PAS C	C	==>>	Change the Access Level C password.
PUL *n s*	B	==>	Pulse output contact OUT*n* (n = 201, 202 [all models]; 101–108 [models with extra I/O]) for *s* (1–30) seconds. Parameter OUT*n* must be specified; *s* defaults to 1 if not specified.
QUI	0	=	Reduce access level to Access Level 0 (exit relay control).
R_S	2	=>>	Restore factory-default settings and passwords and reboot the system. Use only under the direction of SEL. Only available after a settings or critical RAM failure.
SER	1	=>	Show entire Sequential Events Recorder (SER) report.
SER *n*	1	=>	Show latest *n* rows in the SER report (n = 1–1024, where 1 is the most recent entry).
SER *row1 row2*	1	=>	Show rows *row1–row2* in the SER report.
SER *date1*	1	=>	Show all rows in the SER report recorded on the specified date *date1* (see **DAT** command for date format).
SER *date1 date2*	1	=>	Show all rows in the SER report recorded between dates *date1* and *date2*, inclusive.
SER C	1	=>	Clears SER report from nonvolatile memory.
SET *n*	2	=>>	Change relay settings (overcurrent, reclosing, timers, etc.) for Group *n* (n = 1–8; if not specified, default is the active settings group).
SET D *n*	2	=>>	Change DNP Map *n* settings (n = 1, 2, or 3).
SET F	2	=>>	Change Front-Panel settings.
SET G	2	=>>	Change Global settings.
SET L *n*	2	=>>	Change SELOGIC control equation settings for Group *n* (n = 1–8; if not specified, default is the active settings group).
SET M	2	=>>	Change Modbus settings.
SET P *p*	2	=>>	Change Port settings for Serial Port *p* (p = 1, 2, 3, F, or 5; if not specified, default is the active port).
SET R	2	=>>	Change SER and LDP Recorder settings.

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Table 10.18 ASCII Command Summary (Sheet 5 of 6)

Command	Access Level	Prompt	Command Description
SET … *name*	2	=>>	For all **SET** commands, jump ahead to specific setting by entering setting name.
SET … TERSE	2	=>>	For all **SET** commands, the **TERSE** command disables the automatic **SHO** command after settings entry.
SHO *n*	1	=>	Show relay settings (overcurrent, reclosing, timers, etc.) for Group *n* (*n* = 1–8; if not specified, default is active settings group).
SHO D *n*	1	=>	Show DNP Map *n* settings (*n* = 1, 2, or 3).
SHO F	1	=>	Show Front-Panel settings.
SHO G	1	=>	Show Global settings.
SHO L *n*	1	=>	Show SELOGIC control equation settings for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SHO M	1	=>	Show Modbus settings.
SHO P *p*	1	=>	Show Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).
SHO R	1	=>	Show SER and LDP Recorder settings.
SHO … *name*	1	=>	For all **SHO** commands, jump ahead to specific setting by entering setting name.
SNS	0	=	Display the Fast Message name string of the SER settings.
SSI	1	=>	Show entire Voltage Sag/Swell/Interruption (SSI) report.
SSI *n*	1	=>	Show latest *n* rows in SSI report (*n* = 1 to several thousand, where 1 is the most recent entry).
SSI *row1 row2*	1	=>	Show rows *row1–row2* in SSI report.
SSI *date1*	1	=>	Show all rows in SSI report recorded on the specified date *date1* (see **DAT** command for date format).
SSI *date1 date2*	1	=>	Show all rows in SSI report recorded between dates *date1* and *date2*, inclusive.
SSI C	1	=>	Clears SSI report from nonvolatile memory.
SSI R	1	=>	Reset the VSSI recorder logic and clear the Vbase value.
SSI T	1	=>	Trigger the SSI recorder.
STA *k*	1	=>	Display the recloser control self-test information *k* times (*k* = 1–32767; if not specified, default is 1).
STA C	2	=>>	Clear status warning or failure and reboot the recloser control.
STA S	1	=>	Display the memory and execution utilization for the SELOGIC control equations.
SUM HIF *n*	1	=>	Display the HIF summary message for event *n*.
TAR	1	=>	Display Relay Word row 0 or last displayed target row.
TAR *n k*	1	=>	Display Relay Word row number *n*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).
TAR *name k*	1	=>	Display Relay Word row containing *name*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).
TAR LIST	1	=>	Shows all the Relay Word bits in all of the rows.
TAR R	1	=>	Reset front-panel tripping targets.
TAR ROW …	1	=>	Shows the Relay Word row number at the start of each line, with other selected **TAR** commands as described above, such as *n*, *name*, *k*, and **LIST**.
TES DB	B	==>	Display the present status of digital and analog overrides.
TES DB A *name value*	B	==>	Override analog label *name* with *value* in communications interface.

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Table 10.18 ASCII Command Summary (Sheet 6 of 6)

Command	Access Level	Prompt	Command Description
TES DB A *row_x value*	B	==>	Override all Relay Word bits in Relay Word row number *row_x* with *value*.
TES DB D *name value*	B	==>	Override Relay Word bit *name* with *value* in communications interface, where *value* = 0 or 1.
TES DB *name* **OFF**	B	==>	Clear (analog or digital) override for element *name*.
TES DB OFF	B	==>	Clear all analog and digital overrides.
TIM	1	=>	Display the present internal clock time.
TIM *hh:mm*	1	=>	Set the internal clock to *hh:mm*.
TIM *hh:mm:ss*	1	=>	Set the internal clock to *hh:mm:ss*.
TIM Q	1	=>	Display time statistics.
TIM DST	1	=>	Display daylight-saving time information.
TRI	1	=>	Trigger event report data capture.
TRI *time*	1	=>	Trigger an event report data capture at specified *time*.
TRI HIF	1	=>	Trigger an HIF event report data capture. Only available in recloser controls that support Arc Sense technology.
TRI STA	1	=>	Display the status of a previous **TRI** *time* command.
VEC D	2	=>>	Display the standard Vector Report.
VEC E	2	=>>	Display the Extended Vector Report.
VER	1	=>	Display information about the configuration of the recloser control.

The recloser control responds with `Invalid Access Level` if a command is entered from an access level lower than the specified access level for the command. The recloser control responds with `Invalid Command` to commands not listed above or entered incorrectly.

Many of the command responses display the following header at the beginning:

```
[RID Setting]                    Date: mm/dd/yyyy  Time: hh:mm:ss.sss
[TID Setting]                    Time Source: external
```

The definitions follow:

[RID Setting]: This is the RID (Relay Identifier) setting. The recloser control is shipped with the default setting RID = FEEDER 1 (see *Identifier Labels (Group Settings) on page 9.40*).

[TID Setting]: This is the TID (Terminal Identifier) setting. The recloser control is shipped with the default setting TID = STATION A (see *Identifier Labels (Group Settings) on page 9.40*).

Date: This is the date when the command response was given, except for recloser control response to the **EVE** command (Event), when it is the date the event occurred. You can modify the date display format (Month/Day/Year, Year/Month/Day, or Day/Month/Year) by changing the DATE_F Global setting.

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[RID Setting]:   This is the RID (Relay Identifier) setting. The recloser control is shipped with the default setting RID = FEEDER 1 (see *Identifier Labels (Group Settings) on page 9.40*).

Time: This is the time when the command response was given, except for recloser control response to the **EVE** command, when it is the time the event occurred.

Time Source: This is internal if no time-code input is attached and external if an input is attached.

Command Explanations

ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C)

The **ACC**, **BAC**, **2AC**, and **CAL** commands provide entry to the multiple access levels. Different commands are available at the different access levels as shown in *Table 10.18*. Commands **ACC**, **BAC**, **2AC**, and **CAL** are explained together because they operate similarly.

Command	Description
ACC	Enter Access Level 1.
BAC	Enter Breaker access level (Access Level B).
2AC	Enter Access Level 2.
CAL	Enter Access Level C. Reserved for SEL use only.

Password Requirements

Passwords are required if the main board Access jumper is *not* in place (Access jumper = OFF). Passwords are not required if the main board Access jumper is in place (Access jumper = ON). Refer to *Figure 2.48* for Access jumper information. See *PAS Command (Change Passwords)* for the list of default passwords and for more information on changing passwords.

Access Level Attempt (Password Required)

Assume the following conditions: Access jumper = OFF (not in place), Access Level = 0.

At the Access Level 0 prompt, enter the **ACC** command:

```
=ACC <Enter>
```

Because the Access jumper is not in place, the relay asks for the Access Level 1 password to be entered:

```
Password: ?
```

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The relay is shipped with the default Access Level 1 password shown in the table under *PAS Command (Change Passwords)*. At the prompt above, enter the default password and press the **<Enter>** key. The relay responds:

```
FEEDER 1                        Date: 02/02/09 Time: 08:31:10.361
STATION A
Level 1
=>
```

The => prompt indicates the relay is now in Access Level 1.

If the entered password is incorrect, the relay asks for the password again (Password: ?). If the incorrect password is entered when attempting to enter Access Level B or higher the PASNVAL Relay Word bit will pulse for approximately one second. The relay will ask as many as three times. If the requested password is incorrectly entered three times in a row, the Relay Word bit BADPASS will pulse for approximately one second. After three attempts, the relay displays an invalid access message and prevents further access attempts for 30 seconds. The PASNVAL and BADPASS Relay Word bits are part of the default SALARM SELOGIC equation (see *Factory-Default Settings on page 9.61*).

Access Level Attempt (Password Not Required)

Assume the following conditions: Access jumper = ON (in place), Access Level = 0.

At the Access Level 0 prompt, enter the **ACC** command:

```
=ACC <Enter>
```

Because the Access jumper is in place, the relay does not ask for a password; it goes directly to Access Level 1. The relay responds:

```
FEEDER 1                        Date: 03/05/09 Time: 08:31:10.361
STATION A
Level 1
=>
```

The => prompt indicates the relay is now in Access Level 1.

The recloser control pulses the ACCESSP Relay Word bit for approximately one second after a successful Level B, Level 2, or Level C access. The above two examples demonstrate how to go from Access Level 0 to Access Level 1. Refer to *Port Access Levels* for more access level examples.

BNAMES Command

The **BNA** command produces ASCII names of all relay status bits reported in the Fast Meter Data Block (A5D1) message in Compressed ASCII format (see *Appendix I: Configuration, Fast Meter, and Fast Operate Commands*).

Command	Description	Access Level
BNA	Display names of status bits in the A5D1 Fast Meter Message.	0

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BRE Command (Breaker Monitor Data)

Use the **BRE** command to view the breaker monitor report.

Command	Description	Access Level
BRE	Display breaker/recloser contact wear report.	1
BRE W	Preload breaker/recloser contact wear monitor data.	B
BRE R	Reset breaker/recloser contact wear monitor.	B

```
=>BRE <Enter>

FEEDER 1                               Date: 08/29/2003  Time: 08:00:00.000
STATION A                              Time Source: internal

                           A           B           C           G
Internal Trip Counter      14          7           10
Internal Current (kA)      32.4        18.6        22.6

External Trip Counter      2           1           2
External Current (kA)      0.8         0.6         0.7

Percent Wear               22          28          25

Involved Phase Counter     10          5           8           3

LAST RESET 02/12/2003 09:25:14
=>
```

See *Breaker/Recloser Contact Wear Monitor on page 8.23* for further details on the breaker monitor.

BRE W (Preload Breaker Wear)

Use the **BRE W** command to preload breaker monitor data.

Following is a sample terminal display when preloading the breaker monitor:

```
==>BRE W <Enter>

Breaker Monitor Preload

Internal Trip Counter (0-65000)          A-phase =        0   ? 14 <Enter>
                                         B-phase =        0   ? 7 <Enter>
                                         C-phase =        0   ? 10 <Enter>
Internal Current (0.0-999999 kA)         IA      =        0.0 ? 32.4 <Enter>
                                         IB      =        0.0 ? 18.6 <Enter>
                                         IC      =        0.0 ? 22.6 <Enter>

External Trip Counter (0-65000)          A-phase =        0   ? 2 <Enter>
                                         B-phase =        0   ? 1 <Enter>
                                         C-phase =        0   ? 2 <Enter>
External Current (0.0-999999 kA)         IA      =        0.0 ? 0.8 <Enter>
                                         IB      =        0.0 ? 0.6 <Enter>
                                         IC      =        0.0 ? 0.7 <Enter>

Percent Wear (0-100%)                    A-phase =        0   ? 22 <Enter>
                                         B-phase =        0   ? 28 <Enter>
                                         C-phase =        0   ? 25 <Enter>

Involved Phase Counter (0-65000)         A-phase =        0   ? 10 <Enter>
                                         B-phase =        0   ? 5 <Enter>
                                         C-phase =        0   ? 8 <Enter>
                                         Ground  =        0   ? 3 <Enter>

Last Reset                               Date    = 07/30/2003 ? 02/12/2003
                                         Time    = 16:07:17 ? 09:25:14
Save Changes(Y/N)? Y <Enter>

FEEDER 1                               Date: 08/29/2003  Time: 08:00:00.000
STATION A                              Time Source: internal

                           A           B           C           G
Internal Trip Counter      14          7           10
Internal Current (kA)      32.4        18.6        22.6
```

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```
                                                          (Continued from previous page)
External Trip Counter         2      1      2
External Current (kA)         0.8    0.6    0.7

Percent Wear                  22     28     25

Involved Phase Counter        10     5      8      3


LAST RESET 02/12/2003 09:25:14
==>
```

The **BRE W** command only saves new settings after the Save Changes
(Y/N)? message. If a data entry error is made using the **BRE W** command, the
values echoed after the Invalid format, changes not saved message are
the previous **BRE** values, unchanged by the aborted **BRE W** attempt.

Use the **BRE R** command to reset the breaker monitor:

```
==>BRE R <Enter>

Reset Trip Counters and Accumulated Currents/Wear
Are you sure (Y,N)? Y <Enter>


FEEDER 1                              Date: 07/30/2003  Time: 16:07:18.039
STATION A                             Time Source: internal

                              A      B      C      G
Internal Trip Counter         0      0      0
Internal Current (kA)         0.0    0.0    0.0

External Trip Counter         0      0      0
External Current (kA)         0.0    0.0    0.0


Percent Wear                  0      0      0

Involved Phase Counter        0      0      0      0

LAST RESET 07/30/2003 16:07:17
==>
```

BTT Command

Use the **BTT** commands to display battery test results or force a battery test.
See *Section 8: Metering and Monitoring* for details on how the battery system
monitor operates.

BTT (View Battery Test Results)

Use the **BTT** command to display the daily battery test results.

Command	Description	Access Level
BTT	Display latest battery load test results and time remaining until next discharge test.	B

➤ If the most recent battery test passed, the following message is
displayed:

```
Battery test state is:  OK
Time until next battery test:  XX hours
```

where XX is the estimated time until the next automatic battery
test, in hours.

➤ If the DTFAIL Relay Word bit is already asserted (most recent
test failed), the following message is displayed:

```
Battery Failure
```

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➤ If a battery test is in progress, the following message is displayed:

```
Battery test in progress
```

BTT NOW (Initiate Battery Test)

Use the **BTT NOW** command to request an immediate battery test.

Command	Description	Access Level
BTT NOW	Force a battery test and view the results.	B

1. If a battery test is already in progress, the following message is displayed:

   ```
   Battery test in progress
   ```

2. If the battery charger is in Discharge mode or Startup mode, no test is performed and the following message is displayed:

   ```
   Command Failed: Battery charger in Discharge or
   Startup mode.
   ```

3. If neither (1) nor (2) apply, a test is performed. The following message is displayed and a new period appears after the message for each second of the battery test.

   ```
   Battery test initiated...
   ```

4. At the end of the test, the display will be one of the following:

   ```
   Battery test state is:  OK
   ```
   or
   ```
   Battery test state is:  FAILED
   ```

CASCII Command

The **CAS** command produces the Compressed ASCII configuration message. This configuration instructs an external computer on the method for extracting data from other Compressed ASCII commands.

Command	Description	Access Level
CAS	Display Compressed ASCII configuration message.	0

CEV Command (Compressed Event Reports)

Use the **CEV** command to retrieve event reports in compressed format. See *Section 12: Analyzing Events* for details on retrieving event reports, including additional parameters.

Command	Description	Access Level
CEV *n*	Display event report *n* in Compressed ASCII format. Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.	1

CEV HIF (Compressed HIF Event Reports; Only Available in Relays That Support Arc Sense Technology)

Use the **CEV HIF** command to retrieve high-impedance (HIF) event reports in compressed format. See *HIF Event Reporting on page 12.52* for details on retrieving HIF event reports.

Command	Description	Access Level
CEV HIF *n*	Display HIF event report *n* in Compressed ASCII format. Parameter *n* corresponds to the event number from the **HIS HIF** command.	1

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CHISTORY Command

The **CHI** command is the **HISTORY** command for the Compressed ASCII command set.

Command	Description	Access Level
CHI	Display history data in Compressed ASCII format.	1

CHISTORY HIF Command (Only Available in Relays That Support Arc Sense Technology)

The **CHI HIF** command is the **HISTORY HIF** command for the Compressed ASCII command set. See *HIF Event History on page 12.51*.

Command	Description	Access Level
CHI HIF	Display HIF history data in Compressed ASCII format.	1

CLO Command (Close Breaker)

Use the close command (**CLO**, **CLO A**, **CLO B**, or **CLO C**) to assert the specified Relay Word bit (CC3, CCA, CCB, or CCC) for 1/4 cycle.

Command	Description	Access Level
CLO	Momentarily assert the three-phase close Relay Word bit CC3.	B
CLO *n*	This command asserts a single-phase close Relay Word bit (**CLO A** asserts CCA, **CLO B** asserts CCB, **CLO C** asserts CCC).	B

Program the close command Relay Word bit into the close control equation (CL3P, CLA, CLB, or CLC) to enable assertion of the close Relay Word bit (CLOSE3P, CLOSEA, CLOSEB, or CLOSEC) with the close command. Program the close Relay Word bit to enable assertion of an output contact (e.g., OUT201 := CLOSE3P) to close a recloser/circuit breaker. See *Section 6: Close and Reclose Logic* for a detailed explanation of the close logic.

To issue the **CLO** command, enter the following:

```
==>CLO <Enter>
Close Breaker  (Y/N) ? Y <Enter>
Are you sure (Y/N) ? Y <Enter>
==>
```

Typing **N <Enter>** after either of the Y/N prompts aborts the command.

The main board breaker jumper supervises the **CLO** command (see *Figure 2.48*). If the breaker jumper is not in place (breaker jumper = OFF), the recloser control does not perform the **CLO** command and responds with the following message:

```
Aborted: No Breaker Jumper
```

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COM Command (Communication Data)

The **COM** command displays integral relay-to-relay (MIRRORED BITS) communications data. For more information on MIRRORED BITS communications, see *Appendix D: MIRRORED BITS Communications*. To get a summary report, enter the command with the channel parameter (**A** or **B**).

Command	Description	Access Level
COM *c* **COM** *c row1 row2* **COM** *c date1 date2*	Show communications summary report (COM report) on MIRRORED BITS Channel *c* (*c* = A or B).	1
COM *c* **L …**	For all **COM** commands (except **COM** *c* **C**), **L** causes the specified report records to be listed after the summary.	1
COM *c* **C**	Clear/reset communications buffer data for MIRRORED BITS Channel *c* (or both channels if *c* is not specified).	1

Parameter	Description
c	Parameter *c* is A for Channel A and B for Channel B. If only one MIRRORED BITS port is enabled the channel specifier may be omitted.
row1 row2	Append *row1* to return a chronological progression of the first *row1* rows. Append *row1* and *row2* to return all rows between *row1* and *row2*, beginning with *row1* and ending with *row2*. Enter the smaller number first to display a numeric progression of rows through the report. Enter the larger number first to display a reverse numeric progression of rows.
date1 date2	Append *date1* to return all rows with this date. Append *date1* and *date2* to return all rows between *date1* and *date2* beginning with *date1* and ending with *date2*. Enter the oldest date first to display a chronological progression through the report. Enter the newest date first to display a reverse chronological progression. Date entries are dependent on the date format setting DATE_F.

```
=>COM A <Enter>

FEEDER 1                                Date: 08/29/2003  Time: 08:00:00.000
STATION A                               Time Source: internal

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxx     CID=xxxx
Summary for Mirrored Bits channel A

For 08/05/2003 09:33:57.453 to 08/05/2003 11:43:23.327

    Total failures   1                  Last error  Data error
    Relay Disabled   1
    Data error       0                  Longest Failure    1.113 sec.
    Re-Sync          0
    Underrun         0                  Unavailability  0.000143
    Overrun          0
    Parity error     0
    Framing error    0                  Loop-back     0
    Bad Re-Sync      0

    =>
```

If only one MIRRORED BITS port is enabled, the channel specifier may be omitted. Use the **L** parameter to get a summary report, followed by a listing of the COM records.

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```
=>COM L <Enter>

FEEDER 1                              Date: 08/29/2003  Time: 08:00:00.000
STATION A                             Time Source: internal

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx     CID=xxxx
Summary for Mirrored Bits channel A

For 08/29/2003 08:00:00.000 to 08/30/2003 08:00:00.000

      Total failures     1            Last error  Relay Disabled
      Relay Disabled     1
      Data error         0            Longest Failure   203.388 sec.
      Re-Sync            0
      Underrun           0            Unavailability  0.999979
      Overrun            0
      Parity error       0
      Framing error      0            Loop-back    0
      Bad Re-Sync        0


Failure                 Recovery
#   Date       Time          Date       Time          Duration  Cause
1   08/29/2003 08:00:00.0000 08/29/2003 08:00:45.0000  45.000   Relay Disabled

=>
```

There may be as many as 255 records in the extended report.

CON Command (Control Remote Bit)

The **CON** command is a two-step command that allows you to control Relay Word bits RB01–RB32 (see Rows 94–97 in *Table F.1*).

Command	Description	Access Level
CON *n*[a]	First step of a two-command sequence. The SEL-651R-2 will prompt for the second step (sub-command), shown below.	B

[a] Parameter n is a number from 1 to 32 representing RB01–RB32.

Step 1.   At the Access Level B prompt, type:

      a. **CON**

      b. a space

      c. the number of the remote bit you wish to control (1–32)

Step 2.   Press the **<Enter>** key on your computer.

The relay responds by repeating your command followed by a colon.

Step 3.   At the colon, type the Control subcommand you wish to perform (see *Table 10.19*).

The following example shows the steps necessary to pulse Remote Bit 5 (RB5):

```
==>CON 5 <Enter>
CONTROL RB5: PRB 5 <Enter>
==>
```

You must enter the same remote bit number in both steps in the command. If the bit numbers do not match, the relay responds:

```
Invalid Command
```

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Table 10.19   SEL-651R-2 Control Subcommand

Subcommand	Description
SRB *n*	Set Remote Bit *n* ("ON" position)
CRB *n*	Clear Remote Bit *n* ("OFF" position)
PRB *n*	Pulse Remote Bit *n* for 1/4 cycle ("MOMENTARY" position)

See *Remote Bits on page 7.22* for more information.

COP Command (Copy Settings Group or DNP Map)

NOTE: If EZ settings are not enabled in the source Group m, but are enabled in the destination Group n, the COP command is not allowed.

Copy relay and SELOGIC control equation settings from source Settings Group *m* to destination Settings Group *n* with the **COP *m n*** command. Copy DNP map settings from Map *m* to Map *n* with the **COP D *m n*** command. Settings group numbers range from 1 to 8 and DNP maps range from 1 to 3. After entering settings into one settings group or map with the **SET** command, copy them to the other group(s) or map(s) with the **COP** command. Use the **SET** command to modify the copied settings. The relay disables for a few seconds and the ALARM output pulses if you copy settings into the active group. This is similar to a Group Change (see *Multiple Settings Groups on page 7.23*).

Command	Description	Access Level
COP *m n*	Copy settings from Group *m* to Group *n*.	2
COP D *m n*	Copy DNP Map *m* to Map *n*.	2

Parameter	Description
m	Parameter *m* is a group number from 1 to 8 or a map number from 1 to 3.
n	Parameter *n* is a group number from 1 to 8 or a map number from 1 to 3.

For example, to copy settings from Group 1 to Group 3 issue the following command:

```
=>>COP 1 3 <Enter>
Copy 1 to 3
Are you sure (Y/N) ? Y <Enter>

Please wait...
Settings copied
=>>
```

COUNTER Command (View SELOGIC Counters)

The **COU** command displays the present value of the SELOGIC counters.

Command	Description	Access Level
COU *k*	Show the SELOGIC counter values. Enter *k* for repeat count.	1

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NOTE: The counter data displayed by the **COU** command may not be from the same processing interval for each counter.

The **COU** command is convenient to use while testing the SEL<small>OGIC</small> Counter settings (see *Counters on page 7.13*). Below is a sample of the **COU** command response.

```
=>COU <Enter>
FEEDER 1                                      Date: 08/05/2003  Time: 12:07:32.532
STATION A                                     Time Source: internal

     SC01      SC02      SC03      SC04      SC05      SC06      SC07      SC08
        0        14         0         0         0         0         0         0


     SC09      SC10      SC11      SC12      SC13      SC14      SC15      SC16
        0         0         0         0         0         0         0         0


=>
```

CST Command (Compressed Status)

The **CST** command generates a recloser control status report in Compressed ASCII format.

Command	Description	Access Level
CST	Display the recloser control status in Compressed ASCII format.	1

CSU Command

The **CSU** command retrieves the event summary information event report *n* in Compressed ASCII format (see *Section 12: Analyzing Events*).

Command	Description	Access Level
CSU *n*	Display the event summary for event report *n* (with label lines) in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.	1

CSU HIF Command (Only Available in Relays That Support Arc Sense Technology)

The **CSU HIF** command retrieves the HIF event summary information for event report *n* in Compressed ASCII format (see *HIF Event Summary on page 12.48*).

Command	Description	Access Level
CSU HIF *n*	Display the HIF event summary for event report *n* in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* corresponds to the event number from the **HIS HIF** command.	1

DAT Command (View/Change Date)

DAT displays the date stored by the internal calendar/clock. If the Global setting DATE_F is set to MDY, the date is displayed as month/day/year. If the date format setting DATE_F is set to YMD, the date is displayed as year/month/day.

Command	Description	Access Level
DAT	Display the internal clock date.	1
DAT *date*	Set the internal clock date to *date* (DATE_F set to MDY, YMD, or DMY).	1

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NOTE: After setting the date, allow at least 60 seconds before powering down the relay or the new setting may be lost.

To set the date:

➤ Type **DAT mm/dd/yyyy <Enter>** if the DATE_F setting is MDY.

➤ If the DATE_F is set to YMD, enter **DAT yyyy/mm/dd <Enter>**.

➤ If the DATE_F is set to DMY, enter **DAT dd/mm/yyyy <Enter>**.

To set the date to May 20, 2016, enter the following:

```
=>DAT 5/20/2016 <Enter>
05/20/2016
=>
```

You can separate the month, day, and year parameters with spaces, commas, slashes, colons, and semicolons. Set the year in 4-digit format (for dates 2000–2099).

If an IRIG-B or SNTP time synchronization signal is connected to the relay, the **DAT** command cannot alter the month or day portion of the date. If the IRIG-B or SNTP time source is IEEE C37.118 compliant and Global setting IRIGC = C37.118, or if an SNTP time source is connected, the **DAT** command cannot alter the year. See *Configuring High-Accuracy Timekeeping on page J.21* for more details on IRIG time sources.

DNAMES Command

The **DNA** command produces the ASCII names of all Relay Word bits reported in a Fast Meter message in Compressed ASCII format (see *DNA Message on page I.13*).

Command	Description	Access Level
DNA X or **T**	Display ASCII names of all Relay Word bits digital I/O. Either X or T is mandatory and results are identical.	0

ETH Command (View Ethernet Port Information)

Use the **ETH** command when troubleshooting Ethernet connections. The report shown is for a relay with dual copper Ethernet ports with Port 5 setting NETMODE = FAILOVER. Different Ethernet configurations and different NETMODE settings result in slightly different information being displayed. See *Establishing Communications Using an Ethernet Port and Telnet or the Web Server* for a description of the settings and operating modes related to the Ethernet port.

Command	Description	Access Level
ETH	Displays information about Ethernet port(s)	1
ETH C	Clears Ethernet port sent and received packets, bytes, and error statistics	1

```
=>ETH <Enter>
SEL-651R-2                    Date: 8/27/13   Time: 05:40:00.603
STATION A

NETMODE: FAILOVER

PRIMARY PORT:  5A
ACTIVE PORT:   5A

            LINK   SPEED  DUPLEX MEDIA
PORT 5A     Up     100M   Full   TX
PORT 5B     Down   --     --     TX

IP Port:

MAC: 00-30-A7-01-09-2E
IP ADDRESS: 192.168.1.2
SUBNET MASK: 255.255.255.0
DEFAULT GATEWAY: 192.168.1.1
```
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```
      PACKETS          BYTES          ERRORS
   SENT  RCVD     SENT    RCVD     SENT  RCVD
     2     2      128     172       0     0

 GOOSE Port:

 MAC: 00-30-A7-01-09-2F

      PACKETS          BYTES          ERRORS
   SENT  RCVD     SENT    RCVD     SENT  RCVD
    34     2     6932     184       0     0
 =>
```

EVE Command (Event Reports)

Use the **EVE** command to view event reports. See *Section 12: Analyzing Events* for further details on retrieving event reports, including additional parameters.

Command (Parameter n Is Optional)	Description	Access Level
EVE *n*	Return event report *n* (including settings and summary) at full length with 4-samples/cycle data. Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.	1

EXI Command

Use the **EXI** command to exit a Telnet session on any of the Ethernet ports.

Command	Description	Access Level
EXI	Exit active Telnet session	0

FIL Command

The **FIL** command provides an efficient means of transferring files between the relay and a PC. Software applications, such as QuickSet, use the **FIL** command to send and receive settings files to and from the relay.

The **FIL** command uses Ymodem transfer protocol to transfer setting files and to retrieve event files (see *Retrieving COMTRADE Event Files on page 12.15*). Reports, event, and diagnostic files are available to read via Ymodem as a batch. See the *Ymodem File Structure on page 10.29* for more information on using wildcards.

Command	Description	Access Level
FIL DIR	Display a list of available files.	1
FIL READ *filename*	Transfer settings or event file *filename* from the relay to the PC.	1
FIL WRITE *filename*	Transfer settings file *filename* from the PC to the relay.	2
FIL SHOW *filename*	Displays contents of the ASCII file *filename*.	1

The following response shows the available reports, events, and settings available with the **FIL** command. For more information on these files, see *Virtual File Interface on page 10.24*.

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```
=>>FIL DIR <Enter>
CFG.TXT              R
ERR.TXT              R
SET_ALL.TXT         RW

SET_1.TXT           RW
SET_2.TXT           RW
SET_3.TXT           RW
SET_4.TXT           RW
SET_5.TXT           RW          Group Settings
SET_6.TXT           RW
SET_7.TXT           RW
SET_8.TXT           RW

SET_D1.TXT          RW
SET_D2.TXT          RW          DNP Settings
SET_D3.TXT          RW

SET_G.TXT           RW          Global Settings

SET_L1.TXT          RW
SET_L2.TXT          RW
SET_L3.TXT          RW
SET_L4.TXT          RW
SET_L5.TXT          RW          Logic Settings
SET_L6.TXT          RW
SET_L7.TXT          RW
SET_L8.TXT          RW

SET_M.TXT           RW          Modbus Settings

SET_P1.TXT          RW
SET_P2.TXT          RW
SET_P3.TXT          RW          Port Settings
SET_P5.TXT          RW
SET_PF.TXT          RW

SET_R.TXT           RW          SER Settings

SET_F.TXT           RW          Front-Panel Settings

SWCFG.ZIP           RW

C4_nnnnn.CEV        R           Compressed ASCII Filtered Event Reports

CHF_nnnnn.CEV       R           Compressed HIF Event Reports

CR_nnnnn.CEV        R           Compressed ASCII Raw Event Reports

HF_nnnnn.CFG        R
HF_nnnnn.DAT        R           COMTRADE High-Impedance Event Report
HF_nnnnn.HDR        R

HR_nnnnn.CFG        R
HR_nnnnn.DAT        R           COMTRADE Raw Event Report
HR_nnnnn.HDR        R

STATUS.TXT          R
VEC_D.TXT           R           Diagnostic Reports
VEC_E.TXT           R

BRE.TXT             R           Breaker Monitor Report

CHISTORY.TXT        R
CHISTORY_HIF.TXT    R
HISTORY.TXT         R           History Reports
HISTORY_HIF.TXT     R

LDP.TXT             R           Load Profile Report

MET.TXT             R
MET_D.TXT           R
MET_E.TXT           R
MET_H.TXT           R           Metering Reports
MET_HIF.TXT         R
MET_M.TXT           R
MET_PM.TXT          R

SER.TXT             R           SER Report

SSI.TXT             R           Sag, Swell, and Interruption Report

TAR.TXT             R           Relay Word Bits Status Report
```

Figure 10.8   FILE DIR Command Example Response

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GOOSE Command

Use the GOOSE (**GOO**) command to display transmit and receive GOOSE messaging and statistics information, which can be used for troubleshooting. The GOOSE command variants and options are shown below.

Command Variant	Description	Access Level
GOO	Display GOOSE information.	1
GOO *k*	Display GOOSE information *k* times.	1
GOO S	Display a list of GOOSE subscriptions with their ID.	1
GOO S *n*	Display GOOSE statistics for subscription ID *n*.	1
GOO S ALL	Display GOOSE statistics for all subscriptions.	1
GOO S *n* **L**	Display GOOSE statistics for subscription ID *n* including error history.	1
GOO S ALL L	Display GOOSE statistics for all subscriptions including error history.	1
GOO S *n* **C**	Clear GOOSE statistics for subscription ID *n*.	1
GOO S ALL C	Clear GOOSE statistics for all subscriptions.	1

The information displayed for each GOOSE IED is described in the following table.

Information Field	Description
`Transmit GOOSE Control Reference`	This field represents the GOOSE control reference information that includes the IED name, ldInst (Logical Device Instance), LN0 lnClass (Logical Node Class), and GSEControl name (GSE Control Block Name) (e.g., SEL_651R_1CFG/LLN0GOGooseDSet13).
`Receive GOOSE Control Reference`	This field represents the goCbRef (GOOSE Control Block Reference) information that includes the iedName (IED name), ldInst (Logical Device Instance), LN0 lnClass (Logical Node Class), and cbName (GSE Control Block Name) (e.g., SEL_651R_1CFG/LLN0GOGooseDSet13).
`MultiCastAddr` (Multicast Address)	This hexadecimal field represents the GOOSE multicast address.
`Ptag`	This three-bit decimal field represents the priority tag value, where spaces are used if the priority tag is unknown.
`Vlan`	This 12-bit decimal field represents the virtual LAN (Local Area Network) value, where spaces are used if the virtual LAN is unknown.
`StNum` (State Number)	This hexadecimal field represents the state number that increments with each state change.
`SqNum` (Sequence Number)	This hexadecimal field represents the sequence number that increments with each retransmitted GOOSE message sent.
`TTL` (Time to Live)	This field contains the time (in ms) before the next message is expected.
`Code`	When appropriate, this text field contains warning or error condition text that is abbreviated as follows:

Code Abbreviation	Explanation
OUT OF SEQUENC	Out of sequence error
CONF REV MISMA	Configuration Revision mismatch
NEED COMMISSIO	Needs Commissioning
TEST MODE	Test Mode
MSG CORRUPTED	Message Corrupted
TTL EXPIRED	Time to live expired

Information Field	Description
`Transmit Data Set Reference`	This field represents the DataSetReference (Data Set Reference) that includes the IED name, LN0 lnClass (Logical Node Class), and GSEControl datSet (Data Set Name) (e.g., SEL_651R_1CFG/LLN0$DSet13).

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Information Field	Description
Receive Data Set Reference	This field represents the datSetRef (Data Set Reference) that includes the iedName (IED name), ldInst (Logical Device Instance), LN0 lnClass (Logical Node Class), and datSet (Data Set Name) (e.g., SEL_651R_1CFG/LLN0$DSet13).
Ctrl Ref/ ControlBlockReference	This is the GOOSE control block reference. It is a concatenation of the logical device name, LLN0 (logical node containing the control block), GO (functional constraint), and the GSEControl name. (e.g., SEL_651R_1CFG/LLN0GOGooseDSet13)
AppID	This is the application identifier as a decimal number.
From	This is the date and time the current statistics collection started.
To	This is the date and time the GOOSE statistics command was executed.
Accumulated downtime duration	This represents the total amount of time a subscription was in an error state. The duration is displayed in the format: hhhh:mm:ss.zzz.
Maximum downtime duration	This represents the maximum amount of time a subscription was continuously in error state. The duration is displayed in the format: hhhh:mm:ss.zzz.
Date & time maximum downtime began	This is the date and time the recorded maximum downtime started.
Number of messages received out-of-sequence (OOS)	This represents the total number of messages received with either the state number and/or sequence number out-of-sequence. This includes cases where more than one instance of a message is received within a single relay processing interval. In this case, the most recent message is processed and the others are discarded.
Number of time-to-live (TTL) violations detected	This represents the total number of times a message was not received within the expected period/interval.
Number of messages incorrectly encoded or corrupted	This represents the total number of messages that were identified with this subscription but were either incorrectly encoded or encoded with a wrong dataset.
Number of messages lost due to receive overflow	This represents the total number of messages that were not processed because memory resources were exhausted. This includes cases where more than one instance of a message is received within a single relay processing interval. In this case, the most recent message is processed and the others are discarded.
Calculated max. sequential messages lost due to OOS	This represents the maximum estimated number of messages that were missed after receiving a message with a higher state or sequence number than expected.
Calculated number of messages lost due to OOS	This represents the total of all estimated number of messages lost as a result of state or sequence number skip in received messages.

An example response to the GOOSE commands is shown in *Figure 10.9*.

```
=>GOO <Enter>

GOOSE Transmit Status

 MultiCastAddr   Ptag:Vlan AppID  StNum     SqNum     TTL     Code
 -------------------------------------------------------------------------
 SEL_651R2_1CFG/LLN0$GO$GooseDSet13
  01-0C-CD-01-00-12 4:1     4114   1         11175     638
  Data Set: SEL_651R2_1CFG/LLN0$DSet13

GOOSE Receive Status

 MultiCastAddr   Ptag:Vlan AppID  StNum     SqNum     TTL     Code
 -------------------------------------------------------------------------
 SEL_487E_1CFG/LLN0$GO$GOOSEMessage1
  01-0C-CD-01-00-10 4:1     4112   2         18248     2000
  Data Set: SEL_487E_1CFG/LLN0$DSet13

 SEL_487E_1CFG/LLN0$GO$GOOSEMessage2
  01-0C-CD-01-00-05 4:3     5      3         18249     2000
  Data Set: SEL_487E_1CFG/LLN0$DSet03

 SEL_487E_1CFG/LLN0$GO$GOOSEMessage3
  01-0C-CD-01-00-06 4:3     6      2         18250     2000
  Data Set: SEL_487E_1CFG/LLN0$DSet04
```

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```
SEL_487E_1CFG/LLN0$GO$GOOSEMessage4
 01-0C-CD-01-00-07 4:3    7     2           18250     2000
 Data Set: SEL_487E_1CFG/LLN0$DSet10


=>GOO S 1 L <Enter>

 SubsID 1
--------------------------------------------------------------------------
 Ctrl Ref: SEL_487E_1CFG/LLN0$GO$GOOSEMessage1
 AppID   : 4112
 From    : 03/14/2012 12:21:04.694 To: 03/14/2012 15:28:08.734

 Accumulated downtime duration                  : 0000:00:00.029
 Maximum downtime duration                      : 0000:00:00.029
 Date & time maximum downtime began             : 03/14/2012 12:21:04.719
 Number of messages received out-of-sequence(OOS)  : 0
 Number of time-to-live(TTL) violations detected   : 1
 Number of messages incorrectly encoded or corrupted: 0
 Number of messages lost due to receive overflow   : 0
 Calculated max. sequential messages lost due to OOS: 0
 Calculated number of messages lost due to OOS     : 0

 #   Date        Time          Duration       Failure
 1   03/14/2012  12:21:04.719  0000:00:00.029  TTL EXPIRED

 =>
```

Figure 10.9   GOOSE Command Response

GRO Command (Display Active Settings Group Number)

Use the **GRO** command to display the active settings group number. The **GRO** *n* command changes the active settings group to Settings Group *n*.

Command	Description	Access Level
GRO	Display active group number.	1
GRO *n*	Change the active group to Group *n* (*n* = 1–8).	B

See *Multiple Settings Groups on page 7.23* for further details on settings groups.

To change to Settings Group 2, enter the following:

```
==>GRO 2 <Enter>
Change to Group 2
Are you sure (Y/N) ? Y <Enter>
Active Group = 2
==>
```

The relay switches to Group 2 and pulses the **ALARM** contact. If the serial port AUTO setting = Y, the relay sends the group switch report:

```
==>
FEEDER 1                        Date: 02/02/09   Time: 09:40:34.611
STATION A

Active Group = 2
==>
```

If any of the SELOGIC control equations settings SS1–SS8 are asserted to logical 1, the active settings group may not be changed with the **GRO** command—SELOGIC control equations settings SS1–SS6 have priority over the **GRO** command in active settings group control.

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For example, assume Settings Group 1 is the active settings group and the SS1 setting is asserted to logical 1 (e.g., SS1 = IN101 and optoisolated input IN101 is asserted). An attempt to change to Settings Group 2 with the **GRO 2** command will not be accepted:

```
==>GRO 2 <Enter>
No group change (see manual)
Active Group = 1
==>
```

For more information on settings group selection, see *Multiple Settings Groups on page 7.23*.

HIS Command (Event Summaries/History)

HIS displays event summaries or allows you to clear event summaries (and corresponding event reports) from nonvolatile memory. See *Event History (HIS) on page 12.10*.

Command	Description	Access Level
HIS	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list.	1
HIS *n*	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list beginning at event *n*.	1
HIS E	Same as HIS, but events are identified with a unique number in the range 10000–65535.	1
HIS C	Clear/reset the event history and all corresponding event reports from nonvolatile memory.	1

HIS HIF Command (HIF Event Summaries/History; Only Available in Relays That Support Arc Sense Technology)

HIS HIF displays high-impedance fault (HIF) summaries or allows you to clear HIF event summaries (and corresponding event reports) from nonvolatile memory. See *HIF Event History on page 12.51*.

Command	Description	Access Level
HIS HIF	Display HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.	1
HIS HIF *n*	Display *n* HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.	1
HIS HIF C	Clear/reset the HIF event history and all corresponding event reports from nonvolatile memory.	1

HIZ Command

HIZ displays the ground overcurrent, high-impedance (50G HIZ) event reports or allows you to clear the HIZ event reports from nonvolatile memory. See *50G High-Impedance (HIZ) Fault Detection on page 4.116*.

Command	Description	Access Level
HIZ	Display HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.	1
HIZ *n*	Display *n* HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.	1
HIZ C	Clear/reset the HIZ event reports from nonvolatile memory.	1

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ID Command

Use the **ID** command to extract device identification codes (see *Appendix I: Configuration, Fast Meter, and Fast Operate Commands*).

Command	Description	Access Level
ID	Display the firmware id, user id, device code, part number, and configuration information.	0

INI HIF Command (Only Available In Relays That Support Arc Sense Technology)

Use the **INI HIF** command to force the high-impedance fault detection algorithm into initial tuning mode. See *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111* for details.

Command	Description	Access Level
INI HIF	Force HIF algorithm into initial tuning mode.	2

L_D Command (Load Firmware)

Use the **L_D** command to load firmware. See *Appendix A: Firmware and Manual Versions* for information on changes to the firmware and instruction manual. See *Appendix B: Firmware Upgrade Instructions* for further details on downloading firmware.

Command	Description	Access Level
L_D	Prepare the relay to receive new firmware.	2

LDP Command (Load Profile Report)

Use the **LDP** command to view the Load Profile report. For more information on Load Profile reports, see *Section 8: Metering and Monitoring*.

Command	Description	Access Level
LDP	Display a numeric progression of all load profile report rows.	1
LDP *row1 row2* **LDP** *date1 date2*	Display a chronological or reverse chronological subset of the load profile rows.	1
LDP D	Display the number of days of Load Profile memory capacity remaining before data overwrite occurs.	1
LDP C	Clear the Load Profile data from memory.	1

LOG HIF Command (Only Available In Relays That Support Arc Sense Technology)

The **LOG HIF** command displays the instantaneous high-impedance alarm and fault detection values as a percentage of their final pickup value and the state of Relay Word bits, HIA2_A, HIA2_B, HIA2_C, HIF2_A, HIF2_B, and HIF2_C. The HI2 column indicates the state of the alarm and fault bits for the A, B, and C phases. The A-phase bits are represented by the left row, the B-phase bits are represented by the middle row, and the C-phase bits are represented by the right row. The command can display as many as 500 entries. If a high-impedance fault detecting bit (HIF2_A, HIF2_B, HIF2_C, HIA2_A, HIA2_B, or HIA2_C) is asserted, a new entry is logged in the **LOG HIF** command every one second. An entry is also logged if the percentage of detection changes by more than 10 percent.

Command	Description	Access Level
LOG HIF	Display the HIF alarm and fault calculations as a percentage of their value.	1
LOG HIF *n*	Display the *n* most recent LOG HIF entries.	1
LOG HIF C	Clear the LOG HIF data from memory.	1

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```
=>>LOG HIF <Enter>
                                     PERCENTAGE
Date       Time                 ALG.2A ALG.2B ALG.2C HI2
10/01/2012 15:20:18.053 ALARM   45.00   0.00  85.00  000
                        FAULT   66.67   0.00  33.33  000

                                     PERCENTAGE
Date       Time                 ALG.2A ALG.2B ALG.2C HI2
10/01/2012 15:20:19.053 ALARM   45.00   0.00  90.00  000
                        FAULT   33.33   0.00  66.67  000

                                     PERCENTAGE
Date       Time                 ALG.2A ALG.2B ALG.2C HI2
10/01/2012 15:20:20.053 ALARM   45.00   0.00  95.00  000
                        FAULT   33.33   0.00 100.00  001

                                     PERCENTAGE
Date       Time                 ALG.2A ALG.2B ALG.2C HI2
10/01/2012 15:20:21.054 ALARM   45.00   0.00 100.00  001
                        FAULT    0.00   0.00 100.00  001

Example display when the number parameter is entered.


=>>LOG HIF 2 <Enter>
                                     PERCENTAGE
Date       Time                 ALG.2A ALG.2B ALG.2C HI2
10/01/2012 15:20:20.053 ALARM   45.00   0.00  95.00  000
                        FAULT   33.33   0.00 100.00  001

                                     PERCENTAGE
Date       Time                 ALG.2A ALG.2B ALG.2C HI2
10/01/2012 15:20:21.054 ALARM   45.00   0.00 100.00  001
                        FAULT    0.00   0.00 100.00  001
```

LOO Command (Loop Back)

The **LOO** (LOOP) command is used for testing the MIRRORED BITS communications channel. For more information on MIRRORED BITS, see *Appendix D: MIRRORED BITS Communications*.

Command	Description	Access Level
LOO *c t*	Set MIRRORED BITS Channel *c* (*c* = A or B) to loopback for duration *t* minutes (*t* = 1–5000; default is 5). The received MIRRORED BITS elements are forced to default values during the loopback test.	2
LOO *c t* **DATA**	Set MIRRORED BITS Channel *c* to loopback for duration *t* minutes. **DATA** allows the received MIRRORED BITS elements to change during the loopback test.	2
LOO *c* **R**	Cease loopback on MIRRORED BITS communications Channel *c*. Reset the channel to normal use.	2

Parameter	Description
c	Append this parameter (*c* = A or B) to specify which channel to use if more than one MIRRORED BITS communications channel is enabled.
t	Append this parameter to specify the time-out period in *t* minutes (*t* = 1–5000; if not specified, default is 5).

With the transmitter of the communications channel physically looped back to the receiver, the MIRRORED BITS addressing will be wrong and ROK will deassert. The **LOO** command tells the MIRRORED BITS software to temporarily expect to see its own data looped back as its input. In this mode, LBOK will assert if error-free data are received. The **LOO** command with just the channel specifier enables looped back mode on that channel for five minutes, while the inputs are forced to the default values.

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MAC Command

The **MAC** command returns the Media Access Control (MAC) address of the Ethernet port. If IEC 61850 GOOSE messaging is enabled, an additional GOOSE MAC address is also displayed.

Command	Description	Access Level
MAC	Display Ethernet port MAC address	1

```
=>MAC <Enter>

Port 5 MAC Address: 00-30-A7-00-00-00
```

MET Command (Metering Data)

The **MET** commands provide access to recloser control metering data. Metered quantities include phase voltages and currents, sequence component voltages and currents, power, frequency, energy, demand, and maximum/minimum logging of selected quantities. To make the extensive amount of meter information manageable, the recloser control divides the displayed information into seven groups:

➤ Fundamental

➤ Demand

➤ Energy

➤ THD/Harmonics

➤ Maximum/Minimum

➤ RMS

➤ High-Impedance Fault (HIF)

Metering data retrieval and display are described in the following subsections. See *Section 8: Metering and Monitoring* for details on metering.

MET (Fundamental Metering)

Use the **MET** command to display fundamental metering data.

Command	Description	Access Level
MET *k*	Display instantaneous metering data *k* times.	1

The **MET** *k* command displays instantaneous magnitudes, and angles if applicable, of the following quantities:

NOTE: See Ground Switch Option on page 8.3 for details on the IG quantity used in the SEL-651R-2 metering functions.

Currents	IA,B,C,N	Input currents (A primary)
	IG	Ground current (A primary; $I_G = 3I_0 = I_A + I_B + I_C$ when Relay Word bit GNDSW = 0; I_G = IN when GNDSW = 1)
Voltages	VAY, VBY, VCY, VAZ, VBZ, VCZ	Phase-to-neutral voltages (kV primary)
	VABY, VBCY, VCAY, VABZ, VBCZ, VCAZ	Calculated phase-to-phase voltages (kV primary)

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	Vbase	Demand average value based on V_1, (subject to the operating logic of the *Voltage Sag, Swell, and Interruption Elements on page 4.59*) when setting ESSI :=Y in the active settings group. Vbase registers a value only after valid three-phase voltage signals have been present since the last Vbase initialization.
Power	MVAA,B,C	Single-phase MVA
	MVA3P	Three-phase MVA
	MWA,B,C	Single-phase megawatts
	MW3P	Three-phase megawatts
	MVARA,B,C	Single-phase megavars
	MVAR3P	Three-phase megavars
Power Factor	PFA,B,C	Single-phase power factor; leading or lagging
	PF3P	Three-phase power factor; leading or lagging
Sequence	I1, 3I2, 3I0	Positive-, negative-, and zero-sequence currents (A primary)
	V1Y, V2Y, V1Z, V2Z	Positive- and negative-sequence voltages (kV primary)
	3V0Y, 3V0Z	Zero-sequence voltage (kV primary)
Frequency	FREQ (Hz)	Instantaneous power system frequency (measured on Y voltage terminal or Z voltage terminal—see *Table 8.1*).

NOTE: Three-phase MVA (MVA3P) is the arithmetic sum of the single-phase measurements MVAA, MVAB, and MVAC. Three-phase power factor (PF3P) is calculated with MW3P and MVAR3P (not MVA3P).

The recloser control references metering angles to voltage VAY or VAZ (according to Global setting VSELECT), if the reference voltage is greater than 13 V secondary; if VSELECT := OFF, angles are referenced to A-phase current. Angles range from –179.99 to 180.00 degrees.

To view instantaneous metering values, use the **MET *k*** command, where *k* is an optional parameter to specify the number of times (1–32767) to repeat the meter display. The recloser control displays the meter report once if *k* is not specified. Below is a sample of metering data from the SEL-651R-2.

```
=>MET <Enter>

FEEDER 1                              Date: 08/29/2003  Time: 08:00:00.000
STATION A                             Time Source: internal
                A        B        C        N        G
I MAG (A)     279.528  309.668  270.246   34.967   34.967
I ANG (deg)    -14.60  -134.55   105.36  -119.03  -119.03

                I1       3I2      3I0
I MAG (A)     286.480   35.784   35.615
I ANG (deg)    -14.60    93.00  -120.97

                VAY      VBY      VCY      VAZ      VBZ      VCZ
V MAG (kV)     14.356   14.356   14.358   14.358   14.356   14.357
V ANG (deg)     0.00   -120.00   120.01    0.01  -119.99   120.01

                VABY     VBCY     VCAY     VABZ     VBCZ     VCAZ
V MAG (kV)     24.866   24.866   24.868   24.868   24.866   24.868
V ANG (deg)    30.00   -89.99    150.00   30.01   -89.99    150.01

                V1Y      V2Y      3V0Y     V1Z      V2Z      3V0Z
V MAG (kV)     14.357    0.001    0.003   14.357    0.001    0.002
V ANG (deg)     0.00   -47.78    173.66    0.01   -16.33    45.40

                                                  (Continued on next page)
```

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```
                                                        (Continued from previous page)

                      A          B          C          3P
        MW           3.883      4.303      3.754      11.940
        MVAR         1.012      1.117      0.981       3.110
        MVA          4.013      4.446      3.880      12.339
        PF           0.97       0.97       0.97        0.97
                     LAG        LAG        LAG         LAG

        FREQ  (Hz)      59.99
        Vbase (kV)       0.000

        =>
```

MET D (Demand Metering)

Use the following commands to view or reset demand and peak demand metering values.

Command	Description	Access Level
MET D	Display demand and peak demand metering data.	1
MET RD	Reset demand metering data.	1
MET RP	Reset peak demand metering data.	1

The **MET D** command displays the demand and peak demand values of the following quantities:

Currents	IA,B,C,N	Input currents (A primary)
	IG	Ground current (A primary; $I_G = 3I_0 = I_A + I_B + I_C$ when Relay Word bit GNDSW = 0; I_G = IN when GNDSW = 1)
	3I2	Negative-sequence current (A primary)
Power	MVAA,B,C	Single-phase MVA
	MVA3P	Three-phase MVA
	MWA,B,C	Single-phase megawatts
	MW3P	Three-phase megawatts
	MVARA,B,C	Single-phase megavars
	MVAR3P	Three-phase megavars
Reset Time	Demand, Peak	Last reset times for the demands and peak demands

Below is a sample of demand metering data from the SEL-651R-2.

```
    =>MET D <Enter>

    FEEDER 1                             Date: 08/29/2003  Time: 08:00:00.000
    STATION A                            Time Source: internal
                IA       IB       IC       IN       IG       3I2
    DEMAND     190.1    206.2    184.9     17.3     17.3     20.8
    PEAK       190.1    206.2    184.9     17.3     17.3     20.8


                MVAA     MVAB     MVAC     MVA3P
    DEMAND       2.7      3.0      2.7      8.3
    PEAK         2.7      3.0      2.7      8.3

    MWA    MWB    MWC    MW3P    MVARA   MVARB   MVARC   MVAR3P
    DEMAND IN    0.0    0.0    0.0     0.0     0.0     0.0     0.0     0.0
    PEAK IN      0.0    0.0    0.0     0.0     0.0     0.0     0.0     0.0
    DEMAND OUT   2.6    2.9    2.6     8.1     0.7     0.7     0.7     2.1
    PEAK OUT     2.6    2.9    2.6     8.1     0.7     0.7     0.7     2.1
    LAST DEMAND RESET 08/29/2003 08:00:00.000
    LAST PEAK   RESET 08/29/2003 08:05:00.000

    =>
```

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For more information on recloser control demand metering quantity calculations, see *Demand Metering on page 8.6*.

MET E (Energy Metering)

Use the following commands to view or reset energy metering values.

Command	Description	Access Level
MET E	Display energy metering data.	1
MET RE	Reset energy metering data.	1

Energy	MWhA,B,C	Single-phase megawatt hours (in and out)
	MWh3P	Three-phase megawatt hours (in and out)
	MVARhA,B,C	Single-phase megavar hours (in and out)
	MVARh3P	Three-phase megavar hours (in and out)
Reset Time		Last energy meter reset time

Below is a sample of energy metering data from the SEL-651R-2:

```
=>MET E <Enter>

FEEDER 1                        Date: 02/04/2014  Time: 15:44:41.304
STATION A                       Time Source: internal
        MWhA     MWhB     MWhC    MWh3P    MVARhA   MVARhB   MVARhC   MVARh3P
IN      0.019    0.019    0.019    0.057    0.044    0.041    0.041    0.126
OUT    90.739   90.701   90.450  271.889    1.822    1.657    1.311    4.789
LAST RESET 01/12/2014 03:07:37.462

=>
```

For more information on recloser control energy metering quantity calculations, see *Energy Metering on page 8.15*.

Recloser control accumulated energy metering values function like those in an electromechanical energy meter. The SEL-651R-2 starts over at 0 after energy meter reaches 99999.999 MWh or 99999.999 MVARh.

MET H (THD and Harmonic Metering)

Use the **MET H** command to display the following for each measured quantity:

Command	Description	Access Level
MET H	Display fundamental magnitudes, root-mean-square (rms) magnitudes, Total Harmonic Distortion, and harmonic magnitudes for the first 16 harmonics.	1

Below is a sample of harmonic metering data from the SEL-651R-2:

```
=>MET H <Enter>

FEEDER 1                        Date: 2012/12/30  Time: 08:27:52.572
STATION A                       Time Source: internal
            IA        IB        IC        IN
Fund(A)  2002.000  1998.000  1999.000     0.081
RMS (A)  2001.122  2000.589  1998.546     0.194
THD (%)       0         5         0         0

            VAY       VBY       VCY       VAZ       VBZ       VCZ
Fund(kV)  12.002    11.996    12.002    12.001    11.998    12.004
RMS (kV)  12.002    12.000    11.999    11.999    11.999    11.999
THD (%)       0         3         0         0         2         0
```
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```
                                                         (Continued from previous page)
Harmonic    IA     IB     IC     IN     VAY    VBY    VCY    VAZ    VBZ    VCZ
2  (%)      0      0      0      0      0      0      0      0      0      0
3  (%)      0      0      0      0      0      0      0      0      0      0
4  (%)      0      0      0      0      0      0      0      0      0      0
5  (%)      0      0      0      0      0      0      0      0      0      0
6  (%)      0      0      0      0      0      0      0      0      0      0
7  (%)      0      0      0      0      0      0      0      0      0      0
8  (%)      0      0      0      0      0      0      0      0      0      0
9  (%)      0      0      0      0      0      0      0      0      0      0
10 (%)      0      0      0      0      0      0      0      0      0      0
11 (%)      0      0      0      0      0      0      0      0      0      0
12 (%)      0      0      0      0      0      0      0      0      0      0
13 (%)      0      0      0      0      0      0      0      0      0      0
14 (%)      0      0      0      0      0      0      0      0      0      0
15 (%)      0      0      0      0      0      0      0      0      0      0
16 (%)      0      0      0      0      0      0      0      0      0      0

=>
```

MET M (Maximum/Minimum Metering)

Use the following commands to view or reset maximum and minimum metering values.

Command	Description	Access Level
MET M	Display maximum and minimum metering data.	1
MET RM	Reset maximum and minimum metering data. All values will display RESET until new maximum/minimum values are recorded.	1

Maximum and minimum values include:

Currents	IA,B,C,N	Input currents (A primary)
	IG	Ground current (A primary; $IG = 3I0 = IA + IB + IC$ when Relay Word bit $GNDSW = 0$; $IG = IN$ when $GNDSW = 1$)
Voltages	VAY, VBY, VCY, VAZ, VBZ, VCZ	Voltages (kV primary)
Power	MW3P	Three-phase megawatts
	MVAR3P	Three-phase megavars
	MVA3P	Three-phase megavolt-amperes
Reset Time		Last maximum/minimum reset time

Below is a sample of maximum/minimum metering data from the SEL-651R-2:

```
=>MET M <Enter>

FEEDER 1                                  Date: 08/29/2003  Time: 08:00:00.000
STATION A                                 Time Source: internal
          Max     Date        Time          Min     Date        Time
IA(A)     280.1   07/08/2003  11:57:32.648  235.3   07/08/2003  11:57:24.647
IB(A)     310.0   07/08/2003  11:58:37.199  269.6   07/08/2003  11:56:49.976
IC(A)     270.4   07/08/2003  11:58:18.522  269.8   07/08/2003  11:57:34.782
IN(A)     35.0    07/08/2003  11:58:40.925  35.0    07/08/2003  11:58:12.121
IG(A)     35.0    07/08/2003  11:58:40.925  0.0     07/08/2003  11:57:34.249
VAY(kV)   14.4    07/08/2003  11:57:36.391  14.4    07/08/2003  11:56:50.509
VBY(kV)   14.4    07/08/2003  11:57:07.578  14.4    07/08/2003  11:57:35.849
VCY(kV)   14.4    07/08/2003  11:57:58.786  14.4    07/08/2003  11:58:40.391
VAZ(kV)   14.4    07/08/2003  11:58:42.529  14.4    07/08/2003  11:56:46.242
VBZ(kV)   14.4    07/08/2003  11:59:07.062  14.4    07/08/2003  11:58:44.659
VCZ(kV)   14.4    07/08/2003  11:58:53.727  14.4    07/08/2003  11:57:12.916
MW3P      11.9    07/08/2003  11:58:30.790  10.8    07/08/2003  11:57:24.647
MVAR3P    3.1     07/08/2003  11:59:03.861  2.8     07/08/2003  11:57:24.647
MVA3P     12.3    07/08/2003  11:58:30.790  11.1    07/08/2003  11:57:24.647
LAST RESET 08/29/2003 08:00:00.000

=>
```

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For more information on recloser control maximum/minimum metering quantity calculations, see *Maximum/Minimum Metering on page 8.17*.

MET RMS (RMS Metering)

Use the **MET RMS** command to display rms (root-mean-square) quantities.

Command	Description	Access Level
MET RMS	Display root-mean-square (rms) metering data.	1

Below is a sample of rms metering data from the SEL-651R-2:

```
=>MET RMS <Enter>

FEEDER 1                            Date: 08/29/2003  Time: 08:00:00.000
STATION A                           Time Source: internal
           IA        IB        IC        IN
RMS (A)  279.676   309.791   270.219   34.990

           VAY       VBY       VCY       VAZ       VBZ       VCZ
RMS (kV) 14.357    14.357    14.358    14.359    14.357    14.357

            A         B         C        3P
Avg. MW   3.885     4.305     3.755    11.944

=>
```

MET PM (Synchrophasor Metering)

The **MET PM** command (available when TSOK = logical 1 and EPMU = Y) displays the synchrophasor measurements. For more information, see *View Synchrophasors by Using the MET PM Command on page J.17*.

Command	Description	Access Level
MET PM	Display synchrophasor measurements.	1
MET PM *k*	Display synchrophasor measurements *k* times.	1
MET PM *time*	Display synchrophasor measurements at specific time.	1
MET PM HIS	Display the most recent **MET PM** synchrophasor report.	1

Use the **MET PM** command to help with commissioning. The command:

```
=>MET PM time <Enter>
```

triggers a synchrophasor meter command at precisely the time specified. Parameter `time` must be in 24-hour format, e.g., 15:11:00.000. Compare magnitudes and phases of quantities displayed in response to the **MET PM** command to reports from other relays triggered at the same instant to verify correct phasing and polarity of current and voltage connections. To help facilitate comparing meter reports between several relays, the command:

```
=>MET PM HIS <Enter>
```

recalls the most recently triggered synchrophasor meter report. Values displayed reflect present relay settings, not settings in effect at the time of the original **MET PM** command.

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For exploratory testing, the command:

```
=>MET PM k <Enter>
```

repeats the **MET PM** command *k* times. The trigger times of the *k* reports are not carefully controlled, but the trigger times are still accurately displayed in the reports.

The output from an SEL-651R-2 is shown:

```
=>MET PM <Enter>

FEEDER 1                                Date: 08/05/2011  Time: 14:38:27.000
STATION A                               Time Source: external

                                                              PMDOK = 1
Time Quality   Maximum time synchronization error:    0.000 (ms)  TSOK = 1

Synchrophasors
                 Y-Terminal Voltages        Pos.-Seq. Voltage
               VAY      VBY      VCY            V1Y
MAG (kV)      12.040   12.083   12.045        12.056
ANG (DEG)     48.925  -70.898  169.221        49.083


                 Z-Terminal Voltages        Pos.-Seq. Voltage
               VAZ      VBZ      VCZ            V1Z
MAG (kV)      12.033   12.060   12.024        12.039
ANG (DEG)     49.424  -70.429  169.750        49.581

               Phase Currents       Neutral Current  Pos.-Seq. Current
               IA       IB       IC          IN              I1
MAG (A)      987.906  989.363  988.834      0.868         988.689
ANG (DEG)     47.624  -72.086  168.303     46.693          47.947

FREQ (Hz) 60.004
Rate-of-change of FREQ (Hz/s)   -0.00

Digitals

SV01   SV02   SV03   SV04   SV05   SV06   SV07   SV08
 0      0      0      0      0      0      0      0
SV09   SV10   SV11   SV12   SV13   SV14   SV15   SV16
 0      0      0      0      0      0      0      0
SV17   SV18   SV19   SV20   SV21   SV22   SV23   SV24
 0      0      0      0      0      0      0      0
SV25   SV26   SV27   SV28   SV29   SV30   SV31   SV32
 0      0      0      0      0      0      0      0
SV33   SV34   SV35   SV36   SV37   SV38   SV39   SV40
 0      0      0      0      0      0      0      0
SV41   SV42   SV43   SV44   SV45   SV46   SV47   SV48
 0      0      0      0      0      0      0      0
SV49   SV50   SV51   SV52   SV53   SV54   SV55   SV56
 0      0      0      0      0      0      0      0
SV57   SV58   SV59   SV60   SV61   SV62   SV63   SV64
 0      0      0      0      0      0      0      0
=>
```

MET HIF (High-Impedance Fault [HIF] Metering; Only Available in Relays That Support Arc Sense Technology)

The **MET HIF** command displays the instantaneous high-impedance alarm and fault detection values as a percentage of their final pickup value.

Command	Description	Access Level
MET HIF *k*	Display the HIF detection values as a percentage of their final pickup value. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).	1

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```
=>>MET HIF <Enter>

FEEDER 1                              Date: 07/31/2012  Time: 16:21:25.256
STATION A                            Time Source: internal

              ALG.2 A     ALG.2 B     ALG.2 C
Alarm (%)       18.59       34.78       12.56
Fault (%)       14.89       15.46        7.55

The MET HIF command with the optional repeat parameter equal to 3.


=>>MET HIF 3 <Enter>

FEEDER 1                              Date: 07/31/2012  Time: 16:21:56.424
STATION A                            Time Source: internal

              ALG.2 A     ALG.2 B     ALG.2 C
Alarm (%)       20.15       12.08        4.26
Fault (%)        9.12       10.79        1.63

FEEDER 1                              Date: 07/31/2012  Time: 16:21:56.428
STATION A                            Time Source: internal

              ALG.2 A     ALG.2 B     ALG.2 C
Alarm (%)       22.46       11.44        8.56
Fault (%)        8.99        5.45        3.09

FEEDER 1                              Date: 07/31/2012  Time: 16:21:56.599
STATION A                            Time Source: internal

              ALG.2 A     ALG.2 B     ALG.2 C
Alarm (%)       25.80       11.15        9.16
Fault (%)       10.05        5.40        4.02
```

OPE Command (Open Breaker)

Use the open command (**OPE**, **OPE A**, **OPE B**, or **OPE C**) to assert the specified Relay Word bit (OC3, OCA, OCB, or OCC) for 1/4 cycle.

Command	Description	Access Level
OPE	Momentarily assert the three-phase open Relay Word bit OC3.	B
OPE *n*	Assert a single-phase close Relay Word bit (**OPE A** asserts OCA, **OPE B** asserts OCB, **OPE C** asserts OCC).	B

Program the open command Relay Word bit into the trip control equation (TR3P, TRA, TRB, or TRC) to enable assertion of the trip Relay Word bit (TRIP3P, TRIPA, TRIPB, or TRIPC) with the open command. Program the trip Relay Word bit to enable assertion of an output contact (e.g., OUT201 := TRIP3P) to trip a recloser/circuit breaker. See *Section 5: Trip and Target Logic* for a detailed explanation of the trip logic.

To issue the **OPE** command, enter the following:

```
==>OPE <Enter>

Open Breaker (Y/N) ? Y <Enter>
Are you sure (Y/N) ? Y <Enter>
==>
```

Typing **N <Enter>** after either of the Y/N prompts aborts the command.

The main board breaker jumper supervises the **OPEN** command (see *Figure 2.48*). If the breaker jumper is not in place (breaker jumper is OFF), the recloser control does not perform the **OPEN** command and responds with the following:

```
Aborted: No Breaker Jumper
```

NOTE: Though the intention of serial port commands **OPE A**, **OPE B**, and **OPE C** is to provide tripping for separate recloser Poles A, B, and C, respectively, there is no direct connection. Rather, these commands receive their function by virtue of how their corresponding Relay Word bits OCA, OCB, and OCC are programmed, as inferred above.

Also, no settings have control over the **OPE** serial port commands or their resultant Relay Word bits. Thus, settings such as Global setting BKTYP (breaker type), though involved in structuring single-phase or three-phase logic, have no effect on the **OPE** serial port commands or their resultant Relay Word bits.

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PAS Command
(Change Passwords)

The relay is shipped with factory-default passwords for Access Levels 1, B, 2, and C. These passwords are shown in *Table 10.20*.

Command	Description	Access Level
PAS *level*	Change the password for Access Level *level*.	2

Table 10.20   Factory-Default Passwords for Access Levels 1, B, 2, and C

Access Level	Factory-Default Password
1	OTTER
B	EDITH
2	TAIL
C	CLARKE

The **PAS** command allows you to change existing Level 1, B, and 2 passwords at Access Level 2 and allows you to change the Level C password from Level C. To change passwords, enter **PAS *x***, where *x* is the access level whose password is being changed. The relay will prompt for the old password, the new password, and a confirmation of the new password.

To change the password for Access Level 1, enter the following:

```
=>>PAS 1 <Enter>

Old Password: *********

New Password: ******
Confirm New Password: ******

Password Changed
=>>
```

The new password will not echo on the screen and passwords cannot be viewed from the device. When the password is changed for any access level the Relay Word bit CHGPASS will pulse for approximately one second. Record the new password in a safe place for future reference.

If the passwords are lost or you wish to operate the relay without password protection, put the main board Access jumper in place (Access jumper = ON). Refer to *Figure 2.48* for Access jumper information. With the Access jumper in place, issue the **PAS *x*** command at Access Level 2. The relay will prompt for a new password and a confirmation of the new password.

Passwords may include as many as 12 characters. See *Table 10.21* for valid characters. Upper- and lowercase letters are treated as different characters. Strong passwords consist of 12 characters, with at least one special character or digit and mixed-case sensitivity, but do not form a name, date, acronym, or word. Passwords formed in this manner are less susceptible to password guessing and automated attacks. Examples of valid, distinct strong passwords include:

➤ Ot3579A24.68

➤ Ih2d&s4u-Iwg

➤ .651r.Nt9g-t

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Table 10.21 Valid Password Characters

Alpha	ABCDEFGHIJKLMNOPQRSTUVWXYZ abcdefghijklmnopqrstuvwxyz
Numeric	0123456789
Special	! " # $ % & ' ( ) * , - . / : ; < = > ? @ [\ ] ^ _ ` {	} ~

The relay shall issue a weak password warning if the new password does not include at least one special character, number, lowercase letter, and uppercase letter.

```
=>>PAS 1 <Enter>

Old Password: *********

New Password: ******
Confirm New Password: ******

Password Changed
=>>

CAUTION:  This password can be strengthened.  Strong passwords do not include a name,
    date, acronym, or word.  They consist of the maximum allowable characters, with
    at least one special character, number, lower-case letter, and upper-case
    letter.  A change in password is recommended.

=>>
```

PUL Command (Pulse Output Contact)

The **PUL** command allows you to pulse any of the output contacts for a specified length of time. The selected contact will close or open depending on the output contact type (a or b) (see *Output Contacts on page 7.34*).

Command	Description	Access Level
PUL *n s*	Pulse output *n* for *s* seconds. (*n* = output name; OUT201, OUT202 [all models]; OUT101–OUT108 [models with extra I/O]; *s* = 1–30 seconds)	B

To pulse **OUT101** for five seconds:

```
==>PUL OUT101 5 <Enter>
Are you sure (Y/N) ? Y <Enter>
==>
```

If the response to the `Are you sure (Y/N) ?` prompt is **N** or **n**, the command is aborted.

The **PUL** command is supervised by the main board Breaker Control jumper (see *Figure 2.48*). If the Breaker Control jumper is not in place (OFF), the relay does not execute the **PUL** command and responds:

```
Aborted:  No Breaker Jumper
```

The relay generates an event report if any of the output contacts are pulsed. The **PUL** command is primarily used for testing purposes.

QUI Command (Quit Access Level)

The **QUI** command returns the relay to Access Level 0.

Command	Description	Access Level
QUI	Go to Access Level 0.	0

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To return to Access Level 0, enter the command:

```
=>QUI <Enter>
```

The relay sets the port access level to 0 and responds:

```
FEEDER 1                          Date: 02/02/09 Time: 08:55:33.986
STATION A

=
```

The = prompt indicates the relay is back in Access Level 0.

R_S Command (Restore Factory Defaults)

Use the **R_S** command to restore factory-default settings.

Command	Description	Access Level
R_S	Restore the factory-default settings and passwords and reboot the system.[a]	2

[a] Only available after a settings or critical RAM failure.

SER Command (Sequential Events Recorder Report)

Use the **SER** command to view the Sequential Events Recorder report. For more information on SER reports (see *Section 12: Analyzing Events*).

Command	Description	Access Level
SER	Display a chronological progression of all available SER rows (as many as 1024 rows). Row 1 is the most recently triggered row and row 1024 is the oldest.	1
SER *n* **SER** *row1 row2* **SER** *date1* **SER** *date1 date2*	Display a chronological or reverse chronological subset of the SER rows.	
SER C	Clear/reset the SER records.	1

SET Command (Change Settings)

The **SET** command allows the user to view or change the relay settings (see *Table 9.2*).

Command	Description	Access Level
SET *n*	Change Group *n* settings, beginning at the first setting in each instance (*n* = 1–8; if not specified, default is the active settings group).	2
SET D *n*	Change DNP Map *n* settings (*n* = 1, 2, or 3).	2
SET F	Change Front-Panel settings.	2
SET G	Change Global settings.	2
SET L *n*	Change Logic settings for Settings Group *n* (*n* = 1–8; if not specified, default is the active settings group).	2
SET M	Change Modbus settings.	2
SET P *p*	Change Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).	2
SET R	Change Report settings.	2

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Command	Description	Access Level
SET … *name*	For all **SET** commands, jump ahead to specific setting by entering setting *name*.	2
SET … TERSE	For all **SET** commands, the **TERSE** command disables the automatic **SHO** command after settings entry.	2

SHO Command (Show/View Settings)

Use the **SHO** command to view relay settings, SELOGIC control equations, Global settings, Serial Port settings, Sequential Events Recorder (SER) settings, and Text Label settings.

Command	Description	Access Level
SHO *n*	Show Group *n* settings (*n* = 1–8; if not specified, default is the active settings group).	1
SHO D *n*	Show DNP Map *n* settings (*n* = 1, 2, or 3).	1
SHO F	Show Front-Panel settings.	1
SHO G	Show Global settings.	1
SHO L *n*	Show Logic settings for Settings Group *n* (*n* = 1–8; if not specified, default is the active settings group).	1
SHO M	Show Modbus settings.	1
SHO P *p*	Show Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).	1
SHO R	Show Report settings.	1
SHO … *name*	For all **SHO** commands, jump ahead to specific setting by entering setting *name*.	

You may append a setting name to each of the commands to specify the first setting to display (e.g., **SHO 1 E50P** displays the setting Group 1 relay settings starting with setting E50P). The default is the first setting.

The **SHO** commands display only the enabled settings. To display all settings, including disabled/hidden settings, append an **A** to the **SHO** command (e.g., **SHO 1 A**).

See *Figure 9.30–Figure 9.39* for example **SHO** command responses for the SEL-651R-2 with factory-default settings.

SNS Command

Use the **SNS** command to view the name string of the SER (SER1, SER2, SER3, and SER4) settings (see *Appendix I: Configuration, Fast Meter, and Fast Operate Commands*).

Command	Description	Access Level
SNS	Display the name string of the SER settings.	0

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SSI Command (Voltage Sag/Swell/Interruption Report)

View and manage voltage SSI data with the **SSI** commands. See *Sag/Swell/Interruption (SSI) Report on page 12.42* for further details on the SSI report, and *Voltage Sag, Swell, and Interruption Elements on page 4.59* for details on the VSSI elements and Vbase value.

Command	Description	Access Level
SSI *n* **SSI** *row1 row2* **SSI** *date1* **SSI** *date1 date2*	Display a chronological progression of all SSI report rows. Use the **SSI** command with parameters to display a chronological or reverse chronological subset of the SSI report rows.	1
SSI T	Manually trigger the VSSI recorder.	1
SSI C	Clear the SSI report from nonvolatile memory.	1
SSI R	Reset the VSSI recorder logic and clear the Vbase value.	1

Parameter	Description
n	Append *n* to return latest n rows in SSI report (n = 1 to several thousand, where 1 is the most recent entry).
row1 row2	Append *row1* and *row2* to return all rows between *row1* and *row2*, beginning with *row1* and ending with *row2*. Enter the smaller number first to display a numeric progression of rows through the report. Enter the larger number first to display a reverse numeric progression of rows.
date1 *date1 date2*	Append *date1* to return all rows with this date. Append *date1* and *date2* to return all rows between *date1* and *date 2* beginning with *date1* and ending with *date2*. Enter the oldest date first to display a chronological progression through the report. Enter the newest date first to display a reverse chronological progression. Date entries are dependent on the date format setting DATE_F.

Viewing the SSI Report

The recorded voltage SSI data can be viewed from any settings group, even if setting ESSI := N. Row 1 is the most recently triggered row. View the SSI report by date or by SSI row number.

See *Figure 12.12* for an example SSI report.

If the requested SSI event report rows do not exist, the recloser control responds with the following:

```
No Voltage Sag/Swell/Interruption Data
```

Clearing the SSI Report

Clear the SSI report from nonvolatile memory with the **SSI C** command, as shown in the following example:

```
=>SSI C <Enter>
Clear the Voltage/Sag/Swell Interruption buffer
Are you sure (Y/N)? Y <Enter>
Clearing Complete
```

The **SSI C** command is available in any settings group and on any serial port.

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If the **SSI C** command is issued on one serial port while another serial port is being used to display an SSI report, the clearing action will terminate the SSI report retrieval.

Triggering the SSI Recorder

Manually trigger the voltage SSI Recorder by using the **SSI T** command. The **SSI T** command is available only if Group setting ESSI := Y in the active settings group.

If an **SSI T** command is issued when setting ESSI := N, the recloser control responds as follows:

```
Command is not available
```

If an **SSI T** command is issued before Vbase has initialized, the recloser control responds as follows:

```
Did Not Trigger
```

See *Vbase Initialization on page 4.62* for details on the initializing conditions.

Resetting the SSI Recorder Logic

After the recloser control detects satisfactory voltage signals for at least 12 seconds, the SSI Recorder is armed and a Ready entry is written to the SSI archive.

The **SSI R** command is available only if Group setting ESSI := Y in the active settings group. Attempting the **SSI R** command when ESSI := N will display the following:

```
Command is not available
```

See *Positive-Sequence Reference Voltage, Vbase on page 4.61* for more details.

STA Command (Relay Self-Test Status)

The **STA** command displays the status report, showing the relay self-test information.

Command	Description	Access Level
STA k	Display the recloser control self-test information k times (k = 1–32767; if not specified, default is 1).	1
STA S	Display the memory and execution utilization for the SELOGIC control equations.	1
STA C	Reboot the recloser control and clear self-test warning and failure status results.	2

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A sample output of an SEL-651R-2 is shown:

```
=>STA <Enter>

Serial Number: xxxxxxxxxxxxxxx

FEEDER 1                             Date: 05/10/2012  Time: 15:58:51.646
STATION A                            Time Source: external

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx   CID=4629

SELF TESTS

Channel Offsets (mV)   W=Warn    F=Fail
     I1      I2      I3      IN     V1Y     V2Y     V3Y     V1Z     V2Z     V3Z     MOF
OS   -2      -2      -2      -2      -2      -2      -2      -2      -2      -2      -2
OSH  -0      -0      -0      -0

Power Supply Voltages (V)   W=Warn    F=Fail
   +5V_PS   +5V_REG   +15V_PS   -15V_PS   +12V_TC   +5VA_PS   -5VA_PS
    4.97      4.99     15.07    -15.21     11.90      5.04     -5.03

Temperature               RTC     HMI
  30.3  degrees Celsius    OK      OK

Integrated Circuit and Board Status
    RAM     ROM     A/D    FLASH     FPGA   EEPROM  INT_BRD  USB_BRD  COM_BRD
    OK      OK      OK      OK       OK      OK      OK       NA       OK

Mains, Battery Monitor and Capacitor Monitor
   INPBV   12VAUX    CMODE     VBAT     IBAT    TCCAPV
   12.21   12.25   FLT_CHG    12.20     0.03     53.1

Relay Enabled

=>
```

STA Command Row and Column Definitions

Serial Number	Recloser Control Serial Number.
FID	Firmware identifier string containing the module firmware revision number.
CID	Firmware checksum identifier.
Channel Offsets	Display measured dc offset voltages in millivolts for the current and voltage channels. The MOF (master) status is the dc offset in the A/D circuit when a grounded input is selected.
Power Supply Voltages	Display power supply voltages in Vdc for the power supply outputs.
Temperature	Displays the internal module temperature in degrees Celsius.
Integrated Circuit and Board Status	RAM, ROM, CR_RAM, FLASH, FPGA—These tests verify the SEL-651R-2 memory components. The columns display OK if memory is functioning properly; the columns display FAIL if the memory area has failed. A/D—Analog to Digital convert status. INT_BRD—Interface board status. USB_BRD—USB board port status, if supplied. COM_BRD—Dual copper, and dual or single fiber-optic Ethernet ports status, if supplied.

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Mains, Battery Monitor, and Capacitor Monitor	INPBV	DC POWER IN voltage (see *Figure 2.9*)
	12VAUX	AUXILIARY POWER SUPPLY (see *Figure 2.9*)
	CMODE	Battery charger mode:

		STARTUP	Startup
		CUR_CHG	Constant current charge
		FST_CHG	Fast charge
		FLT_CHG	Float charge
		DISCHRG	Discharge
		BAT_FLR	Battery failure
		BAT_TST	Battery discharge test

	VBAT	BATTERY voltage (see *Figure 2.9*)
	IBAT	BATTERY current in mA dc (see *Figure 2.9*). If the battery is discharging, a minus sign precedes the current value.
	TCCAPV	CAPACITORS voltage (see *Figure 2.9*)

Note: W (Warning) or F (Failure) is appended to the values to indicate an out-of-tolerance condition.

The relay latches all self-test warnings and failures to capture transient out-of-tolerance conditions. To reset the self-test statuses, use the **STA C** command from Access Level 2:

```
=>>STA C <Enter>
```

The relay responds:

```
Reboot the relay and clear status
Are you sure (Y/N) ?
```

If you select "N" or "n", the relay displays the following and aborts the command:

```
Canceled
```

If you select "Y", the relay displays:

```
Rebooting the relay
```

The relay then restarts (just like powering down, then powering up relay) and all diagnostics are re-run before the relay is enabled.

Refer to *Table 13.2* for self-test thresholds and corrective actions.

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SUM HIF Command (Only Available in Relays That Support Arc Sense Technology)

The **SUM HIF** command displays a long summary of an HIF event report. The long summary contains more information than is available from the **HIS HIF** command, but it is shorter than the full HIF event report. A sample report is shown below. *HIF Event Summary on page 12.48* describes the various fields of information available in the HIF summary event report.

Command	Description	Access Level
SUM HIF *n*	Displays the HIF summary event report *n*, where *n* is the unique event number from the HIS HIF report in the range 10000 to 65535. SUM HIF with no *n* displays the most recent HIF summary event report.	1

```
=>>SUM HIF <Enter>

651R-2                          Date: 07/31/2012  Time: 16:41:18.481
Station A                       Time Source: internal

Event Number = 10002
Event: HIF Fault                        HIF Phase: B,C
Downed Conductor: NO                    Freq: 60.00
Breaker A: OPEN
Breaker B: OPEN
Breaker C: OPEN

Pre-trigger (A):
IARMS          IBRMS          ICRMS
1.5            1.5            1.6

Post-trigger (A):
1.8            1.5            1.5

Pre-trigger (A):
SDIA           SDIB           SDIC
368.4          336.7          376.1

Post-trigger (A):
10587.0        339.0          374.0

SUM HIF command using the unique event identification number.

=>>SUM HIF 10002 <Enter>

651R-2                          Date: 07/31/2012  Time: 16:41:18.481
Station A                       Time Source: internal

Event Number = 10002
Event: HIF Fault                        HIF Phase: B,C
Downed Conductor: NO                    Freq: 60.00
Breaker A: OPEN
Breaker B: OPEN
Breaker C: OPEN

Pre-trigger (A):
IARMS          IBRMS          ICRMS
1.5            1.5            1.6

Post-trigger (A):
1.8            1.5            1.5

Pre-trigger (A):
SDIA           SDIB           SDIC
368.4          336.7          376.1

Post-trigger (A):
10587.0        339.0          374.0

=>>
```

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TAR Command (Display Relay Element Status)

The **TAR** command displays the status of front-panel target LEDs or relay elements, whether they are asserted or deasserted.

Command	Description	Access Level
TAR	Display Relay Word row 0 or last displayed target row.	1
TAR name k	Display the Relay Word row containing *name*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).	1
TAR n k	Display Relay Word row number *n*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).	1
TAR LIST	Display all target rows. If ROW is specified, the relay includes the target row number on each line.	1
TAR R	Clears front-panel tripping targets. Shows Relay Word Row 0.	1
TAR ROW …	Shows the Relay Word row number at the start of each line, with other selected **TAR** commands as described above, such as **n**, **name**, **k**, and **LIST**.	1

The target row elements are listed in rows of eight. The first four rows (0, 1, 2, and 3) correspond to the relay front-panel target LEDs shown in *Table 10.22*. The target row elements are asserted when the corresponding front-panel target LED is illuminated.

The remaining target rows (4–135) correspond to the Relay Word as described in *Table F.1* and *Table F.2*. A Relay Word bit is either at a logical 1 (asserted) or a logical 0 (deasserted). Relay Word bits are used in SELOGIC control equations (see *Relay Word Bits on page 7.2*).

The **TAR** command does not remap the front-panel target LEDs, as is done in some previous SEL relays.

The **TAR** command options are:

TAR n k
or
TAR ROW n k

Shows Relay Word row number *n* (0–135). *k* is an optional parameter to specify the number of times (1–32767) to repeat the Relay Word row display. If *k* is not specified, the Relay Word row is displayed once. Adding **ROW** to the command displays the Relay Word Row number at the start of each line.

TAR name k
or
TAR ROW name k

Shows Relay Word row containing Relay Word bit name (e.g., TAR 50C1 displays Relay Word Row 4). Valid names are shown in *Table 10.22*, *Table F.1*, and *Table F.2*. The value *k* is an optional parameter to specify the number of times (1–32767) to repeat the Relay Word row display. If *k* is not specified, the Relay Word row is displayed once. Adding **ROW** to the command displays the Relay Word Row number at the start of each line.

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TAR LIST or **TAR ROW LIST**	Shows all the Relay Word bits in all of the rows. Adding **ROW** to the command displays the Relay Word Row number at the start of each line.	

NOTE: The **TAR R** command cannot reset the latched Targets if a TRIP condition is present.

TAR R — Clears front-panel tripping target LEDs **TRIP, A FAULT, B FAULT, C FAULT, GROUND, SEF, FAST CURVE, DELAY CURVE, HIGH CURRENT, OVER/UNDER FREQUENCY,** and **OVER/UNDER VOLTAGE.** Unlatches the trip logic for testing purposes (see *Figure 5.1*). Shows Relay Word Row 0.

Table 10.22 Front-Panel Targets and the TAR Command

TAR 0 (Front-Panel LEDs)	EN	TRIPLED	*	*	*	*	*	*
TAR 1 (Front-Panel LEDs)	TLED_08	TLED_07	TLED_06	TLED_05	TLED_04	TLED_03	TLED_02	TLED_01
TAR 2 (Front-Panel LEDs)	TLED_16	TLED_15	TLED_14	TLED_13	TLED_12	TLED_11	TLED_10	TLED_09
TAR 3 (Front-Panel LEDs)	TLED_24	TLED_23	TLED_22	TLED_21	TLED_20	TLED_19	TLED_18	TLED_17

Command **TAR SH13P 10** is executed in the following example:

```
=>TAR SH13P 10 <Enter>

79RS3P    79CY3P    79LO3P    SH03P     SH13P     SH23P     SH33P     SH43P
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0

79RS3P    79CY3P    79LO3P    SH03P     SH13P     SH23P     SH33P     SH43P
0         0         1         0         0         0         1         0
0         0         1         0         0         0         1         0

=>
```

Note that the Relay Word row containing the SH13P bit is repeated 10 times. In this example, the reclosing relay is in the Lockout State (79LO3P = logical 1) and the shot is at shot = 3 (SH33P = logical 1). Command **TAR 64** will report the same data because the SH33P bit is in Row 64 of the Relay Word.

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Command **TAR ROW LIST** is executed in the following example.

```
=>TAR ROW LIST <Enter>
Row     EN         TRIPLED    *        *        *        *        *        *
0       1          0          0        0        0        0        0        0

Row     TLED_08    TLED_07    TLED_06  TLED_05  TLED_04  TLED_03  TLED_02  TLED_01
1       0          0          0        0        0        0        1        1

Row     TLED_16    TLED_15    TLED_14  TLED_13  TLED_12  TLED_11  TLED_10  TLED_09
2       0          1          0        0        0        0        0        0

Row     TLED_24    TLED_23    TLED_22  TLED_21  TLED_20  TLED_19  TLED_18  TLED_17
3       0          0          0        0        0        0        0        0

Row     50A1       50B1       50C1     50P1     50A2     50B2     50C2     50P2
4       0          0          0        0        0        0        0        0

.
. (131 rows not shown)
.


Row     *          *          *        *        *        *        *        RSTDNPE
135     0          0          0        0        0        0        0        0

=>
```

TEST DB Command

Use the **TEST DB** command to temporarily force the relay to send fixed analog and/or digital values over communications interfaces for protocol testing.

Command	Description	Access Level
TES DB	Display the present status of digital and analog overrides.	B
TES DB A *name value*	Override analog label *name* with *value* in communications interface.	B
TES DB A *row_x value*	Override all Relay Word bits in Relay Word row number *row_x* with *value*.	B
TES DB D *name value*	Override Relay Word bit *name* with *value* (Modbus, DNP, and IEC 61850 only).	B
TES DB *name* **OFF**	Clear (analog or digital) override for element *name*.	B
TES DB OFF	Clear all analog and digital overrides.	B

The **TEST DB** command provides a method to override Relay Word bits or analog values to aid testing of communications interfaces. The command overrides values in the communications interfaces (SEL Fast Message, DNP, Modbus, and IEC 61850) only. The actual values used by the relay for protection and control are not changed. However, remote devices may use these analog and digital signals to make control decisions. Ensure that remote devices are properly configured to receive the overridden data before using the **TEST DB** command.

To override analog data in a communications interface, enter the following from Access Level B or higher:

```
=>>TEST DB A name value <Enter>
```

where *value* is a numerical value and *name* is an analog label from *Table G.1*, Analog Quantities, with an "x" in the DNP, Modbus, Fast Meter, or IEC 61850 column.

AVOID FALSE OPERATIONS
To reduce the chance of a false operating decision when using the **TEST DB** command, ensure that protocol master device(s) flag the data as "forced or test data." One possible method is to monitor the TESTDB Relay Word bit.

NOTE: When using the **TEST DB** command to generate values for Fast Meter testing, you may need to override all current and voltage angles (IAFA, VAYFA, etc.) to ensure the expected phase relationship.

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For example, the **TEST DB** command can be used to force the value of Phase A current magnitude transmitted to a remote device to 100 A:

```
=>>TES DB A IA 100 <Enter>
```

To override digital data in a Modbus, DNP, or IEC 61850 communications interface, enter the following from Access Level B or higher:

```
=>>TES DB D name value <Enter>
```

where *name* is a Relay Word bit (see *Table F.1*) and *value* is 1 or 0.

For example, if Relay Word bit 51PT = logical 0, the **TEST DB** command can be used to effectively force the communicated status of this Relay Word bit to logical 1 to test the communications interface:

```
=>>TES DB D 51PT 1 <Enter>
```

Values listed in the SER triggers SER1, SER2, SER3, and SER4 cannot be overridden.

To override digital data in a Modbus, DNP, SEL Fast Messaging, or IEC 61850 communications interface, enter the following from Access Level B or higher:

```
=>>TES DB A Row_x value <Enter>
```

where *Row_x* is a Relay Word row number (see *Table F.1*) and *value* is 1 to 255 (the integer sum of the individual Relay Word bits to be set).

For example, Relay Word bits 51PR and 51PT are bits 2 and 0, respectively, of Relay Word Row 11. The **TEST DB** command can be used to effectively force the communicated status of these Relay Word bits to logical 1 to test the communications interface:

```
=>>TES DB A Row_11 5 <Enter>
```

where the value of 5 is the integer value to set bits 2 and 0 of the Relay Word row ($2^2 + 2^0 = 5$).

Values listed in the SER triggers SER1, SER2, SER3, and SER4 cannot be overridden.

When the relay is not in Test Mode, the relay responds to either the digital or analog override request with the following message:

```
WARNING:  TEST MODE is not a regular operation.
Communication outputs of the device will be overridden by simulated values.

Are you sure (Y/N)? Y <Enter>
```

The relay responds:

```
Test Mode Active.  Use Test DB OFF command to exit Test Mode.
Override Added
```

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Relay Word bit TESTDB will also assert to indicate that Test Mode is active. If the relay is already in the test mode (overrides are already active), the relay responds:

```
Override Added
```

The **TEST DB** command alone displays the present status of digital and analog overrides. An example **TEST DB** response after two analogs follows:

```
==>TES DB <Enter>

FEEDER 1                        Date: 02/02/09 Time: 16:24:38.764
STATION A                       Time Source:  internal

NAME          OVERRIDE VALUE
IA              100.0000
FREQ             60.0000

==>
```

Individual overrides are cleared by using the **TEST DB** command with the OFF parameter:

```
=>>TES DB D or A name OFF <Enter>
```

Entering **TEST DB OFF** without name will clear all overrides. The relay will automatically exit the Test Mode and clear all overrides if there are no **TEST DB** commands entered for 30 minutes.

TIM Command (View/ Change Time)

TIM displays the relay clock. If a valid IRIG-B or SNTP time synchronization signal is connected to the relay, the **TIM** command cannot be used to set the relay time. See *Configuring High-Accuracy Timekeeping on page J.21* for more details on IRIG time sources.

Command	Description	Access Level
TIM	Display the present internal clock time.	1
TIM *hh:mm*	Set the internal clock to *hh:mm*.	1
TIM *hh:mm:ss*	Set the internal clock to *hh:mm:ss*.	1
TIM Q	Display time statistics.	1
TIM DST	Display daylight-saving time information.	1

NOTE: After setting the time, allow at least 60 seconds before powering down the relay or the new setting may be lost.

Separate the hours, minutes, and seconds with colons, semicolons, spaces, commas, or slashes. To set the clock to 23:30:00, enter:

```
=>TIM 23:30:00 <Enter>
23:30:00
=>
```

If **TIM** is entered with the Q parameter, time statistics are displayed.

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```
=>TIM Q <Enter>

PTR 10000                          Date: 04/27/2012  Time: 12:52:29.272
651R-2                             Time Source: external

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx   CID=4629

UTC: 19:52:29
UTC Offset: -7.00 hrs

Time Source: HIRIG
Last Update Source: HIRIG
Active IRIG Port: BNC

Last Update Time: 19:52:29  04/27/2012

IRIG Time Quality: 0.001 ms

Internal Clock Period: 20.000172 ns
=>
```

Time Source is HIRIG when Relay Word bit TSOK is asserted. Otherwise, Time Source is OTHER. Last Update Source indicates the source of the last time or date update. Valid update sources are HIRIG, IRIG, DNP, MODBUS, SNTP, ASCII DATE, ASCII TIME, FRONT PANEL DATE, and FRONT PANEL TIME. If the relay time was last updated from the battery-backed clock, such as after a loss of power, Last Update Source is NONV CLK.

When at least one source of IRIG-B time signal is connected, Active IRIG Port displays which source is in use (BNC or Port 2).

If setting IRIGC = C37.118 and TIRIG or TSOK is asserted, IRIG Time Quality displays the time error calculated based on information contained in the control fields of the IRIG-B signal (see *Configuring High-Accuracy Timekeeping on page J.21*).

The internal clock period shows the time associated with the processor clock. This time may change slightly when an IRIG signal is connected.

If **TIM** is entered with the DST parameter and daylight-saving time is enabled (see *Automatic Daylight-Saving Time Settings (Global Settings) on page 9.39*), daylight-saving time information is displayed.

```
=>TIM DST <Enter>

12:51:46

Daylight Saving Time Begin Rule: 2nd Sunday of March at 02:00
Daylight Saving Time End Rule:   1st Sunday of November at 02:00

Daylight Saving Time Active

Next Daylight Saving Time Beginning: 03/10/2013 02:00
Next Daylight Saving Time Ending:    11/04/2012 02:00

=>
```

TRI Command (Trigger Event Report)

Command	Description	Access Level
TRI	Trigger an event report data capture.	1
TRI *time*	Trigger an event report data capture at specified *time*.	1
TRI STA	Display the status of a previous **TRI** *time* command.	1

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Issue the **TRI** command to generate an event report:

```
=>TRI <Enter>
Triggered
=>
```

Use the optional *time* parameter to specify the exact time to trigger an event. If *time* is not specified, the event is triggered at the current time. The *time* should be input in 24-hour format (i.e., 15:11:00). If fractional seconds are input, they will be ignored.

```
=>TRI 16:00:00 <Enter>
An event will trigger at 16:00:00
=>
```

Only one **TRI** *time* command may be pending on a single port at any one time. If a **TRI** *time* command is entered while another command is pending, the old request will be canceled and the new request will be pending. **TRI** commands entered without the time parameter will not affect any pending **TRI** *time* commands.

A **TRI STA** command may be used if a **TRI** *time* command is pending.

The following shows the output from an SEL-651R-2:

```
=>TRI STA <Enter>
An event will trigger at 16:00:00
=>
```

If the trigger has already been executed, or no trigger was set, the relay responds as follows:

```
=>TRI STA <Enter>
No trigger time set
=>
```

If the serial port AUTO setting = Y, the relay sends the summary event report:

```
=>
FEEDER 1                                    Date: 08/05/2011  Time: 14:38:27.000
STATION A                                   Time Source: external

Event: TRIG  Location: $$$$$  Shot: 0  Frequency: 60.0
Targets: 10 100000000000 001000000000
Currents (A Pri), ABCGQ:      1     1     1     2     0
=>
```

See *Section 12: Analyzing Events* for more information on event reports.

TRI HIF (Only Available in Relays That Support Arc Sense Technology)

The **TRI HIF** command is used to trigger an HIF event report. The **TRI HIF** command does not support the time or STA parameters. See *High-Impedance Fault (HIF) Event Reporting on page 12.47* for more information on HIF event reports.

Command	Description	Access Level
TRI HIF	Trigger HIF event report data capture.	1

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VEC Command (Show Diagnostic Information)

Issue the **VEC** command only under the direction of SEL.

Command	Description	Access Level
VEC D	Display the standard Vector Report.	2
VEC E	Display the Extended Vector Report.	2

The information contained in a vector report is formatted for SEL in-house use only. Your SEL application engineer or the factory may request a **VEC** command capture to help diagnose a relay or system problem.

VER Command (Show Relay Configuration and Firmware Version)

The **VER** command provides relay configuration and information such as nominal current input ratings.

Command	Description	Access Level
VER	Display information about the configuration of the relay.	1

An example printout of the **VER** command for an SEL-651R-2 follows:

```
=>VER <Enter>

Part Number:  0651R263XAA83A11X3XXXX
Serial Number:  xxxxxxxxxxxxxx

Analog Voltage Inputs (PT):  300 Vac(VY)-300 Vac(VZ)
Analog Current Inputs (CT):  1 Amp Phase, 0.2 Amp Neutral
Main Board I/O:  3 Form C Outputs, 5 Form A Outputs, 7 Inputs

Relay Features:
  Mirrored Bits
  DNP
  Modbus
  IEEE C37.118
  Fast SER
  Power Quality Monitoring
  Tri-Color LEDs
  One 10/100BASE-T Port

SELboot checksum  OK
FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx

BFID=SLBT-3CF1-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx

If above information is unexpected. . .
contact SEL for assistance
=>
```

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Section 11

Front-Panel Operations

Introduction

The SEL-651R-2 Recloser Control front panel makes power system data collection and system control quick and efficient. Use the front panel to analyze power system operating information, view and change recloser control settings, and perform control functions. The SEL-651R-2 features a straightforward menu-driven control structure presented on the front-panel liquid crystal display (LCD). Front-panel targets and other LED indicators give a quick look at SEL-651R-2 operation status. Perform often-used control actions rapidly by using the large direct-action pushbuttons. The features that help you operate the recloser control from the front panel include the following:

➤ Reading metering

➤ Inspecting targets

➤ Accessing settings

➤ Controlling recloser control operations

Front-Panel Layout

Figure 11.1 shows and identifies the following regions:

➤ EIA-232 serial port. See *Section 10: Communications* for details on the serial port.

➤ Human-machine interface (HMI)

➤ Status and trip target LEDs

➤ Operator control pushbuttons and LEDs

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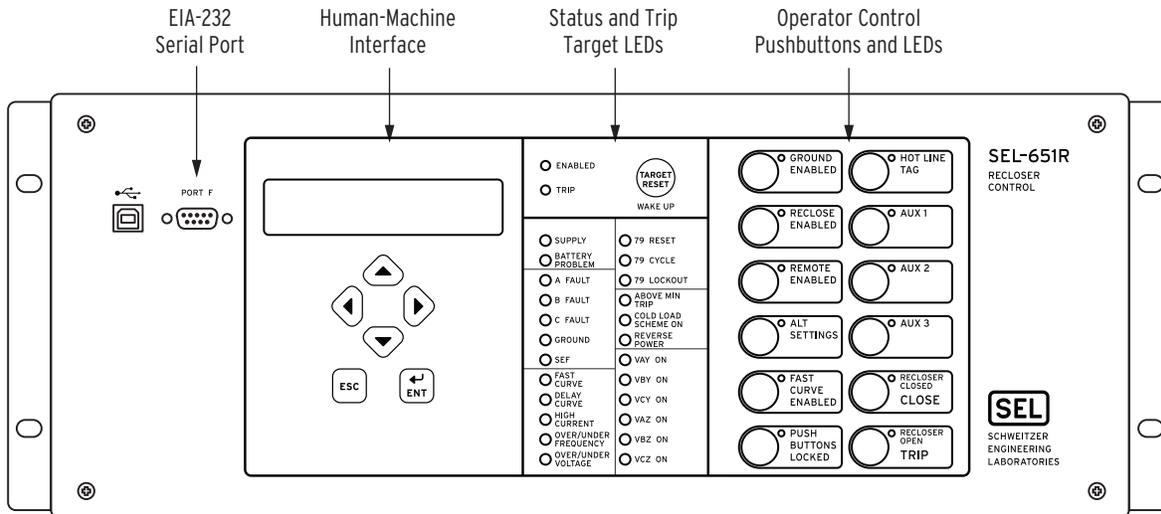
Figure 11.1   SEL-651R-2 Front-Panel Pushbuttons—Overview

This versatile front panel supports the following features so you can customize it for your needs:

➤ Rotating display and control points on the HMI

➤ Programmable status and trip target LEDs

➤ Programmable operator control pushbuttons and LEDs

➤ Slide-in configurable front-panel labels to change the identification of status and trip target LEDs and operator control pushbuttons and LEDs.

Human-Machine Interface

Contrast

NOTE: See the Preface for an explanation of typographic conventions used to describe menus, the front-panel display, and the front-panel pushbuttons.

You can adjust the LCD screen contrast to suit your viewing angle and lighting conditions. To change screen contrast, press and hold the **ESC** pushbutton for two seconds. The SEL-651R-2 displays a contrast adjustment box. Pressing the **Right Arrow** pushbutton increases the contrast. Pressing the **Left Arrow** pushbutton decreases the screen contrast. When you are finished adjusting the screen contrast, press the **ENT** pushbutton; this process is a short cut for changing the LCD contrast setting FP_CONT in the front-panel settings.

Front-Panel Automatic Messages

The recloser control displays an automatic message if a self-test failure occurs.

Front-Panel Security

Front-Panel Access Levels

The SEL-651R-2 front panel typically operates at Access Level 1 and provides viewing of recloser control measurements and settings. Some activities, such as editing settings and controlling output contacts, are restricted to those operators who know the Access Level B or Access Level 2 passwords, or can disable these passwords from the front panel.

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In the figures that follow, restricted activities that require the Access Level B password are marked with the padlock symbol shown in *Figure 11.2*. Restricted activities that require the Access Level 2 password are marked with the padlock symbol with the word Set above it.

Figure 11.2   Access Level Security Padlock Symbol

Before you can perform a front-panel menu activity that is marked with the padlock symbol, you must enter the correct Access Level B or Access Level 2 passwords. After you have correctly entered the password, you can perform other Access Level B or Access Level 2 activities without reentering the password.

Access Level Password Entry

When you try to perform an Access Level B or Access Level 2 activity, the recloser control determines whether you have entered the correct Access Level B or Access Level 2 password since the front-panel inactivity timer expired. If you have not, the recloser control displays the screen shown in *Figure 11.3* for you to enter the password.

Figure 11.3   Password Entry Screen

See *PAS Command (Change Passwords) on page 10.65* for the list of default passwords and for more information on changing passwords.

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Front-Panel Time-Out

To help prevent unauthorized access to password-protected functions, the SEL-651R-2 provides a front-panel time-out, setting FP_TO. A timer is reset every time a front-panel pushbutton is pressed. Once the time-out period has expired, the access level is reset to Access Level 1. Manually reset the access level by selecting `Reset Access Lvl` from the `MAIN` menu.

Front-Panel Menus and Screens

Navigating the Menus

The SEL-651R-2 front panel gives you access to most of the information that the recloser control measures and stores. You can also use front-panel controls to view or modify recloser control settings.

All of the front-panel functions are accessible using the six-button keypad and LCD display. Use the keypad (shown in *Figure 11.4*) to maneuver within the front-panel menu structure, described in detail throughout the remainder of this section. *Table 11.1* describes the function of each front-panel pushbutton.
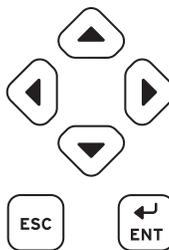
Figure 11.4   Front-Panel Pushbuttons

Table 11.1   Front-Panel Pushbutton Functions

Pushbutton	Function
Up Arrow	Move up within a menu or data list.
	While editing a setting value, increase the value of the underlined digit.
Down Arrow	Move down within a menu or data list.
	While editing a setting value, decrease the value of the underlined digit.
Left Arrow	Move the cursor to the left.
Right Arrow	Move the cursor to the right.
ESC	Escape from the current menu or display.
	Hold for 2 seconds to display contrast adjustment screen.
ENT	Move from the rotating display to the `MAIN` menu.
	Select the menu item at the cursor.
	Select the displayed setting to edit that setting.

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The SEL-651R-2 automatically scrolls information that requires more space than provided by a 16-character LCD line. Use the **Left Arrow** and **Right Arrow** pushbuttons to suspend automatic scrolling and enable manual scrolling of this information.

SEL-651R-2 Menu

Figure 11.5 describes the menu hierarchy. Menus and displays are available for most SEL-651R-2 functions. Several of these menus and displays are described in detail later in this section.

Figure 11.5   SEL-651R-2 Front-Panel Menu Hierarchy

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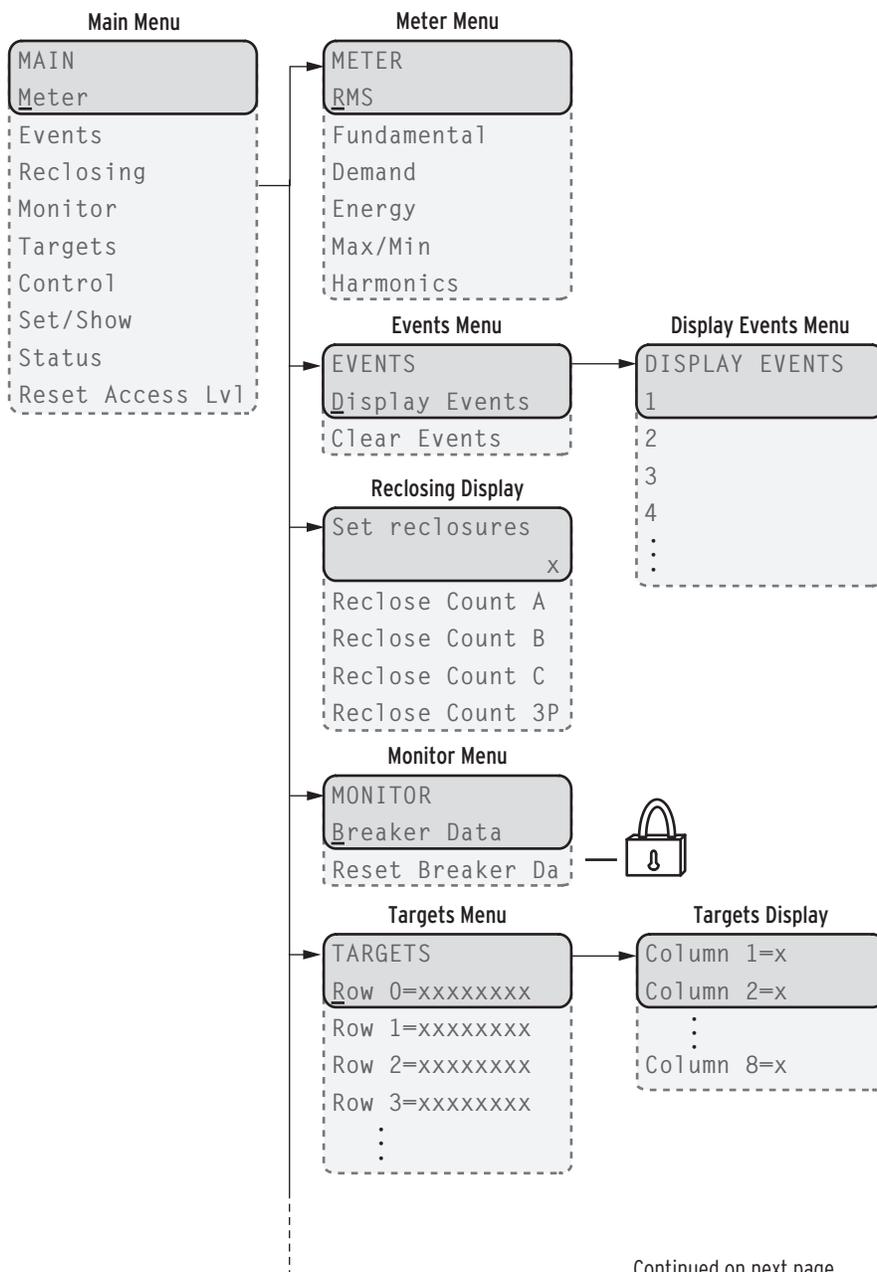
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Figure 11.5 SEL-651R-2 Front-Panel Menu Hierarchy (continued)

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Reclosing Display

Use the RECLOSING display to see the shot counter progression during reclosing relay testing. Select the RECLOSING menu to access this display on the MAIN menu. *Table 11.2* shows example reclosing displays.

Table 11.2   Reclosing Display

The number (2) in the example display corresponds to the last shot value, which is a function of the number of open intervals, setting E79. There are two set open intervals in these example settings, thus two reclosures (shots) are possible in a reclose sequence.	Set Reclosures 2
For three-phase reclosers, the number (0) in the example display corresponds to the present shot value. If the breaker is closed and the reclosing relay is reset, then RECLOSE COUNT = 0. If the breaker is open and the reclosing relay is locked out after a reclose sequence, then RECLOSE COUNT = 2.	Reclose Count 3P 0
For single-phase reclosers, the number (0) in the example displays corresponds to the present shot value for each phase.	Reclose Count A 0
	Reclose Count B 0
	Reclose Count C 0
The example display shows the front-panel LCD when reclosing is disabled.	No Reclosing Set

Targets Menu

Select the TARGETS menu item on the MAIN menu to access the target rows (Relay Word bits). Use the following features to monitor the recloser control during operation and testing.

Navigate to the target row that contains the Relay Word bit you want to access. Monitor two consecutive rows that contain 16 Relay Word bits with this display.	Row 12=01000100 Row 13=10110100
Display the Relay Word bit names and status of two consecutive bits by pressing **ENT** while the cursor is at the row you want to access. Use the **Up Arrow** or **Down Arrow** to navigate to any of the Relay Word bits in the selected row.	51G1S=0 51G1R=1
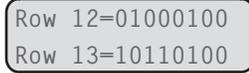
Control Menu

The SEL-651R-2 provides great flexibility in power system control through the Control menu. Use the front-panel Control menu to perform these functions:

➤ Operate local control switches. The output states of these switches are known as local bits.

➤ Test output contacts (password required).

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Local Bits: Menu

Use the local bits menu option to operate as many as 16 local control switches. These local control switches replace traditional panel-mounted control switches. The SEL-651R-2 saves the output states of the local control switches in nonvolatile memory and restores these states at power-up.

> **NOTE:** Any unused local control bits default to the clear (logical 0) state.
>
> Also, any reconfigured local bit retains the existing bit state after you change the bit setting. Disabling a local bit sets that bit to the clear (logical 0) state.
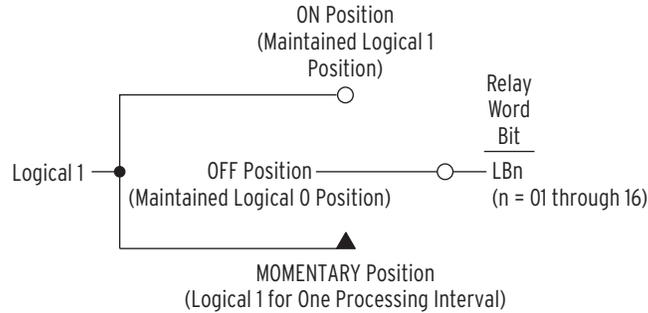
Figure 11.6   OFF/MOMENTARY Local Control Switch

The output of the switch in *Figure 11.6* is a Relay Word bit (LB01–LB16), called a local bit, and repeats for each local bit.

Local Bits: Switch Types

Use the settings in *Table 11.3* to create menu items that aid in using on, off, or momentary switches. Set ELB to the required number of local bits to enable the local bits settings. Use the **SET F** command (see *Table 9.2*).

Table 11.3   Local Bits Labels

Local Bits Switch Position	Label Setting	Setting Definition	Logic State
	NLBn	Name of local bit	
OFF	CLBn	"Clear" local bit LBn	Logical 0
ON	SLBn	"Set" local bit LBn	Logical 1
MOMENTARY	PLBn	"Pulse" local bit LBn	Logical 1 for one processing interval

Setting NLBn, the local bit name, must always contain a valid name. Enter other local bit label settings to configure the local bit switch type in accordance with *Table 11.4*. Enter **NA** to clear a setting.

Table 11.4   Local Bits Switch Configuration

Local Bits Switch Type	Label NLBn	Label CLBn	Label SLBn	Label PLBn
ON/OFF	x	x	x	
OFF/MOMENTARY	x	x		x
ON/OFF/MOMENTARY	x	x	x	x

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ON/OFF Switch.   Local bit LBn can be in the ON (LBn = logical 1) or OFF
(LBn = logical 0) position.
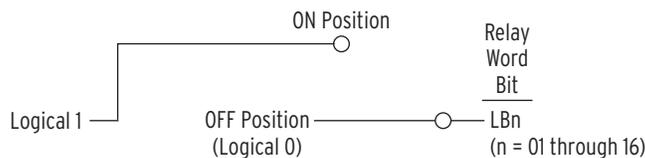
Figure 11.7   ON/OFF Local Control Switch

OFF/MOMENTARY Switch.   Local bit LBn is maintained in the OFF
(LBn = logical 0) position and pulses to the MOMENTARY (LBn = logical 1)
position for one processing interval (1/4 cycle).
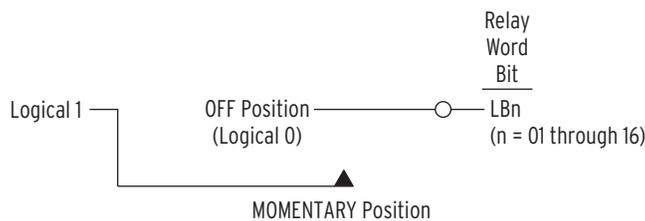
Figure 11.8   OFF/MOMENTARY Local Control Switch

ON/OFF/MOMENTARY Switch.   Local bit LBn can be in the ON
(LBn = logical 1) position, OFF (LBn = logical 0) position, or is maintained in
the OFF (LBn = logical 0) position and pulses to the MOMENTARY
(LBn = logical 1) position for one processing interval (1/4 cycle).
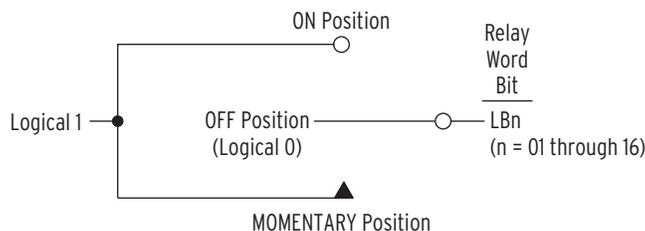
Figure 11.9   ON/OFF/MOMENTARY Local Control Switch

Local Bits: Operation

Table 11.5 shows examples of the local bit displays using setting names.

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Table 11.5   Local Bits Menu

Select the `Local Bits` menu item on the `CONTROL` menu to access the local control switches.	`CONTROL` `Local Bits`
The LCD displays a menu empty of local bits if no local bits are enabled or programmed.	`LOCAL BITS`

The LCD will display a menu of local bits in numerical order if at least one local bit is enabled and programmed. The menu also shows the present position of the local control switches. Use the cursor keys to move to the desired local bit and press **ENT** to select it.	`LOCAL BITS`
	`NLB01 = CLB01`
	`NLB02 = CLB02`
	`⋮`
	`NLB31 = CLB31`
	`NLB32 = CLB32`
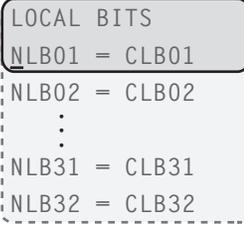
Use the cursor keys to move to the desired position (SLB01, CLB01, or PLB01) and press **ENT** to select that position.	`NLB01 = CLB01`
	`SLB01`
	`PLB01`
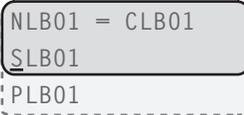
Use the cursor keys to move to `Yes` and press **ENT** to activate that position. The local bit present state updates to the new position.	`SLB01` `No Yes`

Local Bits: Nonvolatile State

The SEL-651R-2 stores local bit states in nonvolatile memory and retains these switch states during power loss. When power is restored, the recloser control restores the local bit states. If a local control switch is in the ON position (corresponding local bit is asserted to logical 1) when power is lost, this switch returns to the ON position (corresponding local bit is still asserted to logical 1) when power is restored. If a local control switch is in the OFF position (corresponding local bit is deasserted to logical 0) when power is lost, this switch returns to the OFF position (corresponding local bit is still deasserted to logical 0) when power is restored. This feature makes the local bit feature behave as a traditional installation with panel-mounted control switches. If power is lost to the panel, the front-panel control switch positions remain unchanged.

If a local bit is routed to a programmable output contact and control power is lost, the SEL-651R-2 stores the state of the local bit in nonvolatile memory but the output contact goes to the de-energized state. When the control power is reapplied to the recloser control, the programmed output contact returns to the local bit state after recloser control initialization.

Local Bits: Application Example

An example of manual trip and close functions using local bits LB03 and LB04 follows. The following label settings configure the local bits as OFF/ MOMENTARY switches (enable local bits first with front-panel setting ELB := 4 or greater).

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Table 11.6   Local Bits Example Settings

Local Bit	Function	Setting
LB03	Name	NLB03 = MANUAL TRIP
	OFF Position	CLB03 = RETURN
	ON Position	SLB03 =
	MOMENTARY Position	PLB03 = TRIP
LB04	Name	NLB04 = MANUAL CLOSE
	OFF Position	CLB04 = RETURN
	ON Position	SLB04 =
	MOMENTARY Position	PLB03 = CLOSE

Use the following steps to change the local bits state.

Select the `Local Bits` menu item on the `CONTROL` menu to access the local control switches.	`LOCAL BITS` `MANUAL TRIP = RE`TURN
Press the **Down Arrow** cursor key to display both the `MANUAL TRIP` and `MANUAL CLOSE` local bits.	`MANUAL TRIP = RE`TURN `MANUAL CLOSE = RE`TURN
Use the cursor keys to select the `MANUAL CLOSE` menu item and press **ENT** to select that item.	`MANUAL CLOSE = RE`TURN `CLOSE`
Use the cursor keys to move to `Yes` and press **ENT** to activate that position. This is an OFF/ MOMENTARY switch; the `MANUAL CLOSE` switch moves momentarily to the `CLOSE` position and then moves back to the `RETURN` position.	`CLOSE` `No Yes`
Press **ESC** to return to the `CONTROL` menu. Use the cursor keys to move to the `MANUAL TRIP` menu item and press **ENT** to select that item.	`MANUAL TRIP = RE`TURN `TRIP`
Use the cursor keys to move to `Yes` and press **ENT** to activate that position. This is an OFF/ MOMENTARY switch; the `MANUAL TRIP` switch moves momentarily to the `TRIP` position and then moves back to the `RETURN` position.	`TRIP` `No Yes`
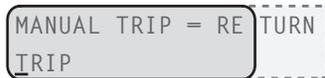
Local Bits: Application Ideas

The preceding settings example is for an OFF/MOMENTARY switch. Local bits configured as ON/OFF switches can be used for other applications, such as the following:

➤ Reclosing relay enable/disable

➤ Ground element enable/disable

➤ Remote control supervision

➤ Sequence coordination enable/disable

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Output Contacts: Menu

Use the `Output Contacts` menu item to test recloser control output contacts and associated circuits. You can pulse trip outputs, close outputs, and general-purpose contact outputs from this menu.

Press the **ENT** pushbutton to pulse the output.	`OUTPUT CONTACTS` `Pulse OUT202`
The LCD displays a password screen if a password is required. Enter your Level B or Level 2 password.	`Password= _` `Del Clr Accept`
Press the **Right Arrow** to select `Yes` and then press **ENT**.	`Pulse OUT202` `No Yes`
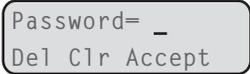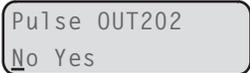
SET/SHOW Menu

The SEL-651R-2 settings are arranged in easy-to-understand categories. The settings structure simplifies setting the recloser control. Access the settings class (group, global, port, or front-panel) and instance (i.e., Group 1, Group 2, etc.) required by performing the following steps, which are similar to issuing the appropriate **SET/SHOW** command:

Step 1. Select the `SET/SHOW` menu item on the `MAIN` menu to view or modify the settings (refer to *SEL-651R-2 Menu on page 11.5*).

Step 2. Select the settings class or select the active group, date/time, or password settings from the `SET/SHOW` menu.

Step 3. If necessary, select an instance of the setting class.

Each settings class includes headings that create subgroups of associated settings. These headings are displayed in the settings screen captures in *Factory-Default Settings on page 9.61*. Select the heading that contains the setting of interest. An example of the GROUP 1 headings is shown in *Figure 11.10*.

```
Identifier and Instrument Transformer Settings:
Enable Settings:
Line Parameter Settings:
...
```

Figure 11.10 GROUP 1 Heading Example

Navigate to the setting of interest. View or edit the setting by pressing **ENT**. For text settings, use the four navigation pushbuttons to scroll through available alphanumeric and special character settings. For numeric settings, use the **Left Arrow** and **Right Arrow** pushbuttons to select the digit to change and the **Up Arrow** and **Down Arrow** pushbuttons to change the value. Press **ENT** to enter the new setting.

Setting changes can also be made by using ACSELERATOR QuickSet SEL-5030 Software or ASCII communications commands.

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Rotating Display

Meters and indicating panel lights can be replaced by the SEL-651R-2 rotating display. This feature rotates screens of information on the LCD when the front-panel menus are not in use.

After front-panel time-out, the LCD presents each of the display screens in the following sequence:

➤ Any active (filled) display points screens

➤ Enabled metering screens

Screen Scrolling

The rotating display has two screen scrolling modes: auto-scrolling mode and manual-scrolling mode.

Press the **ESC** pushbutton while in the `MAIN` menu to enter the rotating display mode. The SEL-651R-2 automatically begins auto-scrolling the enabled metering and display points screens.

Press the **Up Arrow** or **Down Arrow** pushbutton while in the rotating display mode to begin manual scrolling and to navigate to the desired screen. The recloser control remains in manual scrolling mode for 60 seconds, at which time the front-panel LCD resumes auto-scrolling.

The front-panel setting SCROLD determines how long each screen of the rotating display mode is displayed, settable from 1 to 60 seconds.

Press the **ENT** or **ESC** key to exit the rotating display and view the `MAIN` menu.

Display Points

Use the 32 display points to show the status of Relay Word bits or display the value of analog quantities (analog values, settings). Set EDP to the required number of display points to enable the display point settings.

See *Table F.1* for a list of digital quantities that can be used with display points. Select the following:

➤ Relay Word bit

➤ Alias

➤ String to display when bit is set

➤ String to display when bit is cleared

See *Table G.1* for a list of analog quantities that can be used with display points. Select the following:

➤ Analog quantity

➤ Formatting, scaling, and programmable text

Status Indications

Circuit breaker auxiliary contacts, front-panel switches, SCADA contacts, and other devices activate traditional indicating panel lights. These indicators signal conditions, such as the following:

➤ Circuit Breaker or Recloser Open/Closed

➤ Reclosing Relay Enabled/Disabled

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Figure 11.11 shows traditional indicating panel lights wired in parallel with SEL-651R-2 optoisolated inputs. Input IN101 provides circuit breaker status to the recloser control and input IN102 enables/disables reclosing via the following SELOGIC control equation settings:

52A_3P := **IN101** (Circuit breaker status)

79DTL3P := **NOT IN102** (Reclosing Drive-to-Lockout Setting)
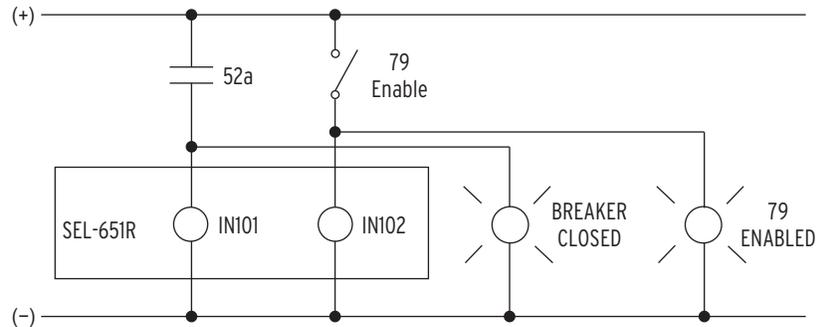
Figure 11.11   Traditional Panel Light Installations

The **79 ENABLED** panel light illuminates when the **79 ENABLE** switch is closed. When the **79 ENABLE** switch is open, the **79 ENABLED** panel light extinguishes, indicating that the reclosing relay is disabled.

The **BREAKER CLOSED** panel light illuminates when the 52a circuit breaker auxiliary contact is closed. When the 52a circuit breaker auxiliary contact is open, the **BREAKER CLOSED** panel light extinguishes and it is understood that the breaker is open.

The indicating panel lights are not needed with the rotating display feature in the SEL-651R-2. *Figure 11.12* shows how to eliminate the indicating panel lights by using the rotating display.
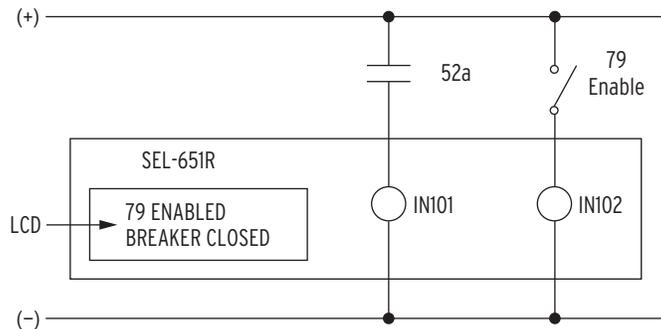
Figure 11.12   Rotating Display Replaces Traditional Panel Light Installations

Setting Syntax

NOTE: DPxx indicates DP01 ... DP32.

Use the following syntax to display the given entry (Relay Word bits or analog quantities) exactly as seen in the navigational menu (name, value, and units).

DPxx := **Name** (see examples later in this section)

Use the following syntax to display the given entry (Relay Word bits or analog quantities) as seen in the navigational menu, replacing the name of the value with the given alias string. Relay Word bits require one row, while analog quantities require two rows.

DPxx := **Name, "Alias"** (see examples later in this section)

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Use the following syntax to display the given entry (Relay Word bits only), with the given alias. If the Relay Word bit is asserted (logical 1), the LCD displays the set string in the place of the value. If the Relay Word bit is deasserted (logical 0), the LCD displays the clear string in the place of the value. One or all of Alias, Set String, or Clear String can be empty. If Alias is empty, then the LCD displays only the Set or Clear Strings. If either Set String or Clear String is empty, then the item is not visible when the bit matches that state. If an empty line is required in this case, instead of hiding the line altogether, then use empty curly braces ({}) for the Set or Clear String. This entry requires at most one display row.

> DPxx := **Name, "Alias", "Set String", "Clear String"** (see examples later in this section)

Use the following syntax to display the given entry (analog quantities only) with the given text and formatting. Formatting must be in the form {Width.Decimal,Scale} with the value of Name, scaled by *Scale*, formatted with total width *Width* and *Decimal* decimal places. The width value includes the decimal point and sign character, if applicable. The scale value is optional; if omitted, the scale factor is processed as 1. If the numeric value is smaller than the field size requested, the field is padded with spaces to the left of the number. If the numeric value will not fit within the field width given, the field grows (to the left of the decimal point) to accommodate the number. All display points formatted in this manner occupy one, and only one, line on the display at all times. You can use multiple display points to simulate multiple lines.

> DPxx := **Name, "Text1 {Width.Decimal,Scale} Text2"** (see examples later in this section)

Relay Word Bits Settings Examples

The following settings examples use optoisolated inputs IN101 and IN102 in the display points settings. Local bits (LB01–LB16), latch bits (LT01–LT16), remote bits (RB01–RB16), settings group indicators (SG1–SG6), and any other Relay Word bits can also be used. These examples use the following syntax:

> DPxx := **Name, "Alias", "Set String", "Clear String"**

Example: Continually Display a Message. To always display the message SEL-651R CONTROL on the rotating display, enter the display point setting DP01 as follows:

Setting	
DP01 := 1, "SEL-651R CONTROL"	SEL-651R CONTROL

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Example: Reclosing Relay Status Indication. Enter SEL~OGIC~ control equation display point setting DP02 as follows to display 79 ENABLED when input IN102 asserts and display 79 DISABLED when IN102 deasserts.

Settings	IN1O2 is Asserted	IN1O2 is Deasserted
DP02 := IN102, , "79 ENABLED", "79 DISABLED"	79 ENABLED	79 DISABLED

Example: Circuit Breaker Status Indication. Use one of the following setting methods to display the circuit breaker status.

Settings	IN1O1 is Asserted	IN1O1 is Deasserted
52A_3P := IN101 DP03 := 52A3P	52A3P=1	52A3P=0
52A_3P := IN101 DP03 := 52A3P, , "BREAKER CLOSED", "BREAKER OPEN"	BREAKER CLOSED	BREAKER OPEN
52A_3P := IN101 DP03 := 52A3P, "BREAKER", "CLOSED", "OPEN"	BREAKER=CLOSED	BREAKER=OPEN

Example: Display Only One Message. Enter settings 52A_3P and DP03 as follows to display BREAKER CLOSED when input IN101 asserts, but display nothing when input IN101 deasserts.

Settings	IN1O2 is Asserted	IN1O2 is Deasserted
52A_3P := IN101 DP03 := 52A3P, , "BREAKER CLOSED"	BREAKER CLOSED	

Analog Quantities Settings Examples

These examples use the following setting syntax:

DPxx := **Name, "Text1 {Width.Decimal,Scale} Text2"**

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Example: Display A-Phase RMS Current.   Set display point DP04 by using one of the following methods to display IA rms current.

Setting	
DP04 := IAR	`IA` `        xxx.x A`
DP04 := IAR, "IA={7.2} A RMS" DP05 := IBR, "IB={7.2} A RMS"	`IA=xxxx.xx A RMS` `IB=xxxx.xx A RMS`
DP04 := IAR, "IA={6.2,0.001} KA RMS" DP05 := IBR, "IB={6.2,0.001} KA RMS"	`IA=xxx.xx KA RMS` `IB=xxx.xx KA RMS`
DP04 := IAR, "A-PH RMS Current"	`A-PH RMS CURRENT` `        xxx.x A`

Example: Display Time-Overcurrent Pickup.   Set display point DP06 by using one of the following methods to display time-overcurrent pickup current:

Setting	
DP06 := 51PJP	`51PJP` `        x.xx A sec`
DP06 := 51PJP, "TOC PICKUP J={3.0}" DP07 := 51PKP, "TOC PICKUP K={3.0}"	`TOC PICKUP J=xxx` `TOC PICKUP K=xxx`
DP06 := 51PJP, "TIMEO/C Pickup J"	`TIMEO/C PICKUP J` `        x.xx A sec`

Example: Display Time-Overcurrent Curve and Time Dial.   Set display points DP07–DP10 by using one of the following methods to display time-overcurrent curve and time dial for a "fast" phase curve (e.g., 51PJC = A, 51PJTD = 0.94) and a "slow" phase curve (e.g., 51PKC = U3, 51PKTD = 13.58).

Setting	
DP07 := 51PJC	`51PJC` `        A curve`
DP08 := 51PJTD	`51PJTD` `  0.94 time dial`

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Setting	
DP09 := 51PKC	51PKC U3 curve
DP10 := 51PKTD	51PKTD 13.58 time dial
DP07 := 51PJC, "fast ph curve = {}" DP08 := 51PJTD, "Fast PH Time DL = {0.2}"	FAST PH CURVE = A FAST PH TIME DL = 0.94
DP09 := 51PKC, "Slow Ph Curve={}" DP10 := 51PKTD, "Slow ph Time dl={0.2}"	SLOW PH CURVE=U3 SLOW PH TIME DL=13.58
DP07 := 51PJC, "fast Curve-phase"	FAST CURVE-PHASE A curve
DP08 := 51PJTD, "fast time Dial-phase"	FAST TIME DIAL-PHASE 0.94 time dial
DP09 := 51PKC, "Slow curve-phase"	SLOW CURVE-PHASE U3 curve
DP10 := 51PKTD, "slow time dial-phase"	SLOW TIME DIAL-PHASE 13.58 time dial

Some of the examples above show text continuing to the right of the front-panel display (longer than the 16 horizontal spaces of the front-panel display). In these display situations, the text will automatically scroll to the left to display all the text.

In the examples above, where all the information for a curve or time dial value is displayed in a single line, note the bracket values {} for curve display settings and {0.2} for time-dial display settings. No other variation of these bracket values is needed for displaying curve or time-dial values, respectively, in a single-line fashion.

Metering Screens

The SEL-651R-2 displays enabled metering screens in the following order:

Setting	
Use setting FPNGD to select IA, IB, IC, IN or IA, IB, IC, IG currents or to disable the screen.	IA=xxxx IB=xxxx IC=xxxx IN=xxxx or IA=xxxx IB=xxxx IC=xxxx IG=xxxx

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Setting	
Use setting FPVYD to enable/disable the Y-Side Voltages screen.	VAY VBY VCY xx.x xx.x xx.xkV
Use setting FPVZD to enable/disable the Z-Side Voltages screen.	VAZ VBZ VCZ xx.x xx.x xx.xkV

Status and Trip Target LEDs

Programmable LEDs

The SEL-651R-2 provides quick confirmation of recloser control conditions via status and trip target LEDs. *Figure 11.13* and *Figure 11.14* show this region with factory-default text on the front-panel configurable labels.
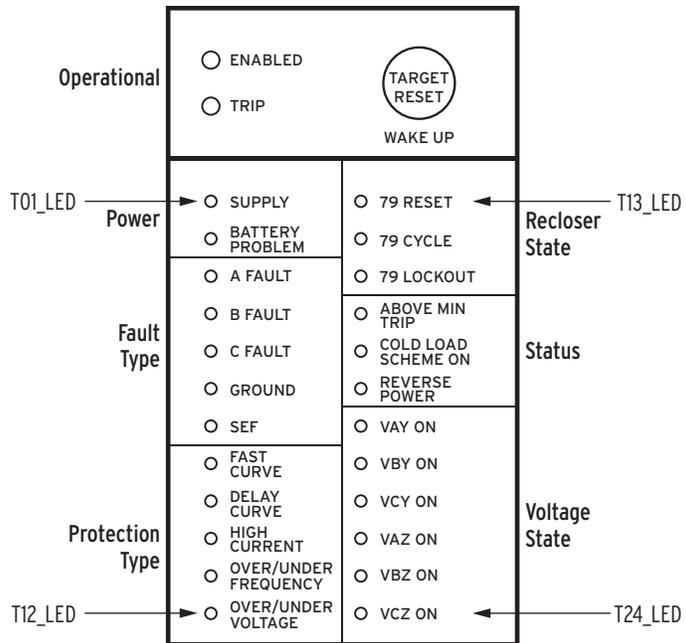
Figure 11.13 Factory-Default Front-Panel LEDs (Dual-Door Enclosure)
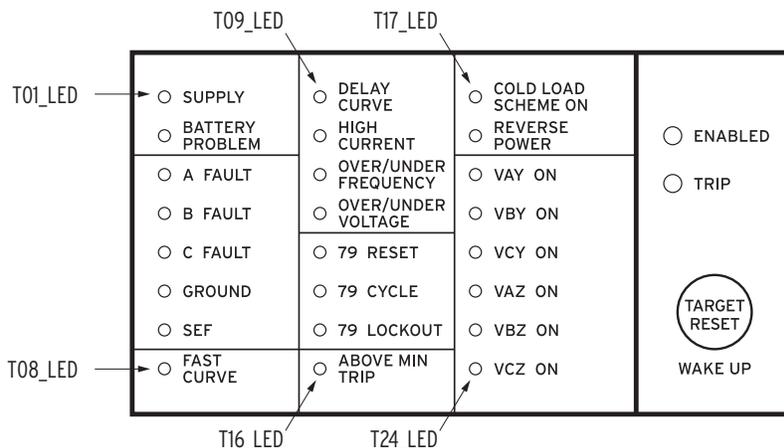
Figure 11.14 Factory-Default Front-Panel LEDs (Single-Door Enclosure)

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Status and Trip Target LEDs

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You can reprogram all of these indicators except the **ENABLED** and **TRIP** LEDs to reflect operating conditions other than the factory-default programming described in this subsection. This front-panel region provides tricolor (red, green, or amber) LEDs for the **ENABLED** and **TRIP** LEDs. Use settings LEDENAC and LEDTRAC to select the assert color. The target LED color setting LEDTRAC (for the **TRIP** LED) is only present when tricolor LEDs are ordered for the SEL-651R-2. If tricolor LEDs are not ordered, the **TRIP** LED is red.

Settings Tn_LED are SELOGIC control equations that, when asserted during a recloser control trip event, illuminate the corresponding LED. Parameter n is a number from 1–24 that indicates each LED. Program setting TnLEDL := Y to latch the LEDs during trip events; when you set TnLEDL := N, trip latch supervision has no effect and the LED follows the state of the Tn_LED SELOGIC control equation. With the tricolor LED option, target LED settings Tn_LEDC select the assert color. After setting the target LEDs, issue the **TAR R** command to reset the target LEDs. For a concise listing of the default programming on the front-panel LEDs, see *Table 5.3*.

The SEL-651R-2 features slide-in labels for custom LED designations that match custom LED logic. Use the slide-in labels to mark the LEDs with these custom names. Included on the SEL-651R-2 Product Literature CD are Configurable Label Templates to print labels for the slide-in label carrier.

The **ENABLED** LED indicates that the recloser control is powered correctly, is functional, and has no self-test failures. Trip events illuminate the **TRIP** LED. The prominent location of the **TRIP** LED in the top target area aids in recognizing trip events quickly. See *Front-Panel Target LEDs ENABLED and TRIP on page 5.15*.

Figure 11.13 shows the arrangement of the status and trip target LEDs region into seven areas. See *Table 11.7* for a description of these areas.

Table 11.7   Target LED Areas

Target LED Area	Description
Operational	**ENABLED**, **TRIP**
Power	**SUPPLY** and **BATTERY PROBLEM** LEDs indicate whether the control is powered from the power supply mains and whether the battery is healthy.
Fault Type	Use these LEDs to determine whether **A FAULT**, **B FAULT**, **C FAULT**, **GROUND**, or **SEF** were involved in the fault.
Protection Type	Use these LEDs to determine whether **FAST CURVE**, **DELAY CURVE**, **HIGH CURRENT**, **OVER/UNDERFREQUENCY**, or **OVER/UNDERVOLTAGE** protection caused the trip.
Recloser State	**79 RESET**, **79 CYCLE**, and **79 LOCKOUT** LEDs indicate the state of the recloser.
Status	**ABOVE MIN TRIP**, **COLD LOAD SCHEME ON**, and **REVERSE POWER** indicate important operating conditions.
Voltage State	**VAY ON**, **VBY ON**, **VCY ON**, **VAZ ON**, **VBZ ON**, and **VCZ ON** LEDs indicate whether the phase voltages are above a programmable threshold.

See *Front-Panel Target LEDs on page 5.13* for additional details on the functionality of these status and trip target LEDs.

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TARGET RESET
Pushbutton

TARGET RESET

For a trip event, the SEL-651R-2 latches the trip-involved target LEDs. Press the **TARGET RESET** pushbutton to reset the latched target LEDs. When a new trip event occurs and the previously latched trip targets have not been reset, the recloser control clears the latched targets and displays the new trip targets. Pressing and holding the **TARGET RESET** pushbutton illuminates all the LEDs. Upon release of the **TARGET RESET** pushbutton, two possible trip situations can exist: the conditions that caused the recloser control to trip have cleared, or the trip conditions remain present at the recloser control inputs. If the trip conditions have cleared, the latched target LEDs turn off. If the trip event conditions remain, the recloser control re-illuminates the corresponding target LEDs.

Lamp Test

The **TARGET RESET** pushbutton also provides a front-panel lamp test. Pressing and holding **TARGET RESET** illuminates all the front-panel LEDs, and these LEDs remain illuminated for as long as **TARGET RESET** is pressed. The target LEDs return to a normal operational state after release of the **TARGET RESET** pushbutton.

Wake Up

Use this pushbutton to reconnect the battery to the recloser control when external power is not present and the recloser control has disconnected the battery. Once the battery has been reconnected, the SEL-651R-2 will automatically initiate its startup sequence and then enable protection. The battery was initially disconnected after external power was removed and the PWRDN_AC (power-off delay after ac loss) timer expired. The battery will be disconnected again when the PWRDN_WU (power-off delay after wake up) timer expires or 15 minutes after the last front-panel pushbutton is pushed, once the timer begins running. Use these timers to manage the remaining battery capacity. See *Battery System Monitor on page 8.39* for more information.

Other Target Reset Options

Use the ASCII command **TAR R** to reset the target LEDs; see *TAR Command (Display Relay Element Status) on page 10.74* for more information. Programming specific conditions in the SELOGIC control equation RSTTRGT is another method for resetting the targets LEDs. Access RSTTRGT in the Global settings (Data Reset Control). See *Section 9: Settings* for further information. The target LEDs can also be reset by performing a target reset through the DNP or Modbus protocols (see *Appendix E: DNP3 Communications* and *Appendix K: Modbus RTU and TCP Communications*.)

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Operator Controls

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Operator Controls

The SEL-651R-2 front panel features large operator control pushbuttons coupled with amber annunciator LEDs for local control. *Figure 11.15* shows this region of the SEL-651R-2 front panel with factory-default text on the front-panel configurable labels.
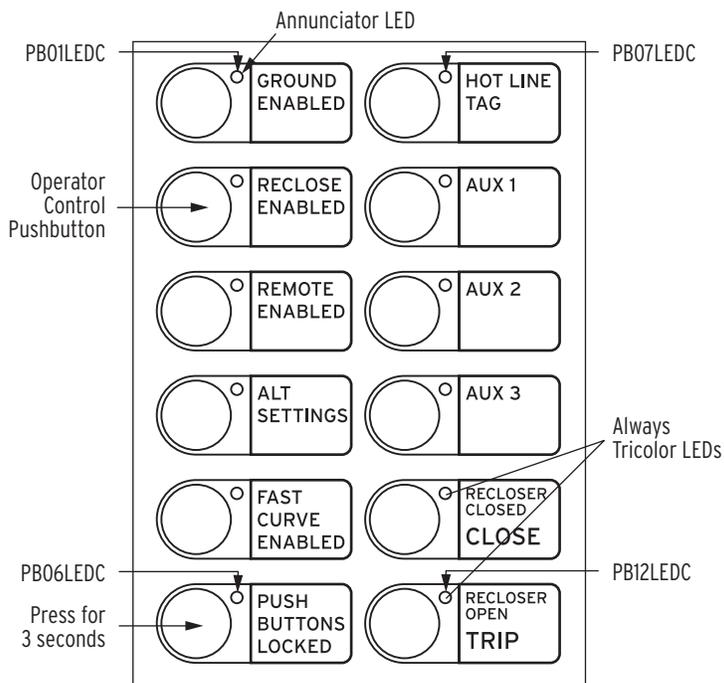
Figure 11.15   Operator Control Pushbuttons and LEDs (Dual-Door Enclosure)
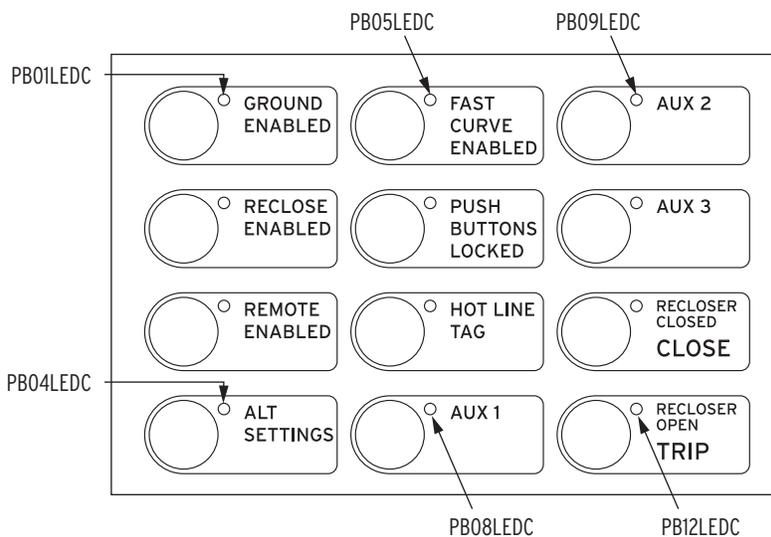
Figure 11.16   Operator Control Pushbuttons and LEDs (Single-Door Enclosure)

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Factory-Default Settings

With the tricolor LED option, pushbutton LED settings PB*n*LEDC select the asserted and deasserted colors.

Factory-default programming associates specific recloser control functions with the 12 pushbuttons and LEDs, as listed in *Table 11.8*. *Table 11.9* describes the factory-default settings for the operator controls.

Table 11.8   Operator Control Pushbuttons and LEDs—Factory Defaults

LED	Pushbutton	Function
GROUND ENABLED	GROUND ENABLED	Enable ground overcurrent tripping
RECLOSE ENABLED	RECLOSE ENABLED	Enable auto reclosing
REMOTE ENABLED	REMOTE ENABLED	Enable remote control
ALT SETTINGS	ALT SETTINGS	Change to alternate settings
FAST CURVE ENABLED	FAST CURVE ENABLED	Enable fast curve
PUSHBUTTONS LOCKED	PUSHBUTTONS LOCKED	Engage/disengage pushbutton lock
HOT LINE TAG	HOT LINE TAG	Enable hot-line tag
AUX 1	AUX 1	Programmable
AUX 2	AUX 2	Programmable
AUX 3	AUX 3	Programmable
RECLOSER CLOSED	CLOSE	Close recloser or circuit breaker
RECLOSER OPEN	TRIP	Open recloser or circuit breaker

Press the operator control pushbuttons momentarily to toggle on and off the functions listed adjacent to each LED/pushbutton combination. This applies to all operator control pushbuttons except the **PUSHBUTTONS LOCKED**, which must be pressed continually for three or more seconds, and the **AUX 1**, **AUX 2**, **AUX 3**, and **REMOTE ENABLED** pushbuttons, which are not programmed with factory-default functionality. The **CLOSE** and **TRIP** pushbuttons momentarily assert the close and trip outputs.

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Table 11.9 Operator Controls (Sheet 1 of 2)

Operator Control Pushbutton	Relay Word Bit Output	SELogic Factory-Default LED Setting and Color	Function
— LED ○ GROUND ENABLED Operator Control Pushbutton	PB01 PB01_PUL	PB01_LED := LT01 PB01LEDC := AO (AO is Amber, Off)	Press the **GROUND ENABLED** operator control pushbutton to enable/disable ground overcurrent element tripping. The corresponding LED illuminates to indicate the enabled state.
○ RECLOSE ENABLED	PB02 PB02_PUL	PB02_LED := LT02 PB02LEDC := AO (AO is Amber, Off)	Press the **RECLOSE ENABLED** operator control pushbutton to enable/disable auto reclosing. The corresponding LED illuminates to indicate the enabled state. The **RECLOSE ENABLED** operator control is overridden by operating the **HOT LINE TAG** operator control in the following scenario: Initial state: **RECLOSE ENABLED** is on or off and **HOT LINE TAG** is off. Action: Press the **HOT LINE TAG** operator control pushbutton. Result: **RECLOSE ENABLED** is off and **HOT LINE TAG** is on. The **RECLOSE ENABLED** operator control is now nonfunctional (remains off). **RECLOSE ENABLED** cannot be turned on again until **HOT LINE TAG** is turned off. Once **HOT LINE TAG** is off, the **RECLOSE ENABLED** operator control is then functional, but remains off until the **RECLOSE ENABLED** operator control pushbutton is pressed again.
○ REMOTE ENABLED	PB03 PB03_PUL	PB03_LED := 0 PB03LEDC := AO (AO is Amber, Off)	Press the **REMOTE ENABLED** operator control pushbutton to enable/disable remote control. The corresponding LED illuminates to indicate the enabled state. **Note:** This operator control does not perform any function with the factory settings.
○ ALT SETTINGS	PB04 PB04_PUL	PB04_LED := NOT(SG1) PB04LEDC := AO (AO is Amber, Off)	Press the **ALT SETTINGS** operator control pushbutton to switch the active settings group between the main settings group (Settings Group 1) and the alternate settings group (Settings Group 2). The corresponding LED illuminates to indicate that the alternate settings group is active.
○ FAST CURVE ENABLED	PB05 PB05_PUL	PB05_LED := LT04 PB05LEDC := AO (AO is Amber, Off)	Press the **FAST CURVE ENABLED** operator control pushbutton to enable/disable the fast curve; this leaves the slow curve enabled. The corresponding LED illuminates to indicate the enabled state.

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Table 11.9 Operator Controls (Sheet 2 of 2)

Operator Control Pushbutton	Relay Word Bit Output	SELOGIC Factory-Default LED Setting and Color	Function
PUSH BUTTONS LOCKED	PB06 PB06_PUL	PB06_LED := NOT(LT05 AND NOT(SV01T AND PB06 AND NOT(SC01QU)) OR NOT(LT05) AND SV01T AND PB06 AND NOT(SC01QU)) PB06LEDC := AO (AO is Amber, Off)	Continually press the **PUSHBUTTONS LOCKED** operator control pushbutton for three (3) or more seconds to engage/disengage the lock function. While this pushbutton is pressed, the corresponding LED flashes on and off, indicating a pending engagement or disengagement of the lock function. The LED illuminates constantly to indicate the engaged state. While the lock function is engaged, the following operator controls are locked in position (assuming factory-default settings): GROUND ENABLED HOT LINE TAG / RECLOSE ENABLED AUX 1 / REMOTE ENABLED AUX 2 / ALT SETTINGS AUX 3 / FAST CURVE ENABLED. While locked in position, these operator controls cannot change state if pressed—the corresponding LEDs remain in the same state. When the lock function is engaged, the **CLOSE** operator control cannot close the breaker, but the **TRIP** operator control can still trip the breaker.
HOT LINE TAG	PB07 PB07_PUL	PB07_LED := NOT(LT06) PB07LEDC := AO (AO is Amber, Off)	Press the **HOT LINE TAG** operator control pushbutton to enable/disable the hot-line tag function. The corresponding LED illuminates to indicate the enabled state. While the hot-line tag function is enabled, no closing or auto reclosing can take place via the control (e.g., the **CLOSE** operator control is inoperative). The **HOT LINE TAG** operator overrides the **RECLOSE ENABLED** operator control (see previous **RECLOSE ENABLED** operator control description).
AUX 1	PB08 PB08_PUL	PB08_LED := 0 PB08LEDC := AO (AO is Amber, Off)	Press the **AUX 1**, **AUX 2**, or **AUX 3** operator control pushbutton to enable/disable user-programmed auxiliary control. Program the corresponding LED to indicate the required state. **Note:** These operator controls do not perform any function with the factory settings.
AUX 2	PB09 PB09_PUL	PB09_LED := 0 PB09LEDC := AO (AO is Amber, Off)	
AUX 3	PB010 PB010_PUL	PB10_LED := 0 PB10LEDC := AO (AO is Amber, Off)	
RECLOSER CLOSED CLOSE	PB011 PB011_PUL	PB11_LED := 52A3P PB11LEDC := RO (RO is Red, Off)	Press the **CLOSE** operator control pushbutton to close the breaker. The corresponding **RECLOSER CLOSED** LED illuminates to indicate the breaker is closed.
RECLOSER OPEN TRIP	PB012 PB012_PUL	PB12_LED := NOT(52A3P) PB12LEDC := GO (GO is Green, Off)	Press the **TRIP** operator control pushbutton to trip the breaker and take the SEL-651R-2 to the lockout state. The corresponding **RECLOSER OPEN** LED illuminates to indicate the breaker is open. If the recloser is a regular Traditional Retrofit recloser, SELOGIC setting PB12_LED can be changed, if desired. See the *Motor-Operated Traditional Retrofit Reclosers on page 2.60* for more detail.

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Behavior of Operator Control Pushbutton Logic Outputs

Refer to the Relay Word Bit Output column in *Table 11.9*. Each operator control pushbutton has two corresponding Relay Word bit outputs. For example, the **GROUND ENABLED** operator control pushbutton has Relay Word bit outputs PB01 and PB01_PUL:

➤ PB01 asserts and remains asserted (= logical 1) as long as the **GROUND ENABLED** operator control pushbutton is pressed.

➤ PB01_PUL asserts to logical 1 for only a processing interval (PB01_PUL "pulses") when the **GROUND ENABLED** operator control pushbutton is initially pressed. PB01_PUL can only "pulse" again if the **GROUND ENABLED** operator control pushbutton is released (not pressed) and then pressed again.

The Relay Word bits corresponding to the other operator control pushbuttons operate similarly.

Custom Settings

Use SELOGIC control equations to change the default pushbutton and LED functions. Use the slide-in labels to mark the pushbuttons and pushbutton LEDs with custom names to reflect any programming changes. The Operator Control Labels are keyed and can be inserted in only one position on the front panel. Included on the SEL-651R-2 Recloser Control Product Literature CD are word processor templates for printing slide-in labels. See SEL-651R-2 Configurable Labels instructions for more information on changing the slide-in labels.

Change the function of the operator control LEDs with settings PB01_LED through PB12_LED, found in the SELOGIC Factory-Default LED Setting and Color column in *Table 11.9*. You can change the LED indications to fit specific control and operational requirements. This programmability allows great flexibility and provides operator confidence and safety, especially in indicating the status of functions that are controlled both locally and remotely. The **RECLOSER CLOSED** and **RECLOSER OPEN** LEDs feature tricolor LEDs. Use settings PB11LEDC and PB12LEDC to select whether the asserted and deasserted colors are red, green, or amber. Additional asserted/deasserted color settings PB01LEDC–PB10LEDC are available when the tricolor option is ordered.

Section 12

Analyzing Events

Introduction

The SEL-651R-2 Recloser Control features numerous reports to analyze power system conditions. The relay provides the following analysis tools:

➤ Standard 15/30/60-Cycle Event Reports

➤ Sequential events recorder (SER) report

➤ Sag/Swell/Interruption (SSI) report

➤ High-Impedance Fault Event Reporting

All four reports are stored in nonvolatile memory, ensuring that a loss of power supply to the SEL-651R-2 module will not result in lost data.

Standard 15/30/60-Cycle Event Reporting

Event reports capture highly detailed information over a relatively brief period of time (15, 30, or 60 cycles). Information stored includes the following:

➤ Date and time of the event report trigger with 1 ms resolution.

➤ Individual sample analog input oscillography (currents and voltages, plus frequency) at 4, 16, 32, or 128 samples per cycle.

➤ Digital element states of all Relay Word bits at 4 samples per cycle and optoisolated inputs as fast as 16 samples per cycle.

➤ Event summary, including the front-panel target states at the time of tripping, fault location, and fault type.

➤ Group, logic, global, and report settings (that were in service when the event was recorded).

➤ 10 µs precision trigger time stamp and relative sample times (available when a high-accuracy IRIG-B time source is connected to the control).

An adjustable prefault recording period allows system conditions to be captured prior to the actual event report trigger. Event reports are stored to nonvolatile memory a short time after an event trigger is processed.

Event reports are useful in commissioning tests, system disturbance analysis, and protective device or scheme performance analysis. ACSELERATOR Analytic Assistant SEL-5601 Software and ACSELERATOR QuickSet SEL-5030 Software can read Compressed ASCII and COMTRADE file format versions of the event report, which contain even more information than the standard ASCII event report. With this software, oscillographic traces and digital element traces can be produced on the PC display. A phasor analysis screen allows the protection engineer to analyze the prefault, fault, and post-fault intervals, observing both the directly measured inputs, as well as the calculated sequence component signals.

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Standard 15/30/60-Cycle Event Reports

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Sequential Events Recorder (SER)

The SER report captures detailed digital element state changes over a long time period. Programmable trigger lists allow as many as 96 Relay Word bits to be monitored, in addition to the automatically generated triggers for recloser control startup, settings changes, and active settings group changes. State changes are time-tagged to the nearest millisecond.

SER report data are useful in commissioning tests and during operation for system monitoring and control.

SER information is stored when state changes occur.

Sag/Swell/Interruption (SSI) Report

NOTE: SSI is not available on models ordered with a single voltage input.

The SSI report captures power quality data related to voltage disturbances over a long period of time. Data captured includes the magnitude of currents, one set of three-phase voltages, a reference voltage, and the status of the voltage sag/swell/interrupt (VSSI) Relay Word bits (see *Voltage Sag, Swell, and Interruption Elements on page 4.59*).

SSI report information is useful for analyzing power quality disturbances, or protective device actions that last longer than the time window of a conventional event report.

The SSI recording rate varies from fast to slow, depending on changes in the triggering elements. SSI data are stored to nonvolatile memory just after this information is generated.

High-Impedance Fault Event Reporting

HIF event information is available when the relay supports HIF detection. The relay provides user-programmable event report sizes and triggering conditions; stores a historical summary of HIF events with summary information available of each individual event; and generates Compressed ASCII and COMTRADE file format event reports to display analog data and the state of related Relay Word bits from the nonharmonic HIF fault detection and load reduction algorithms. HIF event data are stored to nonvolatile memory. Use QuickSet and AC SELERATOR Analytic Assistant SEL-5601 Software to collect and analyze event data for HIF alarm and fault conditions.

Standard 15/30/60-Cycle Event Reports

See *Figure 12.8* for an example event report. Note that *Figure 12.8* is on multiple pages.

Filtered and Unfiltered Event Reports

The SEL-651R-2 samples the basic power system measurands (ac voltage and ac current) 128 times per power system cycle. The recloser control filters the measurands at 32 samples-per-cycle to remove transient signals. The recloser control operates on the filtered fundamental values and reports them in the event report.

To view the raw inputs to the recloser control, select the unfiltered event report (e.g., **CEV R**). Use the unfiltered event reports to observe:

➤ Power system transients on channels IA, IB, IC, IN, VAY, VBY, VCY, VAZ, VBZ, and VCZ.

➤ Decaying dc offset during fault conditions on channels IA, IB, and IC.

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➤ Voltage transducer response to power system transients.

➤ Power system harmonics (with appropriate analytical PC software tools).

➤ For unfiltered event reports (e.g., **CEV R**), optoisolated input contact bounce on channels IN101–IN107 and IN201–IN206 updated at 16 samples per cycle.

The filters for ac current and voltage are fixed. You can adjust the optoisolated input debounce via debounce settings (see *Figure 7.17* and *Figure 7.18*).

Current and Voltage Connection Settings: Effect on Event Reports

The Global settings IPCONN, EGNDSW, CTPOL, VYCONN, VZCONN, EPHANT, VSELECT, and FSELECT are fully described in *Settings Explanations on page 9.27*. These settings are briefly presented in this section to allow their effects on the event report analog values to be explained.

The IPCONN setting controls which of the three current input terminals (I1, I2, and I3) gets routed to each of the internal analog channels IA, IB, and IC. This feature is called phase rolling for the current channels, and it allows system phasing and current transformer (CT) connections to be matched inside the SEL-651R-2 without the need to rewire. All SEL-651R-2 event reports display the rolled current values.

GLOBAL SETTING EGNDSW
See Ground Switch Logic on page 4.76.

The EGNDSW setting selects the function of the neutral (IN) channel. When the IN channel is connected to a zero-sequence current source, such as the standard residual connection with terminals I1, I2, and I3, set EGNDSW := Y. In this state, the IG column in SEL-651R-2 event reports will automatically switch between displaying the IN channel data for small signals and the calculated (residual) $3I_0$ data for large signals, such as most ground faults.

Relay Word bit GNDSW captures the IG source for each row of the event report: when GNDSW = logical 1, IG = IN; when GNDSW = logical 0, IG = calculated $3I_0$. Setting EGNDSW := N disables the "ground switch" feature, and the IG column will always display the calculated $3I_0$ data (and GNDSW is permanently = logical 0).

The CTPOL setting allows the current phase polarity to be reversed to facilitate utility or industrial metering direction preferences, without the need to disconnect and reconnect CT wires. In the SEL-651R-2 event reports, channels IA, IB, and IC are always affected by the CTPOL setting. Channel IN is only affected by the CTPOL setting when Global setting EGNDSW := Y.

The VYCONN setting controls which of the three Y-terminal voltage inputs (V1Y, V2Y, and V3Y) get routed to each of the internal analog channels VAY, VBY, and VCY. The VZCONN setting performs a similar function with the V1Z, V2Z, V3Z terminals and VAZ, VBZ, VCZ channels.

This feature is called phase rolling for the voltage channels, and it allows system phasing and potential transformer (PT) connections to be matched inside the SEL-651R-2 without the need to rewire. All SEL-651R-2 event reports display the rolled voltage values.

NOTE: All 6 voltage terminals are represented in the event report analog channels, even if VYCONN and/or VZCONN is set to contain fewer than three phase letters. See Figure 9.21 for further detail.

The EPHANT setting allows three-phase metering to be performed with only a single PT connected. The EPHANT setting has **no effect** on event reports— it is only used in the metering functions (see *Phantom Voltage Function on page 8.4*).

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The VSELECT setting designates which set of input terminals (VY or VZ) are used in various recloser control functions. The only effect VSELECT has on event reports is to determine which set of voltages (VAY, VBY, VCY; or VAZ, VBZ, VCZ) is used in the fault locator function.

The FSELECT setting determines which voltage input is used for frequency measurement and frequency tracking (see *Frequency Source Selection Setting (FSELECT) on page 9.33*). The frequency column in the event report and event summary is affected by this setting.

Event Report Length (Settings LER and PRE)

The SEL-651R-2 provides user-selectable event report length and prefault length. Event report length is either 15, 30, or 60 cycles. Prefault length ranges from 1 to 59 cycles, depending upon LER setting (see *Table 12.1*). Prefault length is the first part of the total event report length (LER) and precedes the event report triggering point.

Raw event reports display one extra cycle of data at the beginning of the report (or two extra cycles when 128 samples per cycle is specified).

Set the prefault length with the PRE setting. See the **SET R** command in *Table 9.2* and corresponding *Report Settings on page SET.64* for instructions on setting the LER and PRE settings.

Changing the LER setting erases all events stored in nonvolatile memory. Changing the PRE setting has no effect on the stored reports.

Event Report Capacity

NOTE: During testing, be aware that once the relay event report memory is full, triggering a new event can displace the oldest events.

The event report capacity depends on the selected event report length (LER) setting, as shown in *Table 12.1*.

Table 12.1   Event Report Length Settings

LER Setting	Prefault Length (PRE setting) Range	Number of Event Reports Stored
15 cycles (factory default)	1–14	40
30 cycles	1–29	25
60 cycles	1–59	15

The SEL-651R-2 stores event reports in nonvolatile memory soon after the events are captured. If the power supply is interrupted during the saving of an event report, the relay reports `Invalid Data` for the event that was not fully stored.

Event Report Triggering

The recloser control triggers (generates) a standard event report when any of the following occur:

➤ Relay Word bit TRIP3P, TRIPA, TRIPB, or TRIPC asserts

➤ Programmable SELOGIC control equation setting ER asserts to logical 1 (in Report settings)

➤ **TRI** (Trigger Event Reports) serial port command executed

➤ Output contacts OUT101–OUT108, OUT201, or OUT202 are pulsed via the serial port or front-panel **PUL** (Pulse Output Contact) command

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Relay Word Bits TRIP3P, TRIPA, TRIPB, TRIPC

Refer to *Figure 5.1*. If Relay Word bit TRIP3P, TRIPA, TRIPB, or TRIPC asserts to logical 1, an event report is automatically generated. Thus, any condition that causes a trip does **not** have to be entered in SELOGIC control equation setting ER.

For example, SELOGIC control equation trip setting TR3P is unsupervised. Any trip condition that asserts in setting TR3P causes the TRIP3P Relay Word bit to assert immediately. The factory-default setting for trip setting TR3P is:

> TR3P := **51PT OR 51G1T OR PB12_PUL OR OC3**

If any of the individual conditions 51PT, 51G1T, PB12_PUL, or OC3 assert, Relay Word bit TRIP3P asserts, and an event report is automatically generated. Thus, these conditions do **not** have to be entered in SELOGIC control equation setting ER.

Relay Word bit TRIP3P (in *Figure 5.1*) is usually assigned to an output for tripping a recloser (such as SELOGIC control equation setting RCTR1 := TRIP3P, in Group settings).

Programmable SELOGIC Control Equation Setting ER

The programmable SELOGIC control equation event report trigger setting ER is set to trigger standard event reports for conditions other than trip conditions (see *Report Settings on page SET.64*). When setting ER detects a logical 0 to logical 1 transition, it generates an event report (if the SEL-651R-2 is not already generating a report that encompasses the new transition). The factory-default setting is:

> ER := **R_TRIG 51P OR R_TRIG 51G1**

The elements in this example setting are:

> 51P Maximum phase current above pickup setting 51PJP or 51PKP for phase time-overcurrent element 51PT (see *Figure 4.16*).

> 51G1 Ground current above pickup setting 51G1JP or 51G1KP for residual ground time-overcurrent element 51G1T (see *Figure 4.22* or *Figure 4.23*).

Note the rising edge operator R_TRIG in front of each of these elements. See *R_TRIG Operator on page 7.5* for more information on rising edge operators and SELOGIC control equations in general.

Rising edge operators are especially useful in generating an event report at fault inception and then generating another later if a breaker failure condition occurs. For example, at the inception of a ground fault, pickup indicator 51G1 asserts and an event report is generated:

> ER := **... OR R_TRIG 51G1 OR ... = logical 1** (for one processing interval)

Even though the 51G1 pickup indicator will remain asserted for the duration of the ground fault, the rising edge operator R_TRIG in front of 51G1 (R_TRIG 51G1) causes setting ER to be asserted for only one processing interval.

Falling edge operators F_TRIG are also used to generate event reports. See *F_TRIG Operator on page 7.6* for more information on falling edge operators.

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Standard 15/30/60-Cycle Event Reports

TRI (Trigger Event Report) and PUL (Pulse Output Contact) Commands

The sole function of the **TRI** serial port command is to generate event reports, primarily for testing purposes.

The **PUL** command asserts the output contacts for testing purposes or for remote control. If output contact OUT101–OUT108, OUT201, or OUT202, asserts via the **PUL** command, the recloser control triggers a standard event report. The **PUL** command is available at the serial port and the recloser control front panel via `MAIN > Control > Output Contacts`.

See *Section 10: Communications* for more information on the **TRI** (Trigger Event Report) and **PUL** (Pulse Output Contact) commands. See *Control Menu on page 11.7* for front-panel-initiated output contact testing.

Back-to-Back Event Report Capability

The SEL-651R-2 is capable of recording successive "back-to-back" event reports for as many as 300 cycles. When back-to-back events are triggered, the relay shortens the prefault portion of the latter event report(s).

Figure 12.1 shows an example of back-to-back event report behavior with factory-default Global settings LER := 15 cycles and PRE := 4 cycles. When the first event report is triggered, the relay records data from 4 cycles before the trigger to 11 cycles after the trigger. An additional event report trigger received during the 15-cycle event report time is ignored. The next event report trigger received after the end of the 11-cycle post-trigger recording period is processed in one of two ways:

➤ If the next trigger processed is within the 4-cycle (PRE) period from the end of the previous event report, the second event report shall contain fewer than 4 cycles of pretrigger data, and the second event report analog data shall be a continuation of the first event report.

➤ If the next trigger is processed beyond the 4-cycle (PRE) period from the end of the previous event report, the second event report shall contain the usual 4 cycles of PRE data, and there will be an unrecorded period between the event reports.

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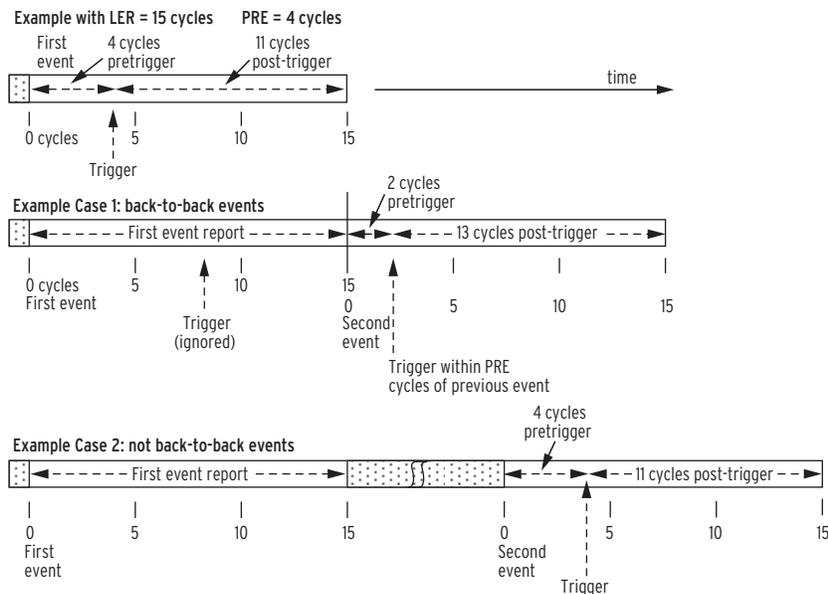
Figure 12.1 Example Behavior for Back-to-Back Event Reports

Event Summaries

Each time the recloser control generates a standard event report, it also generates a corresponding event summary (see *Figure 12.2*). Event summaries contain the following information:

➤ Recloser control and terminal identifiers (settings RID and TID)

➤ Date and time when the event was triggered

➤ Event type

➤ Fault location

➤ Recloser shot count at the trigger row of the event report

➤ System frequency at the start of the event report

➤ Front-panel fault targets at the time of trip

➤ Phase (IA, IB, IC), ground ($I_G = 3I_0$), and negative-sequence ($3I_2$) current magnitudes in amperes primary measured at the largest phase current magnitude in the triggered event report

The recloser control includes the event summary in the standard event report. The identifiers, date, and time information is at the top of the standard event report, and the other information follows at the end. See *Figure 12.8*.

The example event summary in *Figure 12.2* corresponds to the full-length standard 15-cycle event report in *Figure 12.8*.

```
FEEDER 1                        Date: 03/20/2012 Time: 15:21:36.005
STATION A                       Time Source: internal

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx CID=xxxx

Event: BG  Location:   3.02  Shot: 0  Frequency:  60.01
Targets: 11 100101001000 001000000111
Currents (A Pri), ABCGQ:    400 3320    377 3019 3032
```

Figure 12.2 Example Event Summary

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Standard 15/30/60-Cycle Event Reports

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The recloser control sends event summaries to all serial ports with setting AUTO := Y each time an event triggers.

Event Type

The `Event:` field shows the event type. The possible event types and their descriptions are shown in *Table 12.2*. Note the correspondence to the preceding event report triggering conditions (see *Event Report Triggering on page 12.4*).

Table 12.2   Event Types

Event Type	Description
AG, BG, CG	Single phase-to-ground faults. Appends T if TRIPp[a] asserted.
ABC	Three-phase faults. Appends T if TRIPp[a] asserted.
AB, BC, CA	Phase-to-phase faults. Appends T if TRIPp[a] asserted.
ABG, BCG, CAG	Phase-to-phase-to-ground faults. Appends T if TRIPp[a] asserted.
TRIP	Assertion of Relay Word bit TRIPp[a] (phase involvement is indeterminate, so just TRIP is displayed).
ER	SELOGIC control equation setting ER. Phase involvement is indeterminate.
TRIG	Execution of **TRIGGER** command.
PULSE	Execution of **PULSE** command.

[a] p = A, B, C, or 3P.

The event type designations AG–CAG in *Table 12.2* are only entered in the `Event:` field if the fault type is determined successfully. If the fault type is not determined successfully, just TRIP or ER is displayed.

Fault Location

NOTE: The fault locator will not operate properly unless three-phase voltages are connected.

NOTE: The fault locator is most accurate when the fault currents last longer than two cycles.

The recloser control reports the fault location if the EFLOC setting := Y and the fault locator operates successfully after an event report is generated. If the fault locator does not operate successfully, or if EFLOC := N, $$$$$$ is listed in the field. Fault location is based upon the line impedance settings Z1MAG, Z1ANG, Z0MAG, and Z0ANG; and corresponding line length setting LL (see *Line Length (Group Setting) on page 9.49* and *Line Impedance Conversions (Group Settings) on page 9.50* and *Line Parameter Settings on page SET.10*).

Fault Detector Elements

The fault locator algorithm uses the overcurrent elements 50P1–50P4, 51P, 51A, 51B, 51C, 50G1–50G4, 51G1, 51G2, 50Q1T, 50Q2T, 50Q3T, 50Q4T, and 51Q as fault detectors. If any of these elements are set to low pickup values for use as load indicators, they may be asserted during nonfault conditions. In this situation, even though these elements are not being used for tripping the relay, they may still affect the operation of the fault locator, because the start of the disturbance may be unclear. If load detectors are required in your application, use the highest-numbered instantaneous overcurrent elements 50P5, 50P6, 50N5, 50N6, 50G5, 50G6, 50Q5, or 50Q6, because these are not used by the fault locator algorithm.

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Fault Locator Operating Window

NOTE: Do not use the phase overcurrent elements discussed in Section 4: Protection Functions for load current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load current levels, so that the fault locator will work correctly. Use the 50L element instead for load current detection (see Figure 5.6).

NOTE: Do not use the ground- and negative-sequence overcurrent elements discussed in Section 4: Protection Functions for load unbalance current detection if the fault locator is enabled (setting EFLOC := Y). Set these elements above load unbalance current levels so that the fault locator will work correctly.

The SEL-651R-2 uses a 15-cycle subset of the event report data to calculate the event type and fault location. For Global setting LER = 30 and LER = 60, the relay processes the portion of stored data that includes the event report trigger. For LER = 15, the entire event report is available for calculation of the event type and fault location. The relay calculates fault location by using a number of event report rows from the 15-cycle subset. When the fault evolves, the fault location is calculated using rows that represent the predominant fault type.

It is possible for the event type or fault location to be calculated from a different portion of the event report than expected. For example (with default settings), when the event report is first triggered by overcurrent element pickup (ER := R_TRIG 51P OR R_TRIG 51G1), but the trip occurs more than 12 cycles later, the conditions at the time of trip are not considered (unless covered by a new event report). If the fault type changed between pickup and tripping, the event type may not match the front-panel target LEDs. See *Front-Panel Target LEDs on page 5.13* for details on the target LED operation.

Shot Count

NOTE: The SEL-651R-2 uses the trigger row to determine the shot count for event reports. This is different than legacy SEL-651R recloser controls.

When three-phase reclosing is enabled, the SEL-651R-2 reports the reclosing recloser control shot count present at the trigger row of the event report. When single-phase reclosing is enabled, the SEL-651R-2 reports the highest reclosing recloser control shot count present at the trigger row of the event report. When the reclosing recloser control is defeated, the shot count field contains a blank.

Targets

The recloser control reports the targets from the last row of the event report. The targets are displayed in binary format. The order of the binary targets is shown in *Figure 12.3* and *Table 12.3*. See Front-Panel LEDs in *Table 5.3* and *Figure 11.13*.

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Table 12.3   Target LED Relay Word Bits and Binary Target Positions

Left-Hand Target Column of SEL-651R-2			Right-Hand Target Column of SEL-651R-2		
Relay Word Bit of LED	SELOGIC Setting	Binary Target Position	Relay Word Bit of LED	SELOGIC Setting	Binary Target Position
EN	N/A	L1			
TRIPLED	N/A	L2			
TLED_01	T01_LED	1	TLED_13	T13_LED	13
TLED_02	T02_LED	2	TLED_14	T14_LED	14
TLED_03	T03_LED	3	TLED_15	T15_LED	15
TLED_04	T04_LED	4	TLED_16	T16_LED	16
TLED_05	T05_LED	5	TLED_17	T17_LED	17
TLED_06	T06_LED	6	TLED_18	T18_LED	18
TLED_07	T07_LED	7	TLED_19	T19_LED	19
TLED_08	T08_LED	8	TLED_20	T20_LED	20
TLED_09	T09_LED	9	TLED_21	T21_LED	21
TLED_10	T10_LED	10	TLED_22	T22_LED	22
TLED_11	T11_LED	11	TLED_23	T23_LED	23
TLED_12	T12_LED	12	TLED_24	T24_LED	24

The sample target data presented in *Figure 12.3* indicate that **EN** and **TRIP** LEDs were asserted in the last row of the event report, plus the programmable targets TLED_01, TLED_04, TLED_05, TLED_06, TLED_09, TLED_15, TLED_16, TLED_19, TLED_20, and TLED_21.

Binary Target Position	L1	L2		1	2	3	4	5	6	7	8	9	10	11	12		13	14	15	16	17	18	19	20	21	22	23	24
Sample Target Data	1	1		1	0	0	1	1	1	0	0	1	0	0	0		0	0	1	1	0	0	1	1	1	0	0	0

Figure 12.3   Event Summary Targets' Correspondence to Front-Panel Targets

Currents

The `Currents (A pri), ABCGQ:` field shows the currents present in the event report row containing the maximum phase current. The listed currents are:

Phase (A = channel IA, B = channel IB, C = channel IC)

Ground ($I_G = 3I_0$; calculated from channels IA, IB, and IC; or I_G = channel IN; depending on the state of the GNDSW Relay Word bit in the peak current row. See *Ground Switch Logic on page 4.76*.)

Negative-sequence ($Q = 3I_2$; calculated from channels IA, IB, and IC)

Event History (HIS)

The event history gives you a quick look at recent recloser control activity. The recloser control labels each new event in reverse chronological order with 1 as the most recent event. If the **E** parameter is used with the **HIS** command, the event number is replaced by a unique event identification number from 10000 to 65535 (see *HIS Command (Event Summaries/History) on page 10.54* for details). The unique identifier increments by 1 for each new event. See *Figure 12.4* for a sample event history.

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The event history contains the following:

➤ Standard report header

➢ Recloser control and terminal identification

➢ Date and time of report

➤ Event number or unique event identification

➤ Event date and time

➤ Event type

➤ Location of fault (if applicable)

➤ Maximum phase current from summary fault data

➤ Power system frequency at start of event report

➤ Active group at the trigger instant

➤ Reclosing recloser control shot count (same as standard Event Report Summary)

➤ Targets

Figure 12.4 is a sample event history from a terminal.

```
=>>HIS <Enter>

MOUNTAIN F-22                         Date: 07/02/2003  Time: 17:06:52.064
P180                                  Time Source: internal

#     DATE        TIME        EVENT LOCAT   CURR FREQ GST        TARGETS
                                                      RHR   COLUMN 1      COLUMN 2
1   07/02/2003 17:06:35.965 BG     3.02  3320 60.0 101 100101001000 001000000111
2   06/18/2003 13:45:49.020 TRIG  $$$$$   291 60.0 100 100000000000 100000111111

=>

=>>HIS E <Enter>

MOUNTAIN F-22                         Date: 07/02/2003  Time: 17:06:41.141
P180                                  Time Source: internal

#     DATE        TIME        EVENT LOCAT   CURR FREQ GST        TARGETS
                                                      RHR   COLUMN 1      COLUMN 2
10001 07/02/03 17:06:35.965 BG     3.02  3320 60.0 101 100101001000 001000000111
10000 06/18/03 13:45:49.020 TRIG  $$$$$   291 60.0 100 100000000000 100000111111
```

Unique Event Number | Event Number | Event Type | Maximum Current | Active Settings Group | Shot Count | Target LEDs (See Table 12.3 and Figure 12.3)

Figure 12.4 Sample Event History

Fault location data can be indeterminate (for example, when you trigger an event and there is no fault on the power system). If this is the case, the recloser control displays $$$$.$$ for the location entry in the event history. The SEL-651R-2 also displays $$$$.$$ if the fault location enable setting EFLOC := N.

The event types in the event history are the same as the event types in the event summary. See *Table 12.2* for event types.

Viewing the Event History

Access the history report from the communications ports or the Human Machine Interface. View and download history reports from Access Level 1 and higher. You can also clear or reset history data from Access Levels 1 and higher. Clear/reset history data at any communications port.

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Use the **HIS** command from a terminal to obtain the event history. You can specify the number of the most recent events that the recloser control returns. See *HIS Command (Event Summaries/History) on page 10.54* for information on the **HIS** command.

Use the front-panel `MAIN > Events > Display Events` menu to display event history data on the SEL-651R-2 LCD (see *Figure 11.5*).

Use the QuickSet software to retrieve the recloser control event history. View the Recloser Control Event History dialog box via the **Analysis > Get Event Files** menu (see *QuickSet Event Analysis on page 3.18*).

Clearing Standard Event Report Buffer

Via SEL ASCII

The **HIS C** command clears the event summaries and corresponding standard event reports from nonvolatile memory. The **HIS C** command does not reset the unique event identification number to 10000. See *Section 10: Communications* for more information on the **HIS** (Event Summaries/History) command.

Via DNP or Modbus

The DNP binary output DRST_HIS can be used to reset the event summaries and corresponding standard event reports from nonvolatile memory, and is similar in function to the **HIS C** command. See *Appendix E: DNP3 Communications* for more details.

The Modbus protocol can be used to reset the event summaries and corresponding standard event reports from nonvolatile memory, with functions similar to the **HIS C** command. Two methods are available:

➤ Writing to the Reset History Data output coil.

➤ Writing a specific analog value to the RSTDAT register.

See *Appendix K: Modbus RTU and TCP Communications* for details.

Reset Via SELOGIC Control Equation

The Global setting RST_HIS SELOGIC control equation setting can be used to reset the event summaries and corresponding standard event reports from nonvolatile memory. The relay resets the function when the setting first asserts (rising edge, e.g., a logical 0 to a logical 1 transition).

Accessing Event Reports

The relay generates event reports to display analog data, digital data, and relay settings. The event reports provide a complete description of the data that the relay recorded in response to an event trigger. The standard event reports in the SEL-651R-2 can be retrieved in the following formats:

➤ COMTRADE File Format Reports

➤ ASCII Format Report

  ➢ Event Reports (EVE)

  ➢ Compressed Event Reports (CEV)

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Use a terminal or SEL-supplied PC software to retrieve event report files stored in the relay and transfer these files to your computer. Both QuickSet and Analytic Assistant read the compressed and binary event files that the relay generates for an event. See *QuickSet Event Analysis on page 3.18* for instructions on viewing event report oscillography with QuickSet.

COMTRADE File Format Event Reports

The SEL-651R-2 stores high-resolution raw data oscillography in binary format and uses COMTRADE file types to output these data:

➤ .HDR—header file

➤ .CFG—configuration file

➤ .DAT—high-resolution raw data file

The .HDR file contains summary information about the event in ASCII format. The .CFG file is an ASCII configuration file that describes the layout of the .DAT file. The .DAT file is in binary format and contains the values for each input channel for each sample in the record. These data conform to the IEEE C37.111-1999 COMTRADE standard.

.HDR File

The .HDR file contains the summary and relay settings (comma-delimited) information that appears in the event report for the data capture (see *HIF Event Summary on page 12.48*). *Figure 12.5* shows a sample COMTRADE .HDR file.

```
FEEDER 1                    Date: 08/06/2012  Time: 17:14:40.056
STATION A                   Time Source: external          Summary Event
                                                           Information
Event: CA T   Location: 7.28    Shot: 0  Frequency: 60.01
Targets: 10 110001001011 110001001011
Currents (A Pri), ABCGQ: 472   472   472    2    3

[1]
RID,"FEEDER 1"
TID,"STATION A"
CTR,"1000.0"                                               Relay Settings
CTRN,"1000.0"
PTRY,"120.00"
PTRZ,"120.00"
.
.
.
SAM/CYC_A = 128                                            Analog, Digital, and Input
SAM/CYC_D = 4                                              samples per cycle data
SAM/CYC_INPUTS = 16
```

Figure 12.5   Sample COMTRADE .HDR Header File

.CFG File

The .CFG file contains data that are used to reconstruct the input signals to the relay and status of Relay Word bits during the event report (see *Figure 12.6*). A <CR><LF> follows each line. If control inputs or control outputs are not available because of board loading and configuration, the relay does not report these inputs and outputs in the analog and digital sections of the .CFG file.

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```
<RID setting>,FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx,1999 ———————  COMTRADE Standard
#T, #A, #D ————————————————————————————————————————————  Total Channels, Analog, Digital
1,IA,A,,A,scale_factor¹,0,0,-32767,32767,[CTR],1,P
2,IB,B,,A,scale_factor¹,0,0,-32767,32767,[CTR],1,P
3,IC,C,,A,scale_factor¹,0,0,-32767,32767,[CTR],1,P
4,IN,,,A,scale_factor¹,0,0,-32767,32767,[CTRN],1,P
5,3IO,,,A,scale_factor¹,0,0,-32767,32767,[CTR],1,P
6,VAY,A,,kV,scale_factor¹,0,0,-32767,32767,[PTRY],1,P
7,VBY,B,,kV,scale_factor¹,0,0,-32767,32767,[PTRY],1,P     Analog Channel Data
8,VCY,C,,kV,scale_factor¹,0,0,-32767,32767,[PTRY],1,P
9,VAZ,A,,kV,scale_factor¹,0,0,-32767,32767,[PTRZ],1,P
10,VBZ,B,,kV,scale_factor¹,0,0,-32767,32767,[PTRZ],1,P
11,VCZ,C,,kV,scale_factor¹,0,0,-32767,32767,[PTRZ],1,P
12,FREQ,,,Hz,0.01,0,0,0,0,12000,1,1,P
1,rwb_label²,³,,,O
2,rwb_label²,³,,,O
.
.
.
nnnn⁴,rwb_label²,³,,,O                                   Digital (Status)
<NFREQ>                                                  Channel Data
O
0,<# of samples>
dd/mm/yyyy,hh:mm:ss.ssssss  ——————————————————————————————  First Data Point
dd/mm/yyyy,hh:mm:ss.ssssss  ——————————————————————————————  Trigger Point
BINARY
 <time stamp multiplication factor>
```

[1] scale_factor is the value used to convert the equivalent channel analog data in the DAT file to primary units (A or kV peak-to-peak).

[2] rwb_label will be replaced with Relay Word bit labels as seen in Table F.1.

[3] Place holders denoted by asterisk (*), will be labeled as UNUSEDxxx (where xxx is the number of the associated label).

[4] nnnn = number of the last Relay Word bit.

Figure 12.6   Sample COMTRADE .CFG Configuration File Data

The configuration file has the following format:

➤ Station name, device identification, COMTRADE standard year

➤ Number and type of channels

➤ Channel name units and conversion factors

➤ Digital relay word bit names

➤ System frequency

➤ Sample rate and number of samples

➤ Date and time of first data point

➤ Date and time of trigger point

➤ Data file type

➤ Time stamp multiplication factor

.DAT File

The .DAT file follows the COMTRADE binary standard. The format of the binary data files is sample number, time stamp, data value for each analog channel, and digital channel status data for each sample in the file. There are no data separators or carriage return/line feed characters in the binary file. The sequential position of the data in the binary file determines the data translation. Refer to the *IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems, IEEE C37.111–1999* for more information. Many programs read the binary COMTRADE files. These programs include Analytic Assistant and QuickSet.

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Retrieving COMTRADE Event Files

COMTRADE files are available as read-only files that can be retrieved using the **FILE** command and Ymodem file transfer, Ethernet File Transfer Protocol (FTP), or Manufacturing Messaging Specification (MMS). MMS is only available in models that support IEC 61850 and only when IEC 61850 is enabled (E61850 = Y). See *FIL Command on page 10.49*, *File Transfer Protocol (FTP) and MMS File Transfer on page 10.17*, and *MMS on page L.4* for additional information. You can also use QuickSet (see *QuickSet Event Analysis on page 3.18*).

ASCII Event Reports

The latest event reports are stored in nonvolatile memory. Each event report includes five sections:

➤ Analog values of current, voltage, and frequency, and digital states of the various trip, close, 52A_, and ground switch Relay Word bits (**EVE** command option A).

➤ Digital states of the Protection and Control elements, including overcurrent, voltage, synchronism check, and frequency elements, plus reclosing recloser control status and digital output and input states (**EVE** command option D).

➤ Digital states of the MIRRORED BITS, Communications, and Automation Elements, including power elements, and operator control pushbutton status (**EVE** command option M).

➤ Event Summary.

➤ Recloser Control Settings in service at the time of event trigger, consisting of Group, Logic, Global, and Report settings classes.

NOTE: Use the **HIS** command to obtain a brief listing of all of the event reports in nonvolatile memory, including the event number "n" (see HIS Command (Event Summaries/History) on page 10.54).

Use the **EVE** command to retrieve the reports. There are several options to customize the report format. The general command format is:

EVE [*n* S*x* L*y* L R P A D V C M]

where:

    n Event number (1–number of events stored) or unique event identifier (10000–65535). Defaults to 1 if not listed, where 1 is the most recent event.

    S*x* Display *x* samples per cycle (4, 16, 32, or 128), defaults to 4 if not listed. If S*x* parameter is present, it overrides the L parameter. S128 is available as unfiltered (raw) data only and thus must be accompanied by the R parameter (EVE S128 R).

    L*y* Display *y* cycles of data (1–LER). Defaults to LER value if not listed. Unfiltered reports (R parameter) display one extra cycle of data, and S128 unfiltered reports display two extra cycles of data.

    L Display 32 samples per cycle; same as the S32 parameter.

    R Specifies the unfiltered (raw) event report. Defaults to 32 samples per cycle unless overridden with the S*x* parameter.

    A Specifies that only the analog section of the event is displayed.

    D Specifies that only the digital section (Protection and Control Elements) of the event is displayed.

    V Specifies variable scaling for analog values.

    C Display the report in Compressed ASCII format. Defaults to 1/16-cycle analog and 1/4-cycle digital resolution.

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where:

M	Specifies only the MIRRORED BITS, Communication, and Automation Elements section of the event is displayed.
P	Precise to synchrophasor level accuracy for signal content at nominal frequency. This option is available only for events triggered when TSOK = logical 1. The P option implies R as only raw analog data are available with this accuracy. When M or D are specified with P, then the P option is ignored because it only pertains to analog data.

Below are **EVE** command examples:

NOTE: SEL-651R-2 ASCII event reports (**EVE** command) will not display properly in Analytic Assistant. When retrieving events for use with PC software, use the Compressed ASCII **CEV** command.

NOTE: **EVE** options have no specific order (e.g., **EVE 2 D** functions the same as **EVE D 2**).

Serial Port Command	Description
EVE	Display the most recent event report at 1/4-cycle resolution (analog and digital).
EVE 2	Display the second event report at 1/4-cycle resolution.
EVE S32 L10	Display 10 cycles of the most recent report at 1/32-cycle resolution.
EVE C 2	Display the second report in Compressed ASCII format at 1/16-cycle resolution.
EVE L	Display most recent report at 1/32-cycle resolution.
EVE S128 R	Display most recent report at 1/128-cycle resolution; analog data are unfiltered (raw).
EVE 2 D L10	Display 10 cycles of the protection and control elements section of the second event report at 1/4-cycle resolution.
EVE 2 A R S4 V	Display the unfiltered analog section of the second event report at 1/4-cycle resolution, with variable scaling of the analog values.

If an event report is requested that does not exist, the recloser control responds:

```
Invalid Event
```

Standard EVE Report Column Definitions

Refer to the example event report in *Figure 12.8* to view event report columns. This example event report displays rows of information each 1/4 cycle and was retrieved with the **EVE** command.

NOTE: Figure 12.8 is on multiple pages.

The columns contain ac current, ac voltage, frequency, output, input, and protection and control element information.

Current, Voltage, and Frequency Columns. *Table 12.4* summarizes the event report current, voltage, and frequency columns.

Table 12.4 Standard Event Report Current, Voltage, and Frequency Columns (Sheet 1 of 2)

Column Heading	Definition
IA	Current measured by channel IA[a] (primary A)
IB	Current measured by channel IB[a] (primary A)
IC	Current measured by channel IC[a] (primary A)

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Table 12.4   Standard Event Report Current, Voltage, and Frequency Columns (Sheet 2 of 2)

Column Heading	Definition
IG	Ground current IG = 3I0; calculated from channels IA, IB, and IC when Relay Word bit GNDSW = logical 0; or IG = channel IN; when GNDSW = logical 1 (primary A)
VAY	Voltage measured on Y-terminal, A-phase[b] (primary kV)
VBY	Voltage measured on Y-terminal, B-phase[b] (primary kV)
VCY	Voltage measured on Y-terminal, C-phase[b] (primary kV)
VAZ	Voltage measured on Z-terminal, A-phase[b] (primary kV)
VBZ	Voltage measured on Z-terminal, B-phase[b] (primary kV)
VCZ	Voltage measured on Z-terminal, C-phase[b] (primary kV)
Freq[c]	Frequency measured on VY terminals when FSELECT := VY or OFF, VZ terminals when FSELECT := VZ
DT[d]	Difference time referenced to previous row (microseconds)

[a] Global setting IPCONN determines the current phase assignment (see Table 9.8).
[b] Global settings VYCONN or VZCONN determine the voltage phase assignment (see Table 9.9).
[c] Not available with P parameter.
[d] Only available with P parameter (see Synchrophasor-Level Accuracy in Event Reports on page 12.31).

Note that the ac values change from plus to minus (–) values in *Figure 12.8*, indicating the sinusoidal nature of the waveforms.

Other figures help in understanding the information available in the event report current columns:

Figure 12.9 shows how event report current column data relate to the actual sampled current waveform and rms current values.

Figure 12.10 shows how event report current column data can be converted to phasor rms current values.

Variable Scaling for Analog Values.   The following example shows the difference between two cycles of the analog values of an event report without variable scaling (command **EVE**) and with variable scaling (command **EVE V**). Variable scaling event reports display data for currents less than 10 A with two decimal places and data for voltages less than 10 kV with three decimal places.

Example without variable scaling (**EVE**):

```
 =>EVE <Enter>
 ⋮
                                                                5G
    Currents (Amps Pri)              Voltages (kV Pri)         TC2N
    IA     IB     IC    IG    VAY    VBY    VCY    VAZ    VBZ    VCZ Freq RLAD
 [1]
    185   -306    122   -0   11.2  -13.4    2.2   11.2  -13.4    2.2 60.02 ..*N
    247    36    -284    0    9.0    5.2  -14.2    9.0    5.2  -14.2 60.02 ..*N
   -185    306   -122    0  -11.2   13.4   -2.2  -11.2   13.4   -2.2 60.02 ..*N
   -247   -36    283     0   -9.0   -5.2   14.2   -9.0   -5.2   14.2 60.02 ..*N
 [2]
    185   -306    122   -0   11.2  -13.4    2.2   11.2  -13.4    2.2 60.02 ..*N
    247    36    -284   -0    9.0    5.2  -14.2    9.0    5.2  -14.2 60.02 ..*N
   -185    306   -122    0  -11.2   13.4   -2.2  -11.2   13.4   -2.2 60.02 ..*N
   -247   -36    284     0   -9.0   -5.2   14.2   -9.0   -5.2   14.2 60.02 ..*N
 ⋮
```

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Example with variable scaling (**EVE V**):

```
=>EVE V <Enter>
:
                                                                    5G
                                                                  TC2N
     Currents (Amps Pri)              Voltages (kV Pri)         Freq RLAD
     IA    IB    IC    IG    VAY    VBY    VCY    VAZ    VBZ    VCZ
[1]
    185  -306   122  -0.02   11.2  -13.4   2.154   11.2  -13.4   2.155 60.02 ..*N
    247    36  -284   0.01  8.968   5.230 -14.2   8.968   5.231 -14.2 60.02 ..*N
   -185   306  -122   0.04  -11.2   13.4  -2.155  -11.2   13.4  -2.155 60.02 ..*N
   -247   -36   283   0.06 -8.970  -5.232  14.2  -8.969  -5.233  14.2 60.02 ..*N
[2]
    185  -306   122  -0.07   11.2  -13.4   2.153   11.2  -13.4   2.153 60.02 ..*N
    247    36  -284  -0.06  8.968   5.232 -14.2   8.968   5.233 -14.2 60.02 ..*N
   -185   306  -122   0.05  -11.2   13.4  -2.154  -11.2   13.4  -2.154 60.02 ..*N
   -247   -36   284   0.01 -8.966  -5.236  14.2  -8.966  -5.237  14.2 60.02 ..*N
:
```

Output, Input, and Protection, and Control Columns.

Table 12.5 summarizes the event report output, input, protection and control columns. See *Table F.1* and *Table F.2* for more information on Relay Word bits shown in *Table 12.5*.

Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 1 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
All columns		•	Element/input/output not picked up or not asserted, unless otherwise stated
TR	TRIP3P	*	Trip (TRIP3P asserted)
	TRIPA	A	A-phase trip (TRIPA asserted)
	TRIPB	B	B-phase trip (TRIPB asserted)
	TRIPC	C	C-phase trip (TRIPC asserted)
		a	A and B-phase trip (TRIPA and TRIPB asserted)
		b	B and C-phase trip (TRIPB and TRIPC asserted)
		c	C and A-phase trip (TRIPC and TRIPA asserted)
		3	Three-phase trip (TRIPA, TRIPB, and TRIPC asserted)
CL	CLOSE3P	*	Close (CLOSE3P asserted)
	CLOSEA	A	A-phase close (CLOSEA asserted)
	CLOSEB	B	B-phase close (CLOSEB asserted)
	CLOSEC	C	C-phase close (CLOSEC asserted)
		a	A and B-phase close (CLOSEA and CLOSEB asserted)
		b	B and C-phase close (CLOSEB and CLOSEC asserted)
		c	C and A-phase close (CLOSEC and CLOSEA asserted)
		3	Three-phase close (CLOSEA, CLOSEB, and CLOSEC asserted)

NOTE: TRIP3P is only available when Group setting ESPB := N.

NOTE: TRIPA, TRIPB, and TRIPC are only available when Group setting ESPB := Y.

NOTE: CLOSE3P is only available when Group setting ESPB := N.

NOTE: CLOSEA, CLOSEB, and CLOSEC are only available when Group setting ESPB := Y.

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 2 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
52A	52A3P	*	Breaker closed (52A3P asserted)
	52AA	A	A-phase breaker closed (52AA asserted)
	52AB	B	B-phase breaker closed (52AB asserted)
	52AC	C	C-phase breaker closed (52AC asserted)
		a	A and B-phase breakers closed (52AA and 52AB asserted)
		b	B and C-phase breakers closed (52AB and 52AC asserted)
		c	C and A-phase breakers closed (52AC and 52AA asserted)
		3	3 breakers closed (52AA, 52AB, and 52AC asserted)
GND	GNDSW	G	IG = 3I0 calculated (GNDSW deasserted)
		N	IG = IN measured (GNDSW asserted)
51A	51A, 51AT, 51AR, 51AS	.	51p element is reset
51B	51B, 51BT, 51BR, 51BS	R	51p J-element timing to reset
		P	51p J-element picked up and timing
51C	51C, 51CT, 51CR, 51CS	T	51p J-element timed out
51P	51P, 51PT, 51PR, 51PS	r	51p K-element timing to reset
51G1	51G1, 51G1T, 51G1R, 51G1S	p	51p K-element picked up and timing
51G2	51G2, 51G2T, 51G2R, 51G2S	t	51p K-element timed out
51Q	51Q, 51QT, 51QR, 51QS	1	51p element is performing a one-cycle reset (only when 51pRS := N)
50 ABC	50A, 50B, 50C	A	Single-phase instantaneous overcurrent element 50A picked up
		B	Single-phase instantaneous overcurrent element 50B picked up
		C	Single-phase instantaneous overcurrent element 50C picked up
		a	Both 50A and 50B picked up
		b	Both 50B and 50C picked up
		c	Both 50C and 50A picked up
		3	50A, 50B, and 50C picked up

NOTE: 52AA, 52AB, and 52AC are only available when Global setting BKTYP := 1.

NOTE: p = A, B, C, P, G1, G2, or Q.

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 3 of 14)

NOTE: p = P, N, G, or Q.

NOTE: 50N_ elements are only enabled when Global setting EGNDSW := N.

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
50 P	50P1, 50P2, 50P3, 50P4	4	Instantaneous o/c element 50p4 picked up; levels 1, 2, and 3 not picked up
50 N	50N1, 50N2, 50N3, 50N4	3	Instantaneous o/c element 50p3 picked up; levels 1 and 2 not picked up
50 G	50G1, 50G2, 50G3, 50G4		Instantaneous o/c element 50p2 picked up; level 1 not picked up
50 Q	50Q1, 50Q2, 50Q3, 50Q4	2	Instantaneous o/c element 50p1 picked up
		1	
32 PQ	F32P	P	Forward positive-sequence voltage-polarized directional element F32P picked up
	R32P	p	Reverse positive-sequence voltage-polarized directional element R32P picked up
	F32Q	Q	Forward negative-sequence voltage-polarized directional element F32Q picked up
	R32Q	q	Reverse negative-sequence voltage-polarized directional element R32Q picked up
32 G	F32QG	Q	Forward negative-sequence voltage-polarized directional element F32QG picked up
	R32QG	q	Reverse negative-sequence voltage-polarized directional element R32QG picked up
	F32V	V	Forward zero-sequence voltage-polarized directional element F32V picked up
	R32V	v	Reverse zero-sequence voltage-polarized directional element R32V picked up
Dm PQ	PDEM, QDEM	P	Phase demand ammeter element PDEM picked up
		Q	Negative-sequence demand ammeter element QDEM picked up
		b	Both PDEM and QDEM picked up
Dm NG	NDEM, GDEM	N	Neutral ground demand ammeter element NDEM picked up
		G	Residual ground demand ammeter element GDEM picked up
		b	Both NDEM and GDEM picked up
27 Y P	27YA1, 27YA2, 27YB1, 27YB2, 27YC1, 27YC2	A	A-phase instantaneous undervoltage element 27YA1 or 27YA2 picked up
		B	B-phase instantaneous undervoltage element 27YB1 or 27YB2 picked up

NOTE: NDEM element is only enabled when Global setting EGNDSW := N.

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 4 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
		C	C-phase instantaneous undervoltage element 27YC1 or 27YC2 picked up
		a	27YA_ and 27YB_ elements picked up
		b	27YB_ and 27YC_ elements picked up
		c	27YC_ and 27YA_ elements picked up
		3	27YA_, 27YB_ , and 27YC_ elements picked up
27 Y PP	27YAB1, 27YBC1, 27YCA1	A	AB phase-to-phase instantaneous undervoltage element 27YAB1 picked up
		B	BC phase-to-phase instantaneous undervoltage element 27YBC1 picked up
		C	CA phase-to-phase instantaneous undervoltage element 27YCA1 picked up
		a	27YAB1 and 27YCA1 elements picked up
		b	27YAB1 and 27YBC1 elements picked up
		c	27YBC1 and 27YCA1 elements picked up
		3	27YAB1, 27YBC1, and 27YCA1 elements picked up
59 Y P	59YA1, 59YA2, 59YB1, 59YB2, 59YC1, 59YC2	A	A-phase instantaneous overvoltage element 59YA1 or 59YA2 picked up
		B	B-phase instantaneous overvoltage element 59YB1 or 59YB2 picked up
		C	C-phase instantaneous overvoltage element 59YC1 or 59YC2 picked up
		a	59YA_ and 59YB_ elements picked up
		b	59YB_ and 59YC_ elements picked up
		c	59YC_ and 59YA_ elements picked up
		3	59YA_, 59YB_, and 59YC_ elements picked up
59 Y PP	59YAB1, 59YBC1, 59YCA1	A	AB phase-to-phase instantaneous overvoltage element 59YAB1 picked up
		B	BC phase-to-phase instantaneous overvoltage element 59YBC1 picked up
		C	CA phase-to-phase instantaneous overvoltage element 59YCA1 picked up
		a	59YAB1 and 59YCA1 elements picked up
		b	59YAB1 and 59YBC1 elements picked up
		c	59YBC1 and 59YCA1 elements picked up
		3	59YAB1, 59YBC1, and 59YCA1 elements picked up

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Table 12.5 Output, Input, and Protection, and Control Element Event Report Columns (Sheet 5 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
59 Y V1	59YV1	*	Positive-sequence instantaneous over-voltage element 59YV1 picked up
59 Y N	59YN1, 59YN2	1	Zero-sequence instantaneous overvolt-age element 59YN1 picked up
		2	Zero-sequence instantaneous overvolt-age element 59YN2 picked up
		b	Both 59YN1 and 59YN2 picked up
59 Y Q	59YQ1	*	Negative-sequence instantaneous over-voltage element 59YQ1 picked up
27 Z P	27ZA1, 27ZA2, 27ZB1, 27ZB2, 27ZC1, 27ZC2	A	A-phase instantaneous undervoltage element 27ZA1 or 27ZA2 picked up
		B	B-phase instantaneous undervoltage element 27ZB1 or 27ZB2 picked up
		C	C-phase instantaneous undervoltage element 27ZC1 or 27ZC2 picked up
		a	27ZA_ and 27ZB_ elements picked up
		b	27ZB_ and 27ZC_ elements picked up
		c	27ZC_ and 27ZA_ elements picked up
		3	27ZA_, 27ZB_ , and 27ZC_ elements picked up
27 Z PP	27ZAB1, 27ZBC1, 27ZCA1	A	AB phase-to-phase instantaneous under-voltage element 27ZAB1 picked up
		B	BC phase-to-phase instantaneous under-voltage element 27ZBC1 picked up
		C	CA phase-to-phase instantaneous under-voltage element 27ZCA1 picked up
		a	27ZAB1 and 27ZCA1 elements picked up
		b	27ZAB1 and 27ZBC1 elements picked up
		c	27ZBC1 and 27ZCA1 elements picked up
		3	27ZAB1, 27ZBC1, and 27ZCA1 ele-ments picked up
59 Z P	59ZA1, 59ZA2, 59ZB1, 59ZB2, 59ZC1, 59ZC2	A	A-phase instantaneous overvoltage element 59ZA1 or 59ZA2 picked up
		B	B-phase instantaneous overvoltage element 59ZB1 or 59ZB2 picked up
		C	C-phase instantaneous overvoltage element 59ZC1 or 59ZC2 picked up
		a	59ZA_ and 59ZB_ elements picked up
		b	59ZB_ and 59ZC_ elements picked up
		c	59ZC_ and 59ZA_ elements picked up.
		3	59ZA_, 59ZB_, and 59ZC_ elements picked up

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 6 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
59 Z PP	59ZAB1, 59ZBC1, 59ZCA1	A	AB phase-to-phase instantaneous over-voltage element 59ZAB1 picked up
		B	BC phase-to-phase instantaneous over-voltage element 59ZBC1 picked up
		C	CA phase-to-phase instantaneous over-voltage element 59ZCA1 picked up
		a	59ZAB1 and 59ZCA1 elements picked up
		b	59ZAB1 and 59ZBC1 elements picked up
		c	59ZBC1 and 59ZCA1 elements picked up
		3	59ZAB1, 59ZBC1, and 59ZCA1 elements picked up
59 Z V1	59ZV1	*	Positive-sequence instantaneous over-voltage element 59ZV1 picked up
59 Z N	59ZN1, 59ZN2	1	Zero-sequence instantaneous overvoltage element 59ZN1 picked up
		2	Zero-sequence instantaneous overvoltage element 59ZN2 picked up
		b	Both 59ZN1 and 59ZN2 picked up
59 Z Q	59ZQ1	*	Negative-sequence instantaneous over-voltage element 59ZQ1 picked up
59 V	59VP, 59VS	P	Phase voltage window element 59VP picked up (used in synchronism check)
		S	Channel VS voltage window element 59VS picked up (used in synchronism check)
		b	Both 59VP and 59VS picked up
25 SF	SF	*	Slip frequency element SF picked up (used in synchronism check)
25 A	25A1, 25A2	1	Synchronism-check element 25A1 element picked up
		2	Synchronism-check element 25A2 element picked up
		b	Both 25A1 and 25A2 picked up
27B	27B81	*	Frequency logic instantaneous under-voltage element 27B81 picked up
81 12	81D1, 81D2	1	Frequency element 81D1 picked up
		2	Frequency element 81D2 picked up
		b	Both 81D1 and 81D2 picked up
81 34	81D3, 81D4	3	Frequency element 81D3 picked up
		4	Frequency element 81D4 picked up
		b	Both 81D3 and 81D4 picked up
81 56	81D5, 81D6	5	Frequency element 81D5 picked up
		6	Frequency element 81D6 picked up
		b	Both 81D5 and 81D6 picked up

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 7 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
79	RCSF3P, CF3P 79RS3P, 79CY3P, 79LO3P RCSFA, CFA, 79RSA, 79CYA, 79LOA	•	Reclosing relay nonexistent
		S	Reclose supervision failure condition (RCSF_ asserts for only 1/4 cycle)
		F	Close failure condition (CF_ asserts for only 1/4 cycle)
		R	Reclosing relay in Reset State (79RS_)
		C	Reclosing relay in Reclose Cycle State (79CY_)
		L	Reclosing relay in Lockout State (79LO_)
Time	OPTMN3P, RSTMN3P OPTMNA, RSTMNA	o	Recloser open interval timer is timing
		r	Recloser reset interval timer is timing
Shot	SH03P, SH13P, SH23P, SH33P, SH43P SH0A, SH1A, SH2A, SH3A, SH4A	.	Reclosing relay nonexistent
		0	shot = 0 (SH0_)
		1	shot = 1 (SH1_)
		2	shot = 2 (SH2_)
		3	shot = 3 (SH3_)
		4	shot = 4 (SH4_)
B79	RCSFB, CFB, 79RSB, 79CYB, 79LOB	.	Reclosing relay nonexistent
		S	Reclose supervision failure condition (RCSFB asserts for only 1/4 cycle)
		F	Close failure condition (CFB asserts for only 1/4 cycle)
		R	Reclosing relay in Reset State (79RSB)
		C	Reclosing relay in Reclose Cycle State (79CYB)
		L	Reclosing relay in Lockout State (79LOB)
B Time	OPTMNB, RSTMNB	o	Recloser open interval timer is timing
		r	Recloser reset interval timer is timing
B Shot	SH0B, SH1B, SH2B, SH3B, SH4B	.	Reclosing relay nonexistent
		0	shot = 0 (SH0B)
		1	shot = 1 (SH1B)
		2	shot = 2 (SH2B)
		3	shot = 3 (SH3B)
		4	shot = 4 (SH4B)

NOTE: Relay Word bits RCSF3P, CF3P, 79RS3P, 79CY3P, and 79LO3P are used when Group setting ESPB := N.

NOTE: Relay Word bits RCSFA, CFA, 79RSA, 79CYA, and 79LOA are used when Group setting ESPB := Y.

NOTE: Relay Word bits OPTMN3P, RSTMN3P, SH03P, SH13P, SH23P, SH33P, and SH43P are used when Group setting ESPB := N.

NOTE: Relay Word bits OPTMNA, RSTMNA, SH0A, SH1A, SH2A, SH3A, and SH4A are used when Group setting ESPB := Y.

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 8 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
C79	RCSFC, CFC, 79RSC, 79CYC, 79LOC	.	Reclosing relay nonexistent
		S	Reclose supervision failure condition (RCSFC asserts for only 1/4 cycle)
		F	Close failure condition (CFC asserts for only 1/4 cycle)
		R	Reclosing relay in Reset State (79RSC)
		C	Reclosing relay in Reclose Cycle State (79CYC)
		L	Reclosing relay in Lockout State (79LOC)
C Time	OPTMNC, RSTMNC	o	Recloser open interval timer is timing
		r	Recloser reset interval timer is timing
C Shot	SH0C, SH1C, SH2C, SH3C, SH4C	.	Reclosing relay nonexistent
		0	shot = 0 (SH0C)
		1	shot = 1 (SH1C)
		2	shot = 2 (SH2C)
		3	shot = 3 (SH3C)
		4	shot = 4 (SH4C)
Zld	ZLIN, ZLOUT	i	Load encroachment "load in" element ZLIN picked up
		o	Load encroachment "load out" element ZLOUT picked up
LOP	LOP	*	Loss-of-potential element LOP picked up
PS	PWR_SRC1	1	SEL-651R-2 power supply input energized
TCAP	TCCAP	*	Trip and close capacitor voltage above minimum acceptable value
200 (Out) 12	OUT201, OUT202	1	Output contact OUT201 asserted
		2	Output contact OUT202 asserted
		b	Both OUT201 and OUT202 asserted
200 In 12	IN201, IN202	1	Status Input IN201 asserted
		2	Status Input IN202 asserted
		b	Both IN201 and IN202 asserted
200 In 34	IN203, IN204	3	Status Input IN203 asserted
		4	Status Input IN204 asserted
		b	Both IN203 and IN204 asserted
200 In 56	IN205, IN206	5	Status Input IN205 asserted
		6	Status Input IN206 asserted
		b	Both IN205 and IN206 asserted
100 Out 12	OUT101, OUT102	1	Output contact OUT101 asserted
		2	Output contact OUT102 asserted
		b	Both OUT101 and OUT102 asserted

NOTE: Output contacts OUT201 and OUT202 are C-type contacts (see Figure 7.27).

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Table 12.5 Output, Input, and Protection, and Control Element Event Report Columns (Sheet 9 of 14)

NOTE: Event report columns for output contacts OUT101–OUT108 are only shown when the SEL-651R-2 is ordered with the extra inputs and outputs option. OUT101–OUT 105 are A-type contacts, OUT106–OUT108 are C-type contacts (see Section 2: Installation and Figure 7.27).

NOTE: Event report columns for optoisolated inputs IN101–IN107 are only shown when the SEL-651R-2 is ordered with the extra inputs and outputs option.

NOTE: Relay Word bits SPO, SPOA, SPOB, and SPOC only available when Global setting BKTYP := 1.

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
100 Out 34	OUT103, OUT104	3	Output contact OUT103 asserted
		4	Output contact OUT104 asserted
		b	Both OUT103 and OUT104 asserted
100 Out 56	OUT105, OUT106	5	Output contact OUT105 asserted
		6	Output contact OUT106 asserted
		b	Both OUT105 and OUT106 asserted
100 Out 78	OUT107, OUT108	7	Output contact OUT107 asserted.
		8	Output contact OUT108 asserted.
		b	Both OUT107 and OUT108 asserted.
100 In 12	IN101, IN102	1	Optoisolated input IN101 asserted
		2	Optoisolated input IN102 asserted
		b	Both IN101 and IN102 asserted
100 In 34	IN103, IN104	3	Optoisolated input IN103 asserted
		4	Optoisolated input IN104 asserted
		b	Both IN103 and IN104 asserted
100 In 56	IN105, IN106	5	Optoisolated input IN105 asserted
		6	Optoisolated input IN106 asserted
		b	Both IN105 and IN106 asserted
100 In 7	IN107	7	Optoisolated input IN107 asserted
PO	3PO, SPO, SPOA, SPOB, SPOC	3	Three-pole open condition, 3PO asserted
		A	A-phase open (SPOA AND NOT 3PO)
		B	B-phase open (SPOB AND NOT 3PO)
		C	C-phase open (SPOC AND NOT 3PO)
		a	A- and B-phases open (SPOA AND SPOB AND NOT 3PO)
		b	B- and C-phases open (SPOB AND SPOC AND NOT 3PO)
		c	C- and A-phases open (SPOC AND SPOA AND NOT 3PO)
		S	Single pole open delay timer dropping out
SOTF	SOTFE	*	Switch-onto-fault SOTF enable asserted
TMB A 12	TMB1A, TMB2A	1	MIRRORED BITS channel A transmit bit 1 TMB1A asserted
		2	MIRRORED BITS channel A transmit bit 2 TMB2A asserted
		b	Both TMB1A and TMB2A asserted
TMB A 34	TMB3A, TMB4A	3	MIRRORED BITS channel A transmit bit 3 TMB3A asserted
		4	MIRRORED BITS channel A transmit bit 4 TMB4A asserted
		b	Both TMB3A and TMB4A asserted

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Table 12.5 Output, Input, and Protection, and Control Element Event Report Columns (Sheet 10 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
TMB A 56	TMB5A, TMB6A	5	MIRRORED BITS channel A transmit bit 5 TMB5A asserted
		6	MIRRORED BITS channel A transmit bit 6 TMB6A asserted
		b	Both TMB5A and TMB6A asserted
TMB A 78	TMB7A, TMB8A	7	MIRRORED BITS channel A transmit bit 7 TMB7A asserted
		8	MIRRORED BITS channel A transmit bit 8 TMB8A asserted
		b	Both TMB7A and TMB8A asserted
RMB A 12	RMB1A, RMB2A	1	MIRRORED BITS channel A receive bit 1 RMB1A asserted
		2	MIRRORED BITS channel A receive bit 2 RMB2A asserted
		b	Both RMB1A and RMB2A asserted
RMB A 34	RMB3A, RMB4A	3	MIRRORED BITS channel A receive bit 3 RMB3A asserted
		4	MIRRORED BITS channel A receive bit 4 RMB4A asserted
		b	Both RMB3A and RMB4A asserted
RMB A 56	RMB5A, RMB6A	5	MIRRORED BITS channel A receive bit 5 RMB5A asserted
		6	MIRRORED BITS channel A receive bit 6 RMB6A asserted
		b	Both RMB5A and RMB6A asserted
RMB A 78	RMB7A, RMB8A	7	MIRRORED BITS channel A receive bit 7 RMB7A asserted
		8	MIRRORED BITS channel A receive bit 8 RMB8A asserted
		b	Both RMB7A and RMB8A asserted
TMB B 12	TMB1B, TMB2B	1	MIRRORED BITS channel B transmit bit 1 TMB1B asserted
		2	MIRRORED BITS channel B transmit bit 2 MB2B asserted
		b	Both TMB1B and TMB2B asserted
TMB B 34	TMB3B, TMB4B	3	MIRRORED BITS channel B transmit bit 3 TMB3B asserted
		4	MIRRORED BITS channel B transmit bit 4 TMB4B asserted
		b	Both TMB3B and TMB4B asserted
TMB B 56	TMB5B, TMB6B	5	MIRRORED BITS channel B transmit bit 5 TMB5B asserted
		6	MIRRORED BITS channel B transmit bit 6 TMB6B asserted
		b	Both TMB5B and TMB6B asserted

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Table 12.5 Output, Input, and Protection, and Control Element Event Report Columns (Sheet 11 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
TMB B 78	TMB7B, TMB8B	7	MIRRORED BITS channel B transmit bit 7 TMB7B asserted
		8	MIRRORED BITS channel B transmit bit 8 TMB8B asserted
		b	Both TMB7B and TMB8B asserted
RMB B 12	RMB1B, RMB2B	1	MIRRORED BITS channel B receive bit 1 RMB1B asserted
		2	MIRRORED BITS channel B receive bit 2 RMB2B asserted
		b	Both RMB1B and RMB2B asserted.
RMB B 34	RMB3B, RMB4B	3	MIRRORED BITS channel B receive bit 3 RMB3B asserted
		4	MIRRORED BITS channel B receive bit 4 RMB4B asserted
		b	Both RMB3B and RMB4B asserted
RMB B 56	RMB5B, RMB6B	5	MIRRORED BITS channel B receive bit 5 RMB5B asserted
		6	MIRRORED BITS channel B receive bit 6 RMB6B asserted
		b	Both RMB5B and RMB6B asserted
RMB B 78	RMB7B, RMB8B	7	MIRRORED BITS channel B receive bit 7 RMB7B asserted
		8	MIRRORED BITS channel B receive bit 8 RMB8B asserted
		b	Both RMB7B and RMB8B asserted
ROK	ROKA, ROKB	A	MIRRORED BITS channel A receive ok ROKA asserted
		B	MIRRORED BITS channel B receive ok ROKB asserted
		b	Both ROKA and ROKB asserted
RBAD	RBADA, RBADB	A	MIRRORED BITS channel A extended outage RBADA asserted
		B	MIRRORED BITS channel B extended outage RBADB asserted
		b	Both RBADA and RBADB asserted
CBAD	CBADA, CBADB	A	MIRRORED BITS channel A unavailability CBADA asserted
		B	MIRRORED BITS channel B unavailability CBADB asserted
		b	Both CBADA and CBADB asserted
LBOK	LBOKA, LBOKB	A	MIRRORED BITS channel A loop back ok LBOKA asserted
		B	MIRRORED BITS channel B loop back ok LBOKB asserted
		b	Both LBOKA and LBOKB asserted

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Table 12.5   Output, Input, and Protection, and Control Element Event Report Columns (Sheet 12 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
Lcl 12	LB01, LB02	1	Local bit LB01 asserted
		2	Local bit LB02 asserted
		b	Both LB01 and LB02 asserted
Lcl 34	LB03, LB04	3	Local bit LB03 asserted
		4	Local bit LB04 asserted
		b	Both LB03 and LB04 asserted
Lcl 56	LB05, LB06	5	Local bit LB05 asserted
		6	Local bit LB06 asserted
		b	Both LB05 and LB06 asserted
Rem 12	RB01, RB02	1	Remote bit RB01 asserted
		2	Remote bit RB02 asserted
		b	Both RB01 and RB02 asserted
Rem 34	RB03, RB04	3	Remote bit RB03 asserted
		4	Remote bit RB04 asserted
		b	Both RB03 and RB04 asserted
Rem 56	RB05, RB06	5	Remote bit RB05 asserted
		6	Remote bit RB06 asserted
		b	Both RB05 and RB06 asserted
Rem 78	RB07, RB08	7	Remote bit RB07 asserted
		8	Remote bit RB08 asserted
		b	Both RB07 and RB08 asserted
Rem OP	OC3	3	OPE command executed
	OCA	A	OPE A command executed
	OCB	B	OPE B command executed
	OCC	C	OPE C command executed
Rem CL	CC3	3	CLO command executed
	CCA	A	CLO A command executed
	CCB	B	CLO B command executed
	CCC	C	CLO C command executed
Ltch 12	LT01, LT02	1	Latch bit LT01 asserted
		2	Latch bit LT02 asserted
		b	Both LT01 and LT02 asserted
Ltch 34	LT03, LT04	3	Latch bit LT03 asserted
		4	Latch bit LT04 asserted
		b	Both LT03 and LT04 asserted
Ltch 56	LT05, LT06	5	Latch bit LT05 asserted
		6	Latch bit LT06 asserted
		b	Both LT05 and LT06 asserted

NOTE: Relay Word bits OC3, OCA, OCB, OCC, CC3, CCA, CCB, and CCC are checked in the order shown. The letter for the first bit found asserted will be displayed.

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Table 12.5 Output, Input, and Protection, and Control Element Event Report Columns (Sheet 13 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
Ltch 78	LT07, LT08	5	Latch bit LT07 asserted
		6	Latch bit LT08 asserted
		b	Both LT07 and LT08 asserted
Ltch 90	LT09, LT10	9	Latch bit LT09 asserted
		0	Latch bit LT10 asserted
		b	Both LT09 and LT10 asserted
Ltch 112	LT11, LT12	1	Latch bit LT11 asserted
		2	Latch bit LT12 asserted
		b	Both LT11 and LT12 asserted
SELOGIC Var01 SELOGIC Var02 SELOGIC Var03 SELOGIC Var04 SELOGIC Var05 SELOGIC Var06 SELOGIC Var07 SELOGIC Var08 SELOGIC Var09 SELOGIC Var10 SELOGIC Var11 SELOGIC Var12 SELOGIC Var13 SELOGIC Var14 SELOGIC Var15 SELOGIC Var16	SV01, SV01T SV02, SV02T SV03, SV03T SV04, SV04T SV05, SV05T SV06, SV06T SV07, SV07T SV08, SV08T SV09, SV09T SV10, SV10T SV11, SV11T SV12, SV12T SV13, SV13T SV14, SV14T SV15, SV15T SV16, SV16T	p T d	SELOGIC control equation variable timer input SVnn asserted; timer timing on pickup time; timer output SVnnT not asserted. SELOGIC control equation variable timer input SVnn asserted; timer timed out on pickup time; timer output SVnnT asserted. SELOGIC control equation variable timer input SVnn not asserted; timer previously timed out on pickup time; timer output SVnnT remains asserted while timer timing on dropout time.
PWR 3P 12	3PWR1, 3PWR2	1	Level 1 three-phase power element 3PWR1 picked up
		2	Level 2 three-phase power element 3PWR2 picked up
		b	Both 3PWR1 and 3PWR2 picked up
PWR 3P 34	3PWR3, 3PWR4	3	Level 3 three-phase power element 3PWR3 picked up
		4	Level 4 three-phase power element 3PWR4 picked up
		b	Both 3PWR3 and 3PWR4 picked up
PB 19	PB01, PB01_PUL	1	PB01 OR PB01_PUL asserted
	PB02, PB02_PUL	2	PB02 OR PB02_PUL asserted
	PB03, PB03_PUL	3	PB03 OR PB03_PUL asserted
	PB04, PB04_PUL	4	PB04 OR PB04_PUL asserted
	PB05, PB05_PUL	5	PB05 OR PB05_PUL asserted
	PB06, PB06_PUL	6	PB06 OR PB06_PUL asserted
	PB07, PB07_PUL	7	PB07 OR PB07_PUL asserted
	PB08, PB08_PUL	8	PB08 OR PB08_PUL asserted
	PB09, PB09_PUL	9	PB09 OR PB09_PUL asserted

NOTE: nn = 01-16.

NOTE: Relay Word Bits PBnn and PBnn_PUL are checked from top to bottom. The letter for the first bit found asserted will be displayed.

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Table 12.5 Output, Input, and Protection, and Control Element Event Report Columns (Sheet 14 of 14)

Column Heading	Corresponding Elements (Relay Word Bits)	Symbol	Definition
PB 02	PB10, PB10_PUL	0	PB10 OR PB10_PUL asserted
	PB11, PB11_PUL	1	PB11 OR PB11_PUL asserted
	PB12, PB12_PUL	2	PB12 OR PB12_PUL asserted

Compressed ASCII Event Reports, Event Summaries, and History

NOTE: Compressed event reports contain analog data from the IN channel, in addition to the IG quantity. (Regular ASCII event reports do not include a separate IN column.)

The SEL-651R-2 provides Compressed ASCII event reports to facilitate event report storage and display. SEL communications processors, QuickSet, and Analytic Assistant take advantage of the Compressed ASCII format. Use the **CHIS** command to display Compressed ASCII event history information. Use the **CSUM** command to display Compressed ASCII event summary information. Use the **EVE C** command or **CEVENT** command to display Compressed ASCII event reports.

NOTE: Compressed ASCII Event Reports contain all of the Relay Word bits and automatic variable analog scaling and are easily analyzed using no-cost software. Regular, uncompressed event reports only contain a subset of the Relay Word bits, do not have automatic variable scaling, and are not fully supported by software. SEL recommends that you use compressed event reports for all event analysis.

See the Compressed ASCII commands in *Appendix C: Compressed ASCII Commands* for further information. You can also use the **Tools > Events > Get Events** menu in QuickSet to collect events.

Use of Compressed ASCII event reports is the preferred means for retrieving event data because the machine-readable format allows the use of time-saving software. Standard ASCII event reports are best suited for rapid analysis, and for situations where only a portion of the event data is under study.

Synchrophasor-Level Accuracy in Event Reports

The SEL-651R-2 provides the option to display event report data aligned to a high-accuracy time source by adding the P parameter. The header indicates the availability of a high-accuracy time source by displaying the status of Relay Word bit TSOK. The `Time:` value in the header includes three additional digits. These represent 100 μs, 10 μs, and 1 μs. The `Time:` value contains the time stamp of the analog value associated with the trigger point.

Furthermore, the `FREQ` column in the analog section of the report is replaced by a `DT` column. DT means "difference time." It represents the difference time in units of microseconds from another row. The trigger point shall have a DT value of 0000 because the trigger time corresponds to the time displayed in the event report header. The DT value for rows preceding the trigger point is referenced to the following row (so they increment backwards in time). The DT value for rows following the trigger point is referenced to the previous row (so they increment forward in time). If TSOK = logical 0, this event report display option is not available.

Figure 12.7 shows how an event report is modified with the P parameter. Because event report information is stored at a sample rate that depends on the power system frequency, the DT data show a minimally changing number when the power system frequency is stable. If the power system frequency changes during the event reporting window and the relay is connected to a voltage reference, the sample rate may vary during the event report and the DT values may vary accordingly.

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```
=>>EVE P <Enter>

FEEDER 1                          Date: 04/02/2012  Time: 09:08:26.377989
STATION A                         TSOK = 1

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx CID=xxxx

                                                                    5G
    Currents (Amps Pri)               Voltages (kV Pri)            TC2N
    IA     IB     IC    IG    VAY   VBY   VCY   VAZ   VBZ   VCZ   DT RLAD
[0]
     6     -4      2     3   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -3      2     5   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     7     -3      3     6   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     7     -3      3     6   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
.
.
.
[4]
     6     -4      1     3   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -4      1     4   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -4      2     5   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -4      2     3   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -5      1     2   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -4      1     2   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     6     -4      2     4   -0.0   0.0  -0.0  -0.0  -0.0  -0.0   625 ...N
     9   -290    302    22    0.0  -2.4   2.4   0.0   2.6  -2.6   625 ...N
   106   -856    758     8    0.9  -6.4   5.5   1.0   5.5  -6.5   625 ...N
   324  -1002    673    -5    2.5  -7.3   4.7   2.6   4.6  -7.3   625 ...N
   537   -998    450   -11    4.1  -7.2   3.1   4.1   3.0  -7.2   625 ...N
   716   -952    222   -14    5.3  -6.9   1.5   5.4   1.4  -6.9   625 ...N
   854   -860    -10   -16    6.3  -6.2  -0.2   6.3  -0.3  -6.1   625 ...N
   946   -720   -245   -19    7.0  -5.1  -1.9   7.0  -1.9  -5.1   625 ...N
   986   -541   -467   -22    7.2  -3.8  -3.5   7.2  -3.5  -3.7   625 ...N
   968   -332   -663   -27    7.1  -2.2  -4.9   7.0  -4.9  -2.2   625 ...N
   899   -107   -813   -21    6.5  -0.6  -6.0   6.5  -6.0  -0.5   625 ...N
   782    125   -924   -17    5.6   1.1  -6.8   5.6  -6.8   1.2   625 ...N
   620    351   -986   -15    4.4   2.8  -7.2   4.3  -7.2   2.8   625 ...N
   423    557   -994   -14    3.0   4.3  -7.2   2.9  -7.2   4.3   626 ...N
   203    728   -945   -14    1.3   5.5  -6.8   1.3  -6.8   5.5   625 ...N
   -28    862   -846   -12   -0.4   6.5  -6.1  -0.4  -6.0   6.5   625 ...N
  -258    947   -700   -11   -2.0   7.1  -5.0  -2.1  -4.9   7.0   625 ...N
  -474    978   -517   -13   -3.6   7.3  -3.6  -3.7  -3.5   7.2   625 ...N
  -663    957   -304   -10   -5.0   7.1  -2.0  -5.0  -2.0   7.0   625 ...N
  -817    880    -75   -12   -6.0   6.5  -0.4  -6.1  -0.3   6.4   625 ...N
  -924    755    157   -12   -6.8   5.5   1.3  -6.8   1.4   5.5   625 ...N
  -983    588    382   -13   -7.2   4.3   2.9  -7.2   3.0   4.2   625 ...N
  -984    389    583   -12   -7.2   2.8   4.4  -7.2   4.4   2.7   625 ...N
  -931    167    750   -14   -6.8   1.2   5.6  -6.7   5.6   1.1   625 ...N
  -830    -67    878   -19   -6.0  -0.6   6.5  -5.9   6.5  -0.6   625 ...N
  -682   -295    955   -22   -4.9  -2.2   7.1  -4.8   7.1  -2.3  0000>...N
[5]
  -494   -508    980   -22   -3.5  -3.8   7.2  -3.4   7.2  -3.8   625 ...N
  -283   -692    950   -25   -1.9  -5.1   7.0  -1.8   6.9  -5.2   625 ...N
   -55   -840    869   -26   -0.2  -6.2   6.3  -0.2   6.3  -6.2   625 ...N
   178   -941    738   -25    1.5  -6.9   5.4   1.5   5.3  -6.9   625 ...N
.
.
.
=>>
```

Figure 12.7 Example Synchrophasor−Level Precise Event Report 1/32-Cycle Resolution

Example 15-Cycle Event Report

The following example standard 15-cycle event report in *Figure 12.8* also corresponds to the example SER report in *Figure 12.11*. The circled numbers in *Figure 12.8* correspond to the SER row numbers in *Figure 12.11*. The row explanations follow *Figure 12.11*.

In *Figure 12.8*, the arrow (>) in the column following the Freq column identifies the "trigger" row. This is the row that corresponds to the Date and Time values at the top of the event report.

The asterisk (*) in the column following the Freq column identifies the row with the maximum phase current. The maximum phase current is calculated from the row identified with the asterisk and the row one quarter-cycle previous (see *Figure 12.9* and *Figure 12.10*). These currents are listed at the end of the event report in the

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event summary. If the trigger row (>) and the maximum phase current row (*) are the same row, the * symbol takes precedence.

```
=>EVE 1 <Enter>

FEEDER 1                      Date: 03/20/2012  Time: 15:21:36.005
STATION A                     Time Source: internal                        ──── firmware identifier

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx        CID=xxxx  ◄────────────── firmware checksum identifier
Event Number=10009
                                                                  5G
                                                                  TC2N
    Currents (Amps Pri)              Voltages (kV Pri)
     IA     IB     IC     IG    VAY    VBY    VCY    VAZ    VBZ    VCZ Freq RLAD
[1]
     185   -306    122     -0   11.2  -13.4    2.2   11.2  -13.4    2.2 60.02 ..*N ┐
     247     36   -284      0    9.0    5.2  -14.2    9.0    5.2  -14.2 60.02 ..*N │
    -185    306   -122      0  -11.2   13.4   -2.2  -11.2   13.4   -2.2 60.02 ..*N ├─ one cycle of data
    -247    -36    283      0   -9.0   -5.2   14.2   -9.0   -5.2   14.2 60.02 ..*N ┘
[2]
     185   -306    122     -0   11.2  -13.4    2.2   11.2  -13.4    2.2 60.02 ..*N
     247     36   -284     -0    9.0    5.2  -14.2    9.0    5.2  -14.2 60.02 ..*N
    -185    306   -122      0  -11.2   13.4   -2.2  -11.2   13.4   -2.2 60.02 ..*N
    -247    -36    284      0   -9.0   -5.2   14.2   -9.0   -5.2   14.2 60.02 ..*N
[3]
     184   -307    122     -0   11.2  -13.4    2.2   11.2  -13.4    2.2 60.02 ..*N
     247     37   -284     -0    9.0    5.2  -14.2    9.0    5.2  -14.2 60.02 ..*N
    -185    306   -122      0  -11.2   13.4   -2.2  -11.2   13.4   -2.2 60.02 ..*N
    -247    -37    284      0   -9.0   -5.2   14.2   -9.0   -5.2   14.2 60.02 ..*N
[4]
     185   -306    122     -0   11.2  -13.4    2.2   11.2  -13.4    2.2 60.02 ..*N
     247     37   -283      0    9.0    5.2  -14.2    9.0    5.2  -14.2 60.02 ..*N
    -215    472   -151    156  -11.4   13.0   -2.3  -11.4   13.0   -2.3 60.02 ..*N
    -254    867    274    884   -8.9   -5.1   14.3   -8.9   -5.1   14.3 60.02>..*N
[5]
     280  -1492    217  -1060   11.6  -12.3    2.5   11.6  -12.3    2.5 60.02 ..*N
     254  -2077   -272  -2093    8.7    4.7  -14.5    8.7    4.7  -14.5 60.02 ..*N
    -316   2304   -254   1808  -11.7   12.1   -2.6  -11.7   12.1   -2.6 60.02 ..*N
    -246   2388    279   2418   -8.6   -4.5   14.5   -8.6   -4.5   14.5 60.02 ..*N
[6]                                                                                        ⑧
     316  -2305    254  -1808   11.7  -12.1    2.6   11.7  -12.1    2.6 60.02 ..*N ◄──────┐
     246  -2389   -279  -2418    8.6    4.5  -14.5    8.6    4.5  -14.5 60.02*.*N
    -315   2304   -254   1808  -11.7   12.1   -2.6  -11.7   12.1   -2.6 60.02 *.*N
    -246   2388    279   2418   -8.6   -4.5   14.5   -8.6   -4.5   14.5 60.02 *.*N
[7]
     315  -2304    254  -1808   11.7  -12.1    2.6   11.7  -12.1    2.6 60.02 *.*N
     246  -2389   -279  -2419    8.6    4.5  -14.5    8.6    4.5  -14.5 60.02 *.*N   See Figure 12.9 and
    -316   2303   -253   1807  -11.7   12.1   -2.6  -11.7   12.1   -2.6 60.02 *.*N   Figure 12.10
    -246   2388    278   2419   -8.6   -4.5   14.5   -8.6   -4.5   14.5 60.02 *.*N
[8]
     315  -2304    253  -1807   11.7  -12.1    2.6   11.7  -12.1    2.6 60.04 *.*N
     246  -2389   -278  -2419    8.6    4.5  -14.5    8.6    4.5  -14.5 60.04 *.*N
    -316   2304   -254   1808  -11.7   12.1   -2.6  -11.7   12.1   -2.6 60.04 *.*N
    -246   2387    279   2418   -8.6   -4.5   14.5   -8.6   -4.5   14.5 60.04 *.*N
[9]
     315  -2305    254  -1808   11.7  -12.1    2.6   11.7  -12.1    2.6 60.04 *.*N
     246  -2388   -279  -2418    8.6    4.5  -14.5    8.6    4.5  -14.5 60.04 *.*N
    -315   2304   -254   1807  -11.7   12.1   -2.6  -11.7   12.1   -2.6 60.04 *.*N
    -246   2388    279   2418   -8.6   -4.5   14.5   -8.6   -4.5   14.5 60.04 *.*N
[10]
     316  -2305    254  -1808   11.7  -12.1    2.6   11.7  -12.1    2.6 60.04 *.*N
     246  -2389   -279  -2419    8.6    4.5  -14.5    8.6    4.5  -14.5 60.04 *.*N
    -271   2025   -175   1636   -9.9    9.1   -0.8  -11.6   12.4   -2.5 60.04 *.*N
    -149   1496    212   1554   -5.2   -4.0   10.3   -8.7   -4.7   14.5 60.04 *.*N
[11]
     113   -874     48   -732    4.1   -3.1   -0.5   11.4  -13.2    2.3 60.04 *.*N
      26   -303    -72   -345    0.9    1.7   -3.0    9.0    5.0  -14.4 60.04 *.*N
      -0     -1      0     -0   -0.0   -0.0   -0.0  -11.3   13.5   -2.2 60.04 *.*N
      -0     -1     -0      0   -0.0    0.0   -0.0   -9.1   -5.3   14.4 60.04 *.*N
[12]
       0     -1      0      0    0.0    0.0    0.0   11.3  -13.5    2.2 60.04 *.*N
      -0      0      0     -0    0.0   -0.0   -0.0    9.1    5.3  -14.4 60.04 *.*N
       0     -1     -0     -0   -0.0   -0.0    0.0  -11.3   13.5   -2.2 60.04 *.*N ◄───┐
       0     -1     -0      0    0.0   -0.0   -0.0   -9.1   -5.3   14.4 60.04 *..N       ③
[13]
      -0      0     -1      0    0.0    0.0    0.0   11.3  -13.5    2.2 60.04 *..N
       0      0      0      0   -0.0   -0.0    0.0    9.1    5.3  -14.4 60.04 *..N
       0      0      0      0   -0.0   -0.0   -0.0  -11.3   13.5   -2.2 60.04 *..N
      -1     -0     -0     -0   -0.0    0.0   -0.0   -9.1   -5.3   14.4 60.04 *..N
[14]
      -0     -1     -0     -0    0.0   -0.0   -0.0   11.3  -13.5    2.2 60.04 *..N
       1      0      0     -0    0.0   -0.0   -0.0    9.1    5.3  -14.4 60.04 *..N
       0     -0      0      0   -0.0   -0.0    0.0  -11.3   13.5   -2.2 60.04 *..N
      -1     -0     -0     -0   -0.0    0.0   -0.0   -9.1   -5.3   14.4 60.04 *..N
[15]
       0      0     -0     -0    0.0    0.0   -0.0   11.3  -13.5    2.2 60.04 *..N
       0     -0      0      0   -0.0   -0.0    0.0    9.1    5.3  -14.4 60.04 *..N
      -0      1     -0      0   -0.0   -0.0    0.0  -11.3   13.5   -2.2 60.04 *..N
      -0     -0     -0      0   -0.0   -0.0   -0.0   -9.1   -5.3   14.4 60.04 *..N
```

Figure 12.8   Example Standard 15-Cycle Event Report 1/4-Cycle Resolution (Continued)

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```
Protection and Control Elements
51     50    32 Dm 27 59    27 59    25 81   TS TS TS   T 200  100
       A        Y  Y     Z  Z     5  2    ih Bih Cih ZL C  In   Out In       These columns are only
    GG B     P PN P  PV    P  PV    9S 7135 7mo 7mo 7mo lO PA 1135 13571357     displayed if extra Inputs/
ABCP12QCPNGQ QG QG PP PP1NQ PP PP1NQ VFA B246 9et 9et 9et dP SP 2246 2468246   Outputs are ordered
[1]
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
[2]
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
[3]
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
[4]
............ .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........        ⑬
.......... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
....p...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........>
[5]
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
[6]
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........        ⑪
...pp...... .. .. .. 3.... .. 3.... ... .... R.O ... ... .. 1* 1.b. ........
...pt...... .. .. .. 3.... .. 3.... ... .... L.O ... ... .. 1* 1.b. ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.b. ........     ⑩
[7]
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.b. ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.b. ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.135 ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
[8]
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
[9]
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
[10]
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1... ........
...pt...... .. .. .. c.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
[11]
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
...pt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
...rt...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
[12]
...r1...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1.3. ........
...r1...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1b3. ........       ②
...r1...... .. .. .. 3.... .. 3.... ... .... Lr3 ... ... .. 1* 1b3. ........
....1...... .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
[13]
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
[14]
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
[15]
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
............ .. .. .. 3.... .. 3.... ... .... L.3 ... ... .. 1* 1b3. ........
```

Figure 12.8   Example Standard 15-Cycle Event Report 1/4-Cycle Resolution (Continued)

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```
Mirrored Bits, Communication and Automation Elements
 S TMB  RMB  TMB  RMB  RRCL Lcl Rem   Ltch   SELogic            PWR
 O A    A    B    B    OBBB           1 Variable              3P PB
PT 1357 1357 1357 1357 KAAO 135 13570C 135791        1111111  13 10
OF 2468 2468 2468 2468  DDK 246 2468PL 246802 1234567890123456 24 92
[1]
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[2]
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[3]
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[4]
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..>
[Six cycles of data not shown in this example]
[11]
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[12]
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 .. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[13]
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[14]
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
[15]
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..
 3. .... .... .... .... .... .. ...... 1.b... ................ .. ..


 Event: BG  Location:   3.02  Shot: 0  Frequency:  60.01
 Targets: 11 100101001000 001000000111
 Currents (A Pri), ABCGQ:    400  3320   377  3019  3232


 Group Settings

 Identifier and Instrument Transformer Settings:
 RID    :=MOUNTAIN F-22
 TID    :=P180
 CTR    := 1000.0   CTRN    := 1000.0   PTRY    := 120.00   PTRZ    := 120.00
 .
 .
 [The remainder of the Group settings are not shown in this example]


 Logic Settings
 .
 .
 [The Logic settings are not shown in this example]
```

see Figure 12.2

Figure 12.8   Example Standard 15-Cycle Event Report 1/4-Cycle Resolution (Continued)

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```
Global Settings:

General Settings:
NFREQ   := 60        PHROT   := ABC       DATE_F  := MDY
PWRDN_AC:= 180       PWRDN_WU:= 20
TESTBATT:=NA
FAULT   :=51P OR 51G1

Current and Voltage Connection Settings:
IPCONN  := ABC       EGNDSW  := Y         CTPOL   := POS
BKTYP   := 1
VYCONN  := ABC       VZCONN  := OFF
VSELECT := VY        FSELECT := VY        METHRES := N
.
.
.
[The remainder of the Global settings are not shown in this example]

Report Settings

Sequential Events Recorder Trigger Lists:
SER1    :=TRIP3P,51P,51PT,51G1,51G1T,PB12_PUL,OC3
SER2    :=CLOSE3P,52A3P,CF3P,79RS3P,79CY3P,79LO3P,RCSF3P,SHO3P,SH13P,SH23P
SH33P,SH43P,PB11_PUL,CC3
SER3    :=PWR_SRC1,TOSLP,BTFAIL,DTFAIL
SER4    :=0

Event Report Settings:
LER     := 15        PRE     := 4
ER      :=R_TRIG 51P OR R_TRIG 51G1


.
.
.
[The remainder of the Report settings are not shown in this example]

PARTNO=0651R2XXXXXXXXXXXXXXXX
=>
```

Figure 12.8   Example Standard 15-Cycle Event Report 1/4-Cycle Resolution

Figure 12.9 and *Figure 12.10* look in detail at one cycle of A-phase current (channel IA) identified in *Figure 12.8*. *Figure 12.9* shows how the event report ac current column data relate to the actual sampled waveform and rms values. *Figure 12.10* shows how the event report current column data can be converted to phasor rms values. Voltages are processed similarly.

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NOTE: The arctan function of many calculators and computing programs does not return the correct angle for the second and third quadrants (when X is negative). When in doubt, graph the X and Y quantities to confirm that the angle that your calculator reports is correct.
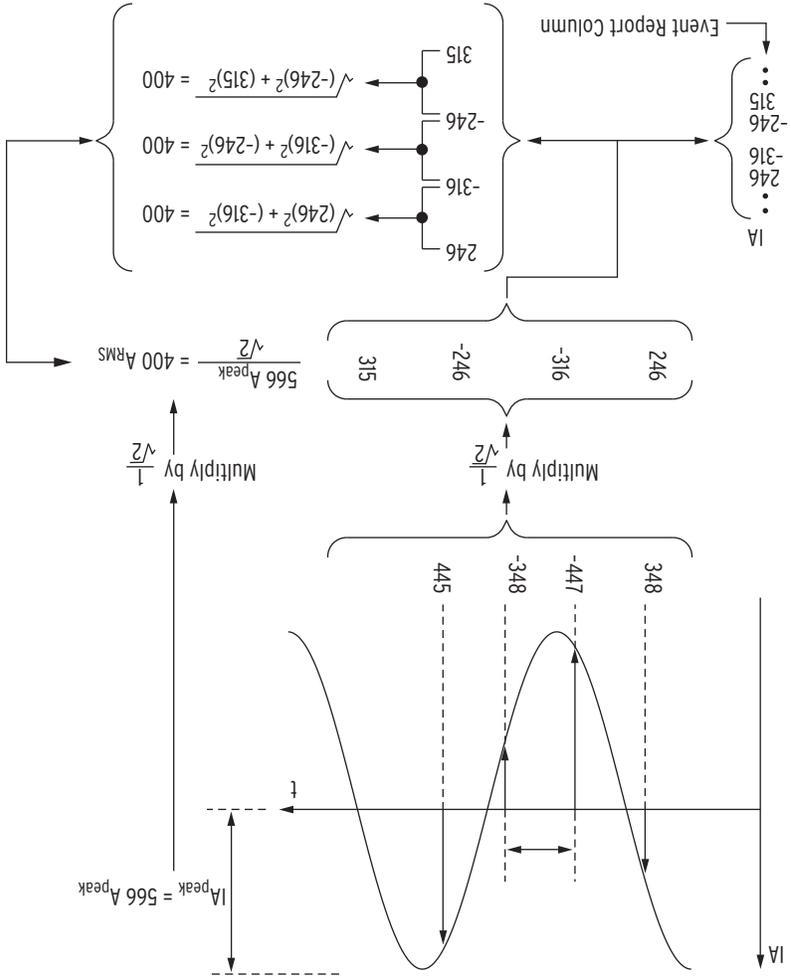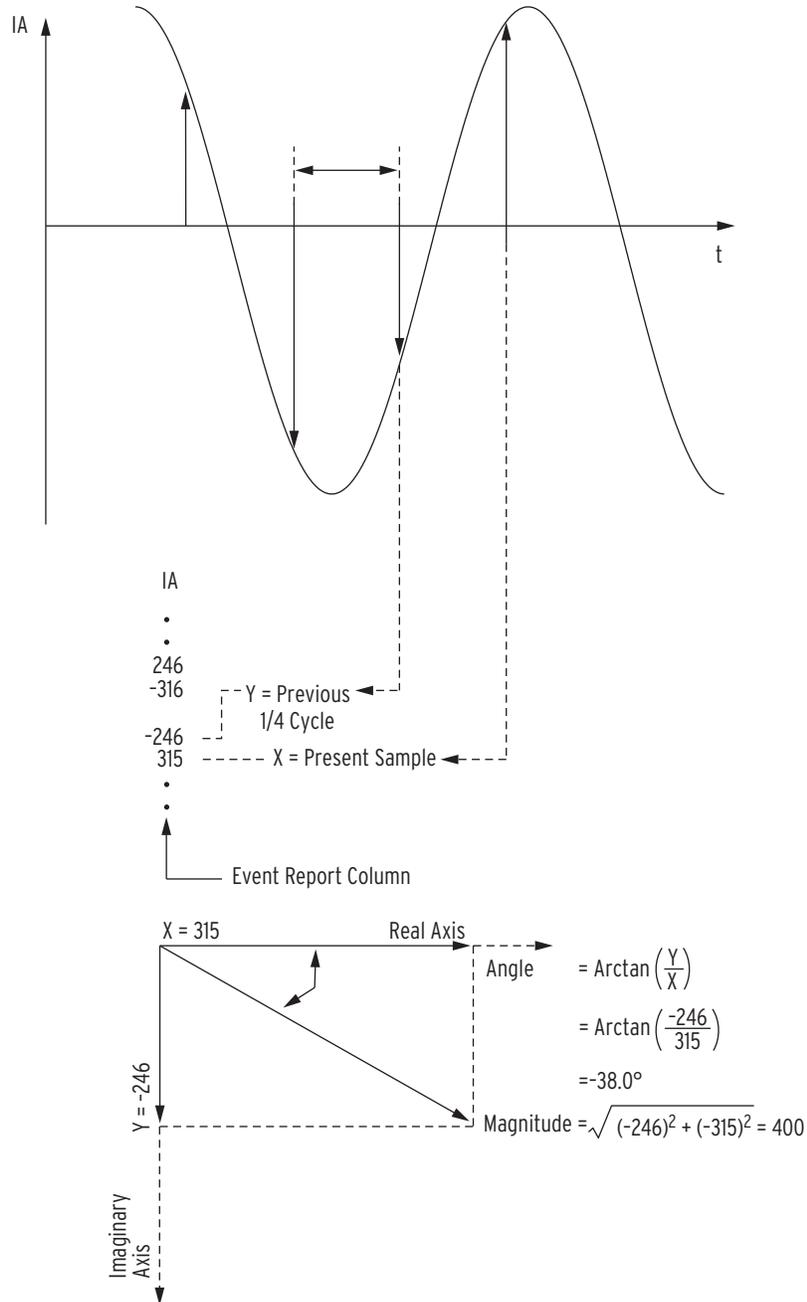
Figure 12.10   Derivation of Phasor RMS Current Values From Event Report Current Values

In *Figure 12.10*, note that two rows of current data from the event report in *Figure 12.8*, 1/4 cycle apart, can be used to calculate phasor rms current values. In *Figure 12.10*, at the present sample, the phasor rms current value is:

$$IA \ = \ 400 \text{ A} \ \angle -38.0°$$

Equation 12.1

The present sample (IA = 315 A) is a real rms current value that relates to the phasor rms current value:

$$400 \text{ A} * \cos(-38.0°) \ = \ 315 \text{ A}$$

Equation 12.2

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Sequential Events Recorder (SER) Report

See *Figure 12.11* for an example SER report.

SER Triggering

The recloser control triggers (generates) an entry in the SER report for a change of state of any one of the elements listed in the SER1, SER2, SER3, and SER4 trigger settings. The factory-default settings are:

SER1 := **TRIP3P, 51P, 51PT, 51G1, 51G1T, PB12_PUL, OC3**

SER2 := **CLOSE3P, 52A3P, CF3P, 79RS3P, 79CY3P, 79LO3P, RCSF3P, SHO3P, SH13P, SH23P, SH33P, SH43P, PB11_PUL, CC3**

SER3 := **PWR_SRC1, TOSLP, BTFAIL, DTFAIL**

SER4 := **0**

The elements are Relay Word bits referenced in *Table F.1*. The recloser control monitors each element in the SER lists every 1/4 cycle. If an element changes state, the recloser control time-tags the changes in the SER. For example, setting SER1 contains:

➤ Ground time-overcurrent element picked-up status (51G1)

➤ Ground time-overcurrent element timed-out status (51G1T)

If a ground fault occurs, the 51G1 element will assert and the change will be time-tagged in the SER (shown as `51G1 Asserted`). If the fault clears before the ground time-overcurrent element times-out (indicating that a load-side device or another element operated to clear the fault), the 51G1 element deassertion is time-tagged in the SER (shown as `51G1 Deasserted`).

If the ground fault did not get cleared by another device, then the 51G1T element would have asserted, and this state change would also appear in the SER (51G1T Asserted).

In addition to the programmable SER trigger lists, the recloser control adds preprogrammed messages to the SER for certain occurrences, as shown in *Table 12.6*.

Table 12.6   Automatic SER Triggers

Event	SER Entry[a]	Reference
Recloser control powered up after being shut off	`Relay restarted`	*Section 9: Settings*
Recloser control settings changed (except port settings)	`Settings changed`	*Section 9: Settings*, *Appendix L: IEC 61850*
Active settings group changed	`Group changed`	*Section 7: SELOGIC Control Equation Programming*
SER C command issued	`SER archive cleared`	*Clearing SER Report on page 12.40*
Start of SER data loss	`SER data loss begin`	*SER Memory Operation on page 12.40*
End of SER data loss	`SER data loss end`	
Invalid SER data	`Invalid Data`	
Data overwritten while recloser control is responding to **SER** command	`Command aborted, data overwrite occurred`	
Diagnostic restart	`Diagnostic restart`	*Section 13: Testing and Troubleshooting*
Recloser control shuts down while running on batteries	`Going to sleep`	*Section 13: Testing and Troubleshooting*

[a] Each entry in the SER except `Invalid Data` and `Command aborted, data overwrite` occurred includes a date and time stamp.

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Making SER Trigger Settings

Enter as many as 24 element names in each of the SER settings via the **SET R** command. See *Table F.1* for references to valid recloser control element (Relay Word bit) names. See the **SET R** command in *Table 9.2* and corresponding *Report Settings on page SET.64*. Use commas to delimit the elements. For example, if you enter setting SER1 as:

SER1 := **51P,51G1,51PT,,51G1T , 50P1, , 50P2**

The recloser control displays the setting as:

```
SER1 := 51P,51G1,51PT,51G1T,50P1,50P2
```

The recloser control can monitor as many as 96 elements in the SER (24 in each of SER1, SER2, SER3, and SER4).

Make SER Settings With Care

The recloser control triggers a row in the SER report for any change of state in any one of the elements listed in the SER1, SER2, SER3, or SER4 trigger settings. Nonvolatile memory is used to store the latest 1024 rows of the SER report so they can be retained during power loss. The nonvolatile memory is rated for a finite number of write cycles. Exceeding the limit can result in a FLASH self-test failure. *An average of one (1) state change every three minutes can be made for a 25-year recloser control service life.*

Retrieving SER Reports

See *SER Command (Sequential Events Recorder Report) on page 10.67* for details on the **SER** command.

Clearing SER Report

NOTE: If any elements change state during the clearing process, the SER entries for these elements may be reported with time stamps that are prior to the `SER archive cleared` message.

Clear the SER report from nonvolatile memory with the **SER C** command as shown in the following example:

```
=>SER C <Enter>
Clear the SER
Are you sure (Y/N) ? Y <Enter>
Clearing Complete
```

To indicate when the SER memory was cleared, an entry is added to the SER as shown in *Table 12.6*.

SER Memory Operation

The Sequential Events Recorder (SER) nonvolatile memory is updated soon after new SER data are generated. During some conditions, such as during event report capture, the update of SER data is momentarily interrupted, and then SER updating of nonvolatile memory resumes.

In rare cases with rapidly occurring SER triggers, the new SER information may arrive faster than the memory system can store it. When this occurs, the relay inserts a pair of entries in the SER to indicate the start and end of data loss, as shown in *Table 12.6*. This is normally seen only during testing. Normal SER operation resumes after the data loss.

Another situation that can affect SER data storage is when the power supply to the SEL-651R-2 is interrupted while data are being recorded. If this results in incomplete data, the **SER** command may report `Invalid Data` for the incomplete entry, as shown in *Table 12.6*. Normal SER operation resumes after the relay is powered up.

Example SER Report

The following example SER report in *Figure 12.11* also corresponds to the example standard 15-cycle event report in *Figure 12.8*.

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Sequential Events Recorder (SER) Report

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```
=>SER <Enter>

FEEDER 1                         Date: 03/21/2012 Time: 15:53:49.924
STATION A                        Time Source: internal

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx CID=xxxx

  #    Date      Time           Element         State

 22  01/06/2012 11:47:41.430   Relay restarted
 21  01/06/2012 11:47:41.430   52A3P           Asserted
 20  01/06/2012 11:47:41.430   PWR_SRC1        Asserted
 19  01/06/2012 11:47:41.430   SH33P           Asserted
 18  01/06/2012 11:47:41.430   79LO3P          Asserted
 17  01/06/2012 11:47:51.522   79LO3P          Deasserted
 16  01/06/2012 11:47:51.522   79RS3P          Asserted
 15  01/06/2012 11:47:51.526   SH33P           Deasserted
 14  01/06/2012 11:47:51.526   SH03P           Asserted
 13  03/02/2012 17:06:35.961   51G1            Asserted
 12  03/02/2012 17:06:35.965   51P             Asserted
 11  03/02/2012 17:06:35.994   51G1T           Asserted
 10  03/02/2012 17:06:35.994   79LO3P          Asserted
  9  03/02/2012 17:06:35.994   79RS3P          Deasserted
  8  03/02/2012 17:06:35.994   TRIP3P          Asserted
  7  03/02/2012 17:06:35.999   SH33P           Asserted
  6  03/02/2012 17:06:35.999   SH03P           Deasserted
  5  03/02/2012 17:06:36.082   51P             Deasserted
  4  03/02/2012 17:06:36.086   51G1            Deasserted
  3  03/02/2012 17:06:36.099   52A3P           Deasserted
  2  03/02/2012 17:06:36.103   51G1T           Deasserted
  1  03/02/2012 17:06:36.665   TRIP3P          Deasserted

=>
```

Figure 12.11   Example SER Report

The SER report rows in *Figure 12.11* are explained in *Table 12.7*, numbered in correspondence to the # column. The circled comments in *Figure 12.8* also correspond to the # column numbers in *Figure 12.11*. The SER report in *Figure 12.11* contains records of events that occurred before and after the standard event report in *Figure 12.8*.

Table 12.7   Example SER Detailed Description[a]

SER Row No.	Explanation
22–20	SEL-651R-2 powered up.[b]
19–14	Reclosing relay initialization after turning on.
13	Ground #1 time-overcurrent element pickup (51G1). Starts timing at fault inception.
12	Maximum-phase time overcurrent element pickup (51P). Also starts timing.
11–8	Ground #1 time-overcurrent element times out (51G1T) and asserts trip logic (TRIP3P). Reclosing relay goes into the lockout state. Lockout occurs because **Reclose Enabled** operator control (= LT02) is deasserted.
7–6	Reclosing relay shot counter moves to last shot.
5–4	Time overcurrent elements drop out (51P and 51G1) as recloser contacts interrupt the fault current.
3	Recloser status change—52A3P registers as open.
2	Ground #1 time-overcurrent element completes 1-cycle reset interval (51G1T deasserts).
1	Trip logic drops out.

[a] Corresponds to Figure 12.13.
[b] The date is a few months before the event report in Figure 12.8.

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Analyzing Events
Sag/Swell/Interruption (SSI) Report

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Sag/Swell/Interruption (SSI) Report

See *Figure 12.12* for an example SSI report.

SSI Triggering and Recording

NOTE: SSI is not available on models ordered with a single voltage input.

The SEL-651R-2 can perform automatic voltage disturbance monitoring for three-phase systems. The SSI Recorder uses the SSI Relay Word bits to determine when to start (trigger) and when to stop recording. The recorded data are available through the SSI Report.

See *Voltage Sag, Swell, and Interruption Elements on page 4.59* for details on the operation of the SSI Relay Word bits.

The SSI recorder operates (adds new entries to the stored SSI report) only when Group setting ESSI := Y in the active settings group, although the SSI report can be viewed at any time.

The SSI recorder uses nonvolatile memory, so any stored SSI data will not be erased by de-energizing the recloser control. The recloser control needs some time to store new SSI data in nonvolatile memory, so if a system power outage also causes the recloser control power to fail, there may not be an SSI record of the disturbance. The battery system in the SEL-651R-2 will normally keep the recloser control operating through any voltage disturbances.

The recloser control triggers (generates) entries in the SSI report upon the assertion of any sag, swell, or interruption element (Relay Word bits SAGp, SWp, INTp, where p = A, B, or C), when manually triggered by the **SSI T** command or when the SSI_TRIG SELOGIC control equation solves to logical 1. See *Voltage Sag/Swell/Interrupt on page SET.33* for the SSI_TRIG equation.

SSI Report Entries

➤ Entry number (1 is the most recent entry)

➤ Date and time stamp of entry

➤ Phase current magnitudes (Ia, Ib, Ic) as a percentage of the nominal current rating of the phase current inputs (1 A)

➤ Ground current magnitude (Ig) as a percentage of the nominal current rating of the phase current inputs (1 A)

GLOBAL SETTING EGNDSW
See Ground Switch Logic on page 4.76.

Note: When Global setting EGNDSW := Y, the Ig percentage magnitude is based on channel IN data for small signals when Relay Word bit GNDSW is asserted. The percentage value displayed will be 1/5 of the displayed In percentage value, because of the difference in nominal channel ratings; the 1 A phase channel nominal rating is five times the 0.2 A nominal neutral channel rating.

For large signals, the Ig quantity is based on a calculated residual zero-sequence current 3I0 = IA + IB + IC when Relay Word bit GNDSW is deasserted. When Global setting EGNDSW := N, Ig is always based on the calculated 3I0 quantity.

➤ Neutral current magnitude (In) as a percentage of the nominal current rating of the neutral current input (0.2 A)

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Sag/Swell/Interruption (SSI) Report

➤ Phase-neutral voltage magnitudes (Va, Vb, Vc) as a percentage of Vbase

Global setting VSELECT determines which input terminals are monitored by the SSI elements, as shown in the SSI report. For example, if VSELECT := VZ, quantities VAZ, VBZ, and VCZ are reported. The other three voltage quantities (VAY, VBY, and VCY) have no effect on the SSI elements or the SSI report.

➤ Base voltage magnitude (Vbase) in kV primary
Vbase = memorized positive-sequence voltage, V_1

➤ Phase A, B, and C SSI element status columns (see *Table 12.8)*

➤ Trigger state, ⋆ if present (in the column marked S)

➤ SSI recorder status (see *Table 12.9*)

NOTE: Any current or voltage value greater than 999 percent will be replaced by "$$$" in the SSI report.

Table 12.8   SSI Element Status Columns

Symbol	Meaning (for Each Column A, B, or C)
	Column A represents p = A Column B represents p = B Column C represents p = C
•	No SSI bits asserted for phase p
O	Overvoltage (SWp asserted)
U	Undervoltage (SAGp asserted)
I	Interruption (INTp asserted; SAGp asserted, unless setting VSAG := OFF)

Table 12.9   Recorder Status Column

Symbol	Meaning (Action)	Duration
R	Ready (when the SSI logic first acquires a valid V_{BASE} value)	Single entry
P	Predisturbance (4 samples per cycle). Always signifies a new disturbance.	12 samples (3 cycles)
F	Fast recording mode (4 samples per cycle)	Varies. At least one SSI element must be asserted.
E	End (post-disturbance at 4 samples per cycle)	As long as 16 samples (4 cycles). No SSI elements asserted.
M	Medium recording mode (one sample per cycle)	Maximum of 176 cycles
S	Slow recording mode (one sample per 64 cycles)	Maximum of 4096 cycles
D	Daily recording mode (one sample per day, just after midnight)	Indefinite
X	Data overflow (single entry that indicates that data were lost prior to the present entry)	Single entry

See *Figure 12.12* for an example SSI report.

SSI Recorder Operation: Overview

The SSI recorder operation can be summarized as follows: When power is first applied to the recloser control and setting ESSI := Y, (or setting ESSI is changed from N to Y), the recloser control measures the voltage inputs specified by Global setting VSELECT to determine if a valid three-phase signal is present. When the conditions are satisfied for at least twelve seconds,

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the positive-sequence voltage, V_1, is memorized as the Vbase reference voltage. This causes a single R entry to be placed in the SSI archive, which indicates that the recorder is armed, or ready. The Vbase value is allowed to change on a gradual basis to follow normal system voltage variations, but is locked when a disturbance occurs.

When any SSI Relay Word Bit asserts, the SSI_TRIG SELOGIC control equation is asserted, or the **SSI T** serial port command is issued, the recorder will begin recording.

When operating, the SSI Recorder archives the following information:

➤ Currents Ia, Ib, Ic, Ig, and In as a percentage of the nominal current rating (shown in the report heading)

➤ Voltages Va, Vb, and Vc as a percentage of the Vbase quantity

➤ The Vbase quantity in kV primary

➤ The state of the SSI Relay Word bits by phase

➤ The trigger status

➤ The recorder status

Entries are made at a varying recording rate: fastest when the SSI Relay Word bits are changing states, and slowest if the SSI Relay Word bits are quiet. Eventually, it can get as slow as one sample per day. The faster recording mode will be initiated from any of the slower recording modes, as soon as any SSI bit or the **SSI T** condition changes state.

Recording is stopped when all SSI Relay Word bits and the trigger condition stay deasserted for at least four cycles.

The Group setting SSI_TRIG is a SELOGIC control equation that can be used to force the SSI recorder to trigger, regardless of the applied voltages, provided that the recorder was previously armed. The SSI_TRIG setting is treated the same as a Sag/Swell/Interruption Relay Word bit. An example application is to set SSI_TRIG := PB08_PUL for testing purposes. When the Operator Control pushbutton **AUX 1** is pressed, the SSI recorder would act as if the **SSI T** command was issued (see *Table 11.9*).

Make SSI_TRIG Setting With Care

Take care to set the SSI_TRIG equation so that it does not constantly assert and deassert, because the resulting stream of SSI triggers causes excessive data recording. Excessive recording reduces the usefulness of the SSI report for actual power system disturbance analysis because real disturbance data could be overwritten before an operator could retrieve the information. Additionally, because the SSI data are stored in nonvolatile memory that is rated for a finite number of write cycles, constant SSI triggering could lead to a FLASH self-test failure and a reduction in the recloser control service life.

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Sag/Swell/Interruption (SSI) Report

SSI Recorder Operation: Detailed Description

From the SSI Recorder Ready state, upon the initial assertion of one of the SSI Relay Word bits or a manual trigger condition, the recloser control records SSI data in the following sequence:

➤ **Predisturbance recording:** Record pretrigger entries at ¼-cycle intervals with the SSI recorder status field displaying P. Because no SSI elements are asserted, columns A, B, and C display "." (a period). The predisturbance state lasts for a total of 12 samples, or 3 cycles, unless there are back-to-back disturbances that reduce the number of P entries.

➤ **Fast recording (also End recording):** Record one entry every ¼-cycle, with the SSI recorder status field displaying F (if any SSI elements are asserted or the trigger condition is asserted), or E (if none of the SSI elements are asserted). If the trigger condition is present, a * is recorded. The SSI element status columns show one of ., 0, U, I. The Fast/End recording mode continues until four cycles elapse with no SSI element or trigger condition changing state. The recloser control then proceeds to the state determined by the following tests (processed in the order shown):

  ➤ If INT3P is asserted, switch to daily recording mode. This keeps the recloser control from recording medium and slow speed detailed information during a complete outage.

  ➤ Otherwise, if any SSI elements or the SSI_TRIG setting are asserted, switch to the medium recording mode.

  ➤ Otherwise, stop recording.

➤ **Medium recording:** Record one entry per cycle, with the SSI recorder status field displaying M. The phase columns show one of ., 0, U, I. The medium recording mode continues for 176 cycles, unless one of the SSI elements or the trigger condition changes state, which causes the recorder to start over in Fast mode (with as many as three samples prior to the change). At the end of medium recording mode, the recorder switches to the slow recording mode.

➤ **Slow recording:** Record one entry every 64 cycles, with the SSI recorder status field displaying S. The phase columns show one of ., 0, U, I. The slow recording mode continues for 4,096 cycles (64 entries), unless one of the SSI elements or the manual trigger condition changes state, which causes the recorder to start over in fast mode (with as many as eight samples prior to the change). At the end of slow recording mode, the recorder switches to the daily recording mode.

➤ **Daily recording:** Record one entry every day just past midnight (00:00:00), with the SSI recorder status field displaying D. The phase columns show one of ., 0, U, I. The daily recording mode continues until any SSI relay element or the manual trigger condition changes state, which causes the recorder to start over in fast mode with as many as eight samples prior to the change.

An overflow condition can occur when the SSI recorder cannot keep up with the data generated during disturbances that create a large number of SSI entries. The nonvolatile memory that is used for the SSI archive has a longer write time than the random-access memory (RAM) that is used to temporarily store the SSI data, so it is possible that the recloser control will overwrite the

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data in RAM if the transfer to Flash memory gets too far behind. The SSI report shows an X in the REC column if this happens, and it is on the first entry after the overflow. The overflow condition may also occur if the recloser control is saving an event report to nonvolatile memory, because the memory can only be used by one procedure at a time.

SSI Report Memory Details

The recloser control retains a minimum of 4000 of the most recent SSI entries in nonvolatile memory. The recloser control can hold a maximum of approximately 8000 entries. When the recorder memory reaches 8000 entries and further entries occur, the oldest 4000 memory locations are cleared in a block to make room for newer entries. Therefore, the apparent SSI memory size can vary between 4000 and approximately 8000 entries. If the SSI recorder memory clears while an SSI report is being displayed, the SSI report stops and displays this message:

```
Command Aborted, Data overwrite occurred
```

Capacity of the SSI Report

If maximum SSI recorder capacity is desired, the SSI report should be checked periodically, with the data captured to a computer file by using a terminal emulation program. Once the data have been viewed or captured, use the **SSI C** command to clear the SSI recorder.

Clearing the SSI recorder makes it easier to tell if any new disturbances have been recorded, and it also allows the SSI archive to record the maximum of 8000 entries. If more than 8000 entries occur, the oldest half of the SSI archive will be erased to make room for the new entries. The most recent 4000 entries are always available.

Retrieving the SSI Report

See *SSI Command (Voltage Sag/Swell/Interruption Report) on page 10.69* for details on the **SSI** command. See *Figure 12.12* for an example SSI report.

Commissioning Testing

The **SSI T** command is useful for testing, because it provides an easy method of creating some SSI report entries without the need to remove voltage signals or connect a test set, providing Vbase has already been initialized.

During recloser control commissioning or test procedures, the SSI recorder may memorize the Vbase quantity when test voltages or settings are applied. This could cause the recorder to declare a false SAG or SWELL condition when normal system voltages are applied. Reset the SSI recorder logic and clear the Vbase value by issuing the **SSI R** command.

Example SSI Report

The SSI report in *Figure 12.12* shows the voltage disturbances caused by the same fault simulation used for *Figure 12.8* (example event report) and *Figure 12.11* (example SER report). Notice in *Figure 12.12* that the Vb column shows the voltage sag, and the Ph B column shows a U, representing the SAGB Relay Word bit. Currents Ib and Ig display the fault current.

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High-Impedance Fault (HIF) Event Reporting
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```
=>SSI <Enter>

FEEDER 1                              Date: 03/21/2012 Time: 16:36:19.451
STATION A                             Time Source: internal

FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx CID=xxxx

                    I nom. A B C G = 1 Amp   N = 0.20 Amp


                          Current(% I nom.)   Voltage(% Vbase) Vbase  Ph ST
#     Date       Time      Ia   Ib  Ic  Ig  In  Va  Vb  Vc     (kV)   ABC
47  07/02/2003 17:06:35.949  27   27  27   0   0 100 100 100   14.37 ... P
46  07/02/2003 17:06:35.953  27   27  27   0   0 100 100 100   14.37 ... P
45  07/02/2003 17:06:35.957  27   27  27   0   0 100 100 100   14.37 ... P
44  07/02/2003 17:06:35.961  29   47  28  16  78 101  98 100   14.37 ... P
43  07/02/2003 17:06:35.965  29   99  27  90 449 100  97 101   14.37 ... P
42  07/02/2003 17:06:35.969  33  173  31 138 690 102  93 101   14.37 ... P
41  07/02/2003 17:06:35.974  33  256  30 235 $$$ 101  92 102   14.37 ... P
40  07/02/2003 17:06:35.978  35  310  33 277 $$$ 101  90 102   14.37 ... P
39  07/02/2003 17:06:35.982  35  332  33 302 $$$ 101  90 103   14.37 ... P
38  07/02/2003 17:06:35.986  35  332  33 302 $$$ 101  90 103   14.37 ... P
37  07/02/2003 17:06:35.990  35  332  33 302 $$$ 101  90 103   14.37 ... P
36  07/02/2003 17:06:35.994  35  332  33 302 $$$ 101  90 103   14.37 ... P
35  07/02/2003 17:06:35.999  35  332  33 302 $$$ 101  90 103   14.37 .U. F
34  07/02/2003 17:06:36.003  35  332  33 302 $$$ 101  90 103   14.37 .U. F
33  07/02/2003 17:06:36.007  35  332  33 302 $$$ 101  90 103   14.37 .U. F
32  07/02/2003 17:06:36.011  35  332  33 302 $$$ 101  90 103   14.37 .U. F
31  07/02/2003 17:06:36.015  35  332  33 302 $$$ 101  90 103   14.37 .U. F
30  07/02/2003 17:06:36.019  35  332  33 302 $$$ 101  90 103   14.37 .U. F
29  07/02/2003 17:06:36.024  35  332  33 302 $$$ 101  90 103   14.37 .U. F
28  07/02/2003 17:06:36.028  35  332  33 302 $$$ 101  90 103   14.37 .U. F
27  07/02/2003 17:06:36.032  35  332  33 302 $$$ 101  90 103   14.37 .U. F
26  07/02/2003 17:06:36.036  35  332  33 302 $$$ 101  90 103   14.37 .U. F
25  07/02/2003 17:06:36.040  35  332  33 302 $$$ 101  90 103   14.37 .U. F
24  07/02/2003 17:06:36.044  35  332  33 302 $$$ 101  90 103   14.37 .U. F
23  07/02/2003 17:06:36.049  35  332  33 302 $$$ 101  90 103   14.37 .U. F
22  07/02/2003 17:06:36.053  35  332  33 302 $$$ 101  90 103   14.37 .U. F
21  07/02/2003 17:06:36.057  35  332  33 302 $$$ 101  90 103   14.37 .U. F
20  07/02/2003 17:06:36.061  32  313  29 292 $$$ 100  92 103   14.37 .U. F
19  07/02/2003 17:06:36.065  27  252  24 226 $$$ 101  92 103   14.37 .U. F
18  07/02/2003 17:06:36.069  16  173  19 172 859 100  97 102   14.37 .U. F
17  07/02/2003 17:06:36.074  10   93   8  81 405 101  98 102   14.37 .U. F
16  07/02/2003 17:06:36.078   2   30   6  34 172 101 100 102   14.37 ... E
15  07/02/2003 17:06:36.082   0    0   0   0   0 101 101 101   14.37 ... E
14  07/02/2003 17:06:36.086   0    0   0   0   0 101 101 101   14.37 ... E
13  07/02/2003 17:06:36.090   0    0   0   0   0 101 101 101   14.37 ... E
12  07/02/2003 17:06:36.094   0    0   0   0   0 101 101 101   14.37 ... E
11  07/02/2003 17:06:36.099   0    0   0   0   0 101 101 101   14.37 ... E
10  07/02/2003 17:06:36.103   0    0   0   0   0 101 101 101   14.37 ... E
 9  07/02/2003 17:06:36.107   0    0   0   0   0 101 101 101   14.37 ... E
 8  07/02/2003 17:06:36.111   0    0   0   0   0 101 101 101   14.37 ... E
 7  07/02/2003 17:06:36.115   0    0   0   0   0 101 101 101   14.37 ... E
 6  07/02/2003 17:06:36.119   0    0   0   0   0 101 101 101   14.37 ... E
 5  07/02/2003 17:06:36.124   0    0   0   0   0 101 101 101   14.37 ... E
 4  07/02/2003 17:06:36.128   0    0   0   0   0 101 101 101   14.37 ... E
 3  07/02/2003 17:06:36.132   0    0   0   0   0 101 101 101   14.37 ... E
 2  07/02/2003 17:06:36.136   0    0   0   0   0 101 101 101   14.37 ... E
 1  07/02/2003 17:06:36.140   0    0   0   0   0 101 101 101   14.37 ... E

=>
```

Figure 12.12   Example Sag/Swell/Interruption (SSI) Report

High-Impedance Fault (HIF) Event Reporting

High-impedance fault event information is available when the relay supports HIF detection. The relay stores event information in nonvolatile memory. High-impedance fault event information can be viewed in one or more of the following forms:

➤ HIF event summary

➤ HIF event history

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➤ Compressed ASCII HIF Event Report

➤ COMTRADE File Format HIF Event Report

HIF Event Report Storage

The SEL-651R-2 provides user-selectable HIF event report length. Report setting HIFLER determines the length of the event report. HIF event report length is either 2, 5, 10, or 20 minutes. The prefault length, contrary to the standard event report, is fixed at 90 seconds and is included in addition to the HIFLER setting (i.e., when HIFLER equals 2 minutes, the total event report will be 3 minutes and 30 seconds).

See the **SET R** command in *Table 9.2* and corresponding *Report Settings on page SET.64* for instructions on setting the HIFLER setting. Changing the HIFLER setting erases all HIF events stored in nonvolatile memory.

The HIF event report capacity depends on the selected report length (HIFLER) setting, as shown in *Table 12.10*.

NOTE: During testing, be aware that once the relay HIF event report memory is full, triggering a new HIF event can displace the oldest events.

Table 12.10   HIF Event Report Length Settings

HIFLER settings (minutes):	2	5	10	20
Minimum Number of Event Reports Stored:	28	14	7	3

HIF Event Summary

The **SUM HIF** command displays a shortened version of a stored high-impedance fault event report. These short-form reports present vital information about a triggered event. See *Figure 12.13* for a sample HIF event summary.

```
=>>SUM HIF <Enter>

FEEDER 1                        Date: 08/03/2012 Time: 08:52:15.854
STATION A                       Time Source: external

Event Number = 10000
Event: HIF Fault                HIF Phase: A,B
Downed Conductor: NO            Freq: 59.99
Breaker: CLOSED

Pre-trigger (A):
IARMS       IBRMS       ICRMS
312.0       238.0       282.0

Post-trigger (A):
312.0       245.0       281.0

Pre-trigger (A):
SDIA        SDIB        SDIC
236.5       203.5       211.5

Post-trigger (A):
247.0       217.0       224.0
Sample HIF Event Summary Report
```

Figure 12.13   Sample HIF Summary

The event summary contains the following information:

➤ Standard report header

➢ Relay and terminal identification

➢ Event date and time

➢ Relay Time Source

➤ Event type

➤ Event number (corresponding to the **HIS HIF** command)

➤ HIF Phase

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➤ Downed Conductor

➤ System frequency

➤ Breaker status at trigger time of the event

➤ Pretrigger and post-trigger phase RMS currents and sum of difference currents (from the first row and the initial trigger row of the event report)

Table 12.11 lists event types in fault reporting priority. The entire length of the event report is examined to determine the event type. For example, alarm event types have reporting priority over triggered events when both conditions are present in an event. Events may be triggered in one of two ways. The **TRI HIF** command triggers an event (see *TRI Command (Trigger Event Report) on page 10.79* for complete information on the **TRI** command) locally. Report setting HIFER allows for triggering an event automatically at the assertion of the corresponding Relay Word bit (see *Table 4.26 on page 4.112*).

Table 12.11   HIF Event Types

Event	Event Trigger
HIF FAULT	Assertion of any one of the following Relay Word bits: HIF2_A, HIF2_B, HIF2_C
HIF ALARM	Assertion of any one of the following Relay Word bits and if no HIF fault has occurred: HIA2_A, HIA2_B,HIA2_C
HIF Ext. TRI	Assertion of HIFER SELOGIC variable.
HIF TRI	Execution of the **TRI HIF** command.

Table 12.12 lists HIF phase involvement conditions. The phase involvement is determined by examining the entire event report. Multiple phases may be listed if more than one phase involvement is detected. If an HIF event occurs (Relay Word bits HIF2_A, HIF2_B, or HIF2_C assert), alarmed phases are not listed. When an event report is triggered, Relay Word bit HIFREC is asserted until the HIF event report is finished being collected. The relay does not generate additional event reports for triggering conditions that follow the initial triggering condition and are within the same report.

Table 12.12   HIF Event Phases

Phase	Conditions
A	Assertion of any one of the following Relay Word bits: HIA2_A, HIF2_A
B	Assertion of any one of the following Relay Word bits: HIA2_B, HIF2_B
C	Assertion of any one of the following Relay Word bits: HIA2_C, HIF2_C

When a high-impedance fault is caused by a down-conductor, there may be a load current reduction. Depending on the position of the down conductor and the amount of load dropped, this load reduction event may or may not be detectable at the recloser location. The Load Reduction Element is used to detect any load reduction at the time that a high-impedance fault is detected. The element is used to report a possible down-conductor event. *Table 12.13* lists HIF downed conductor conditions.

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Table 12.13   HIF Downed Conductor

Downed Conductor	Conditions
YES	Assertion of any one of the following Relay Word bits: HIA2_A, HIA2_B, HIA2_C, HIF2_A, HIF2_B, HIF2_C, AND LRX (LRA, LRB, LRC) bit asserts where X is the same phase as the alarmed or faulted phase.
NO	When the above is not true.

The system frequency is displayed as measured at the time of trigger to two decimal places. Pretrigger currents are obtained from the first row in the event report, while post-trigger currents are obtained from the initial trigger row.

Viewing the HIF Event Summary

Access the history report from the communications ports by using the **HIS HIF** command or the analysis menu within QuickSet. View and download HIF history reports from Access Level 1 and higher.

The **SUM HIF** command can be used to retrieve HIF event summaries by event number. (The relay labels each new event with a unique number as reported in the **HIS HIF** command history report; see *HIF Event History on page 12.51*.) *Table 12.14* lists the **SUM HIF** commands.

Table 12.14   SUM HIF Command

Command	Description
SUM HIF	Return the most recent HIF event summary.
SUM HIF *n*	Return an event summary for HIF event *n*[a].

[a] The parameter *n* indicates the event unique event identification number.

CSUMMARY HIF

The relay outputs a Compressed ASCII HIF summary report for SCADA and other automation applications. Issue ASCII command **CSU HIF** to view the Compressed ASCII HIF summary report. A sample of the summary report appears in *Figure 12.14*; this is a comma-delimited ASCII file. The relay appends a four digit hex checksum at the end of the lines in the Compressed ASCII report.

Items included in the Compressed ASCII summary report are similar to those included in the summary report.

See *CSUMMARY HIF Command (Only Available in Relays That Support Arc Sense Technology) on page C.10* for more information on the Compressed ASCII command set.
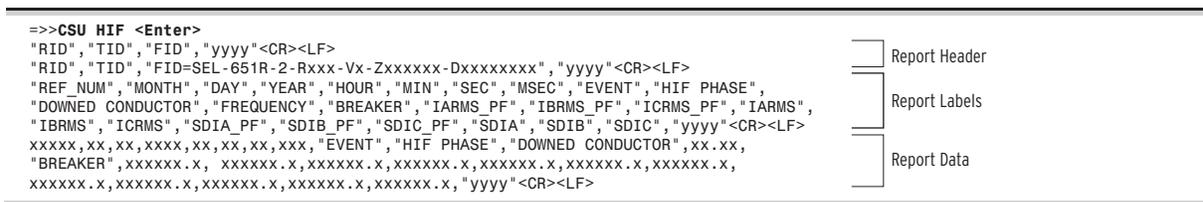
```
=>>CSU HIF <Enter>
"RID","TID","FID","yyyy"<CR><LF>                                          ⌐ Report Header
"RID","TID","FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","yyyy"<CR><LF>     └
"REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","EVENT","HIF PHASE",  ⌐
"DOWNED CONDUCTOR","FREQUENCY","BREAKER","IARMS_PF","IBRMS_PF","ICRMS_PF","IARMS",  │ Report Labels
"IBRMS","ICRMS","SDIA_PF","SDIB_PF","SDIC_PF","SDIA","SDIB","SDIC","yyyy"<CR><LF>  └
xxxxx,xx,xx,xxxx,xx,xx,xx,xxx,"EVENT","HIF PHASE","DOWNED CONDUCTOR",xx.xx,   ⌐
"BREAKER",xxxxxx.x, xxxxxx.x,xxxxxx.x,xxxxxx.x,xxxxxx.x,xxxxxx.x,xxxxxx.x,    │ Report Data
xxxxxx.x,xxxxxx.x,xxxxxx.x,xxxxxx.x,xxxxxx.x,"yyyy"<CR><LF>                   └
```

Figure 12.14   Sample Compressed ASCII HIF Summary

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High-Impedance Fault (HIF) Event Reporting

HIF Event History

The HIF event history gives a quick look at recent relay activity. See *Figure 12.15* for a sample event history. The HIF event history contains the following:

- ➤ Standard report header
  - ➢ Relay and terminal identification
  - ➢ Date and time of report
  - ➢ Relay Time Source
- ➤ Event number
- ➤ Date and time when event triggered
- ➤ Event type
- ➤ Downed Conductor
- ➤ Active settings group at time of event trigger

```
=>>HIS HIF <Enter>

FEEDER 1                        Date: 10/03/2012 Time: 08:39:15.855
STATION A                       Time Source: external

#        DATE       TIME        EVENT            DOWNED CONDUCTOR   GRP
10004  09/08/2012 09:56:40:797  HIF Alarm A,B,C        NO          1
10003  06/10/2012 08:04:16.698  HIF Fault B            NO          1
10002  06/09/2012 07:13:48.734  HIF Fault B            NO          1
10001  06/08/2012 15:07:13.293  HIF Fault A,B,C        NO          1
10000  06/08/2012 14:55:02.457  HIF TRI                NO          1
```

Figure 12.15   Sample HIF Event History

The event types and downed conductor status in the event history are determined in the same manner as in the event summary (see *HIF Event Summary on page 12.48*).

Viewing the HIF Event History

Access the history report from the communications ports by using the **HIS HIF** command or the analysis menu within QuickSet. View and download history reports from Access Level 1 and higher.

Use the **HIS HIF** command from a terminal to obtain the event history. The optional parameter *n* specifies the number of the most recent events that the relay returns.

Table 12.15   HIS HIF Command

Command	Description
HIS HIF	Return event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF *n*	Return the *n* most recent event summaries with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF C	Clears the HIF event history. The unique event identifier is not reset to 10000.

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CHISTORY HIF

The SEL-651R-2 provides Compressed ASCII event reports to facilitate event report storage and display. SEL communications processors and Analytic Assistant take advantage of the Compressed ASCII format. Use the **CHI HIF** command to display Compressed ASCII event history information.

```
=>>CHI HIF <Enter>
"RID","TID","FID","yyyy"<CR><LF>
"Relay 1","Station A","FID=SEL-xxx-Rxxx-Vx-xxxxxx-Dxxxxxxxx","yyyy"<CR><LF>
"REC_NUM","REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","EVENT",
"DOWNED CONDUCTOR","GRP","FREQ","yyyy"<CR><LF>
xx,xxxxx,xx,xx,xxxx,xx,xx,xx,xxx,"HIF TRI","NO",x,xx.xx,"yyyy"<CR><LF>
xxx,xxxxx,xx,xx,xxxx,xx,xx,xx,xxx,"HIF FAULT B","YES",xx.xx,"yyyy"<CR><LF>
```

Figure 12.16   Sample Compressed HIF History Report

HIF Event Reporting

High-impedance fault oscillography files are available when the relay supports HIF detection. In the SEL-651R-2, HIF events are available as Compressed ASCII reports and binary format via COMTRADE files. HIF event reports are available at the rate of 1-sample/2 cycles.

Use a terminal or SEL-supplied PC software to retrieve event report files stored in the relay and transfer these files to your computer. Both QuickSet and Analytic Assistant read the compressed event files that the relay generates for an event. See *QuickSet Event Analysis on page 3.18* for instructions on viewing event report oscillography with QuickSet.

High-Impedance Fault Compressed Event Report

The SEL-651R-2 provides Compressed ASCII event reports to facilitate event report storage and display. SEL communications processors and Analytic Assistant take advantage of the Compressed ASCII format. Use the **CEV HIF** command to display Compressed ASCII HIF event reports.

The relay generates compressed event reports to display analog data and the state of the HIF Relay Word bits.

The relay provides user-programmable event report triggering conditions. An event report is triggered for all conditions listed for the **SUM HIF** command. When an event report is triggered for any of these conditions, Relay Word bit, HIFREC, asserts, and stays asserted until the HIF event report has finished collecting. The relay does not generate additional event reports for triggering conditions that follow the initial triggering condition and are within the same report.

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```
=>CEV HIF <Enter>
"FID","yyyy"
"FID=SEL-xxx-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","yyyy"
"MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","yyyy"
xx,xx,xxxx,xx,xx,xx,xxx,"yyyy"
"REC_NUM","REF_NUM","NUM_CH_A","NUM_CH_D","SAM/CYC_A","SAM/CYC_D",
"NUM_OF_CYC","PRIM_VAL", "yyy"xxx,xx,xx,x.xxxx,x.xxxx,xxxxx,"YES","yyyy"
"IARMS(A)","IBRMS(A)","ICRMS(A)","SDIA(A)","SDIB(A)","SDIC(A)","SDIAREF(A)",
"SDIBREF(A)","SDICREF(A)","dA(A)","dB(A)","dC(A)","T7CNTA","T7CNTB","T7CNTC",
"T8CNTA","T8CNTB","T8CNTC","TRIG","* * * * * * NTUNE_A NTUNE_B NTUNE_C * * *
DL2CLRA DL2CLRB DL2CLRC ITUNE_A ITUNE_B ITUNE_C DIA_DIS DIB_DIS DIC_DIS
DVA_DIS DVB_DIS DVC_DIS HIA2_A HIA2_B HIA2_C FRZCLRA FRZCLRB FRZCLRC DUPA
DUPB DUPC HIF2_A HIF2_B HIF2_C LRA LRB LRC DDNA DDNB DDNC 3PH_CLR LR3 HIFER
HIFMODE 3PH_EVE HIFREC","yyyy"
xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,
xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xx,xx,xx,xx,xx,xx,
    ,"000000000000","yyyy"
.
.
.
xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,
xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xxxxx,xx,xx,xx,xx,xx,xx,
    ,"000000000000","yyyy"


yyyy shall be the 4-byte ASCII checksum.
xxxx shall be the associated analog values as specified in HIF Event Reporting SRS
0000 shall be the hexadecimal representation of the Relay Word bit.
```

High-Impedance Fault COMTRADE File Format Reports

The SEL-651R-2 stores high-impedance fault oscillography in binary format and uses COMTRADE file types to output these data:

➤ .HDR–header file

➤ .CFG–configuration file

➤ .DAT–data file

The .HDR file contains summary information about the event in ASCII format. The .CFG file is an ASCII configuration file that describes the layout of the .DAT file. The .DAT file is in binary format and contains the values for each input channel for each sample in the record. These data conform to the IEEE C37.111-1999 COMTRADE standard.

.HDR File

The .HDR file contains the output of the HIF summary command (**SUM HIF**) and settings relevant to the high-impedance fault detection logic as illustrated in *Figure 12.17*.

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High-Impedance Fault (HIF) Event Reporting

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```
=>>SUM HIF <Enter>

FEEDER 1                             Date: 08/03/2012  Time: 08:52:15.854
STATION A                            Time Source: external

Event Number = 10000
Event: HIF Fault                     HIF Phase: A,B
Downed Conductor: NO                 Freq: 59.99
Breaker: CLOSED

Pre-trigger (A):
IARMS      IBRMS      ICRMS
312.0      238.0      282.0

Post-trigger (A):
312.0      245.0      281.0

Pre-trigger (A):
SDIA       SDIB       SDIC
236.5      203.5      211.5

Post-trigger (A):
247.0      217.0      224.0

CTR,"1000.0"
HIFLER,"2"
```

Figure 12.17   Sample HIF COMTRADE .HDR Header File

.CFG File

The .CFG file contains data that are used to reconstruct the captured high-impedance fault data during the event report (see *Figure 12.18*). A <CR><LF> follows each line.

```
<RID>, <FID>, 1999
##,##A,##D ──────────────────────────────────── Total Channels, Analog, Digital

1,IARMS,A,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
2,IBRMS,B,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
3,ICRMS,C,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
4,SDIA,A,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
5,SDIB,B,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
6,SDIC,C,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
7,SDIAREF,A,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
8,SDIBREF,B,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
9,SDICREF,C,,A,<scale factor>,0.0,0,-32767,32767,<CTR>,1,P
10,dA,A,,A,1.000000,0.0,0,-32767,32767,<CTR>,1,P      Analog Channel Data
11,dB,B,,A,1.000000,0.0,0,-32767,32767,<CTR>,1,P
12,dC,C,,A,1.000000,0.0,0,-32767,32767,<CTR>,1,P
13,T7CNTA,A,,,1,0,0,-32767,32767,1,1,P
14,T7CNTB,B,,,1,0,0,-32767,32767,1,1,P
15,T7CNTC,C,,,1,0,0,-32767,32767,1,1,P
16,T8CNTA,A,,,1,0,0,-32767,32767,1,1,P
17,T8CNTB,B,,,1,0,0,-32767,32767,1,1,P
17,T8CNTB,B,,,1,0,0,-32767,32767,1,1,P

1,<RWBIT>,,,0
...                                               Digital (Status) Channel Data

##,<RWBIT>,,,0
NFREQ
0
0, <last sample number>
dd/mm/yyyy,hh:mm:ss.ssssss ──────────────────── First Data Point
dd/mm/yyyy,hh:mm:ss.ssssss ──────────────────── Trigger Point
BINARY
1
```

Figure 12.18   Sample HIF COMTRADE .CFG Configuration File Data

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The configuration file has the following format:

➤ Station name, device identification, COMTRADE standard year

➤ Number and type of channels

➤ Channel name units and conversion factors

➤ HIF digital relay word bit names

➤ Nominal frequency

➤ Number of samples

➤ Date and times of first data point and event trigger

The .CFG file references analog quantities that are particular to High-impedance fault detection. See *High-Impedance Fault Compressed Event Report on page 12.52* for description of HIF analog and digital values.

.DAT File

The .DAT file follows the COMTRADE binary standard. The format of the binary data files is sample number, time stamp, data value for each analog channel, and digital channel status data for each sample in the file. There are no data separators or carriage return/line feed characters in the binary file. The sequential position of the data in the binary file determines the data translation. Refer to the *IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems, IEEE C37.111-1999* for more information. Many programs read the binary COMTRADE files. These programs include Analytic Assistant.

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Section 13

Testing and Troubleshooting

Introduction

This section contains guidelines for determining and establishing test routines for the SEL-651R-2 Recloser Control. Follow the standard practices of your company in choosing testing philosophies, methods, and tools. The recloser control incorporates self-tests to help you diagnose potential difficulties should these occur. *Recloser Control Troubleshooting on page 13.11* contains a quick-reference table for common recloser control operation problems.

Topics, tests, and troubleshooting procedures presented in this section include the following:

➤ *Testing Philosophy on page 13.1*

➤ *Self-Tests on page 13.7*

➤ *Recloser Control Troubleshooting on page 13.11*

➤ *Recloser Control Calibration on page 13.15*

➤ *Technical Support on page 13.15*

Testing Philosophy

Recloser control testing may be divided into three categories: acceptance, commissioning, and maintenance testing. The categories are differentiated by when they take place in the life cycle of the recloser control as well as by the test complexity.

The paragraphs below describe when to perform each type of test, the goals of testing at that time, and the recloser control functions that you need to test at each point. This information is intended as a guideline for testing SEL recloser controls.

Acceptance Testing

When: When qualifying a recloser control model to be used on the utility system.

Goals:

1. Ensure that the recloser control meets published critical performance specifications such as operating speed and element accuracy.

2. Ensure that the recloser control meets the requirements of the intended application.

3. Gain familiarity with recloser control settings and capabilities.

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What to test: All protection elements and logic functions critical to the intended application.

SEL performs detailed acceptance testing on all new recloser control models and versions. We are certain that the recloser controls we ship meet their published specifications. It is important to perform acceptance testing on a recloser control if you are unfamiliar with its operating theory, protection scheme logic, or settings. This helps ensure the accuracy and correctness of the recloser control settings when you issue them.

Commissioning Testing

When: When installing a new protection system.

Goals:

1. Ensure that all system ac and dc connections are correct.

2. Ensure that the recloser control functions as intended using your settings.

3. Ensure that all auxiliary equipment operates as intended.

What to test: All connected or monitored inputs and outputs, polarity and phase rotation of ac connections, simple check of protection elements.

SEL performs a complete functional check and calibration of each recloser control before it is shipped. This helps ensure that you receive a recloser control that operates correctly and accurately. Commissioning tests should verify that the recloser control is properly connected to the power system and all auxiliary equipment. Verify control signal inputs and outputs. Check breaker auxiliary inputs, SCADA control inputs, and monitoring outputs. Use an ac connection check to verify that the recloser control current and voltage inputs are of the proper magnitude and phase rotation.

Brief fault tests ensure that the recloser control settings are correct. It is not necessary to test every recloser control element, timer, and function in these tests.

At commissioning time:

1. Use the recloser control **METER** command to verify the ac current and voltage magnitude and phase rotation.

2. Use the **PULSE** command to verify recloser control output contact operation.

3. Use the **TARGET** command to verify optoisolated input operation.

Maintenance Testing

When: At regularly scheduled intervals or when there is an indication of a problem with the recloser control or system.

Goals:

1. Ensure that the recloser control is measuring ac quantities accurately.

2. Ensure that scheme logic and protection elements are functioning correctly.

3. Ensure that auxiliary equipment is functioning correctly.

What to test: Anything not shown to have operated during an actual fault within the past maintenance interval.

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SEL recloser controls use extensive self-testing capabilities and feature detailed metering and event reporting functions that lower dependence on routine maintenance testing.

1. Use the SEL recloser control reporting functions as maintenance tools.

    Periodically verify that the recloser control is making correct and accurate current and voltage measurements by comparing the recloser control METER output to other meter readings on that line.

2. Review recloser control event reports in detail after each fault.

    Using the event report current, voltage, and recloser control element data, you can determine that the recloser control protection elements are operating properly.

    Using the event report input and output data, you can determine that the recloser control is asserting outputs at the correct instants and that auxiliary equipment is operating properly.

3. At the end of your maintenance interval, the only items that need testing are those that have not operated during the maintenance interval.

The basis of this testing philosophy is simple: If the recloser control is correctly set and connected, is measuring properly, and no self-test has failed, there is no reason to test it further.

Each time a fault occurs, the protection system is tested. Use event report data to determine areas requiring attention. Slow breaker auxiliary contact operations and increasing or varying breaker operating time can be detected through detailed analysis of recloser control event reports.

Because SEL recloser controls are microprocessor based, their operating characteristics do not change over time. Time-overcurrent operating times are affected only by the recloser control settings and applied signals. It is not necessary to verify operating characteristics as part of maintenance checks.

At SEL, we recommend that maintenance tests on SEL recloser controls be limited under the guidelines provided above. The time saved may be spent analyzing event data and thoroughly testing those systems that require more attention.

Testing Methods and Tools

Test Features

The following features assist you during recloser control testing.

METER Command. The **METER** command shows the ac currents and voltages (magnitude and phase angle) presented to the recloser control in primary values. In addition, the command shows power system frequency. Compare these quantities against other devices of known accuracy. The **METER** command is available at the serial ports and front-panel display (see *Section 10: Communications* and *Section 11: Front-Panel Operations)*.

EVENT Command. The recloser control generates a 15-, 30-, or 60-cycle event report in response to faults or disturbances. Each report contains current and voltage information, recloser control element states, and input/output contact information. If you question the recloser control

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response or your test method, use the event report for more information. The **EVENT** command is available at the serial ports (see *Section 12: Analyzing Events*).

SER Command. The recloser control provides a Sequential Events Recorder (SER) event report that time-tags changes in recloser control element and input/output contact states. The SER provides a convenient means to verify the pickup/dropout of any element in the recloser control. The **SER** command is available at the serial ports. (see *Section 12: Analyzing Events*).

TARGET Command. Use the **TARGET** command to view the state of recloser control inputs, recloser control outputs, and recloser control elements individually during a test. The **TARGET** command is available at the serial ports and the front panel (see *Section 10: Communications* and *Section 11: Front-Panel Operations)*.

PULSE Command. Use the **PULSE** command to test the contact output circuits. The **PULSE** command is available at the serial ports and the front panel (see *Section 10: Communications* and *Section 11: Front-Panel Operations*).

Test Methods

Test the pickup and dropout of recloser control elements by using one of the three following methods:

➤ Target command indication

➤ Output contact closure

➤ Sequential Events Recorder (SER)

The examples below show the settings necessary to route the phase time-overcurrent element 51PT to the output contacts and the SER. The 51PT element, like many in the SEL-651R-2, is controlled by enable settings and/or torque-control SELOGIC control equations. To enable the 51PT element, set the E51P enable setting and 51PTC torque-control settings to the following:

➤ E51P := 1 (via the **SET** command)

➤ 51PTC := 1 (set directly to logical 1, via the **SET L** command)

Testing Via TARGET Commands

Display the state of recloser control elements, inputs, and outputs by using the front-panel or serial port **TAR** commands. Use this method to verify the pickup settings of protection elements.

Testing With the Front-Panel TAR Command

You can use the front-panel display and navigation pushbuttons to check Relay Word bit elements. See *Section 11: Front-Panel Operations* for more information on using the recloser control front panel.

Display the MAIN menu. If the recloser control LCD is in the Rotating Display, press the **ENT** pushbutton to display the MAIN menu as shown in *Figure 13.1*.

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Main Menu

```
MAIN
Meter
Events
Reclosing
Monitor
Targets
Control
Set/Show
Status
Reset Access Lvl
```

Figure 13.1   MAIN Menu

Select the TARGETS menu item from the MAIN menu and then use the cursor keys to navigate to the Relay Word row that contains the element you wish to view as shown by the Targets Menu in *Figure 13.2*. You may view the entire row at once or you can select the row by pressing the **ENT** pushbutton to view more detailed information about each Relay Word bit in the row selected as shown by the Targets Display in the figure.

Targets Menu   Targets Display

```
TARGETS                    Column 1=x
Row 0=xxxxxxxx             Column 2=x
Row 1=xxxxxxxx                 ⋮
Row 2=xxxxxxxx             Column 8=x
Row 3=xxxxxxxx
    ⋮
```
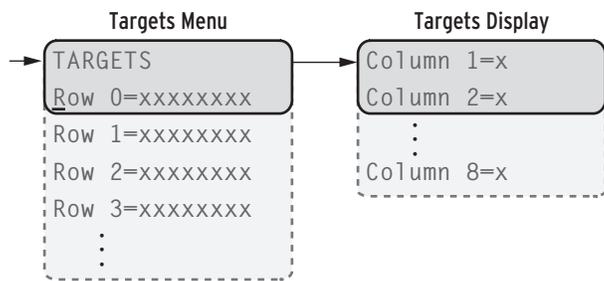
Figure 13.2   TARGETS Menu and TARGETS Display

See *Table F.1* for the correspondence between the Relay Word elements and the **TAR** command.

Testing With the Serial Port TAR Command

To view the 51PT element status from the serial port, issue the **TAR 51PT** command. The recloser control will display the state of all elements in the Relay Word row containing the 51PT element.

Review **TAR** command descriptions in *Section 10: Communications* and *Section 11: Front-Panel Operations* for further details on displaying element status via the **TAR** commands.

Testing Via Output Contacts

You can set the recloser control to operate an output contact for testing a single element. Use the **SET L** command (SELOGIC control equations) to set an output contact (e.g., OUT101–OUT108) to the element under test. The available elements are the Relay Word bits referenced in *Table F.1*.

Use this method especially for time testing time-overcurrent elements. For example, to test the phase time-overcurrent element 51PT via output contact OUT104, make the following setting:

OUT104 := 51PT

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Time-overcurrent curve and time-dial information can be found in *Section 9: Settings*.

Do not forget to reenter the correct recloser control settings when you are finished testing and ready to place the recloser control in service.

Testing Via Sequential Events Recorder

You can set the recloser control to generate an entry in the Sequential Events Recorder (SER) for testing recloser control elements. Use the **SET R** command to include the element(s) under test in any of the SER trigger lists (SER1–SER3) (see *Section 12: Analyzing Events*).

To test the phase time-overcurrent element 51PT with the SER, make the following setting:

> SER1 := 51P 51PT

Element 51P asserts when phase current is above the pickup of the phase time-overcurrent element. Element 51PT asserts when the phase time-overcurrent element times out. The assertion and deassertion of these elements is time-stamped in the SER report. Use this method to verify timing associated with time-overcurrent elements, reclosing relay operation, etc.

Do not forget to reenter the correct recloser control settings when you are ready to place the recloser control in service.

Low-Level Test Interface

NOTE: The SEL-4000 Relay Test System, which includes the SEL Adaptive Multichannel Source, appropriate cables, and PC software, is specifically designed for use with the low-level test interface.

INTENDED USE FOR LOW-LEVEL TEST INTERFACE
The low-level test interface is intended for use in a laboratory or office setting. For example the interface may be used for qualifying relay features and settings during acceptance and/or validation testing. The test interface is not intended to be used in the field for commissioning or maintenance testing.

⚠**CAUTION**
The relay contains devices sensitive to Electrostatic Discharge (ESD). When working on the relay with the front panel removed, work surfaces and personnel must be properly grounded or equipment damage may result.

⚠**CAUTION**
Never apply voltage signals greater than 9 V peak-peak to the low-level test interface (**J14**) or equipment damage may result.

The SEL-651R-2 has a low-level test interface between the input module and the processing module. You may test the relay in either of two ways:

> ➤ By applying ac current signals to the relay inputs, or

> ➤ By applying low magnitude ac voltage signals to the low-level test interface. See *Relay Module Main Board Jumpers and Clock Battery on page 2.52* for information on accessing the relay main board and test interface.

Figure 2.48 shows the location of the processing module input connector (**J14**) for low-level test interface connections. The connector (**J8**) of the interface module is below connector **J14** and the output connector **J11** for the input module is below connector **J8**.

Figure 13.3 shows the low-level test interface (**J8** and **J14**) connector information. *Table 13.1* shows the output (**J11**) value of the input module (for a given input value into the relay rear panel). The processing module input (**J14**) has a maximum 9 V p-p voltage damage threshold. Remove the ribbon cable between the three modules to access the outputs (**J11**) of the input module and the inputs (**J14** and **J8**) to the processing module (relay main board) and interface module (recloser interface board), respectively.

You can test the relay-processing module (via input **J14**) by using signals from the SEL-4000 Relay Test System. The power supply for the relay main board is provided through the ribbon cable between **J8** and **J14**. An SEL-C737 cable is used to connect the relay to the SEL-4000 Relay Test System while maintaining the power supply connection. *Table 13.1* shows the resultant signal scale factor information for the calibrated input module. These scale factors are used in the SEL-5401 program, which is part of the SEL-4000.

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You can test the input module two different ways:

1. Measure the outputs from the input module with an accurate voltmeter (measure signal pin to GND pin) and compare the readings to accurate instruments in the relay input circuits.

2. Replace the ribbon cable, press the front-panel METER pushbutton, and compare the relay readings to other accurate instruments in the relay input circuits.
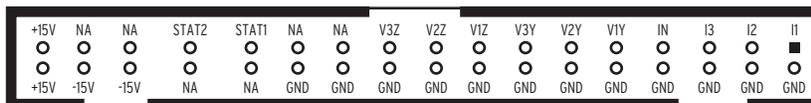
Figure 13.3   Low-Level Test Interface (J8 or J14) Connector

Table 13.1   Resultant Scale Factors for Input Module

Input Channels (Relay Rear Panel)	Input Channel Nominal Rating	Input Value	Corresponding J11 Output Value	Scale Factor (Input/ Output)
I1, I2, I3	1 A	1 A	101.2 mV	9.88 A/V
IN	0.2 A	200 mA	114.1 mV	1752.78 mA/V[a]
V1Y, V2Y, V3Y, V1Z, V2Z, V3Z	300 V	120 V_{LN}	1.196 V	100.34 V/V
V1Y, V2Y, V3Y, V1Z, V2Z, V3Z	8 V LEA	3.2 V_{LN}	1.196 V	2.68 V/V
V1Y, V2Y, V3Y, V1Z, V2Z, V3Z	120 V Lindsey SVMI LEA	120 V_{LN}	1.196 V	100.34 V/V
V1Y, V2Y, V3Y	37.09 V Eaton NOVA LEA	14.836 V_{LN}	1.196 V	12.40 V/V
V1Z, V2Z, V3Z	8.49 V Siemens LEA	3.396 V_{LN}	1.196 V	2.84 V/V

[a]   SEL-5401 neutral channel input currents must be entered in mA when using the given scale factor.

Scale factor calculation examples:

$$\frac{120 \text{ V}}{1.196 \text{ V}} = 100.34\left(\frac{V}{V}\right)$$

Equation 13.1

$$\frac{1 \text{ A}}{0.1012 \text{ V}} = 9.88\left(\frac{A}{V}\right)$$

Equation 13.2

Self-Tests

The SEL-651R-2 continuously runs many self-tests to detect out-of-tolerance conditions. These tests run at the same time as recloser control protection and automation logic, but do not degrade SEL-651R-2 performance.

Status Warning and Status Failure

The recloser control reports out-of-tolerance conditions as a status warning or a status failure. For conditions that do not compromise recloser control protection, yet are beyond expected limits, the recloser control issues a status warning and continues to operate. A severe out-of-tolerance condition causes the recloser control to declare a status failure and enter a protection-disabled

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state. During a protection-disabled state, the recloser control suspends protection element processing and trip/close logic processing and de-energizes all control outputs. When disabled, the `ENABLED` front-panel LED is not illuminated.

The recloser control signals a status warning by pulsing the HALARMP Relay Word bit (hardware alarm) to logical 1 for five seconds. In addition, the HALARMA Relay Word bit is pulsed for five seconds every minute once a diagnostic warning condition has occurred and until RST_HAL is asserted or the relay is power cycled. For a Status Failure, the recloser control latches the HALARML Relay Word bit at logical 1. The HALARM Relay Word bit is the logical OR of the HALARML and HALARMP Relay Word bits. To provide remote status indication, connect the b contact of OUT201 to your control system remote alarm input and program the output SELOGIC control equation to respond to NOT (SALARM OR HALARM).

If you repeatedly receive status warnings, check the recloser control operating conditions as soon as possible. Take preventive action early during the development of potential problems to avoid system failures. For any status failure, contact your Technical Service Center or the SEL factory immediately (see *Technical Support on page 13.15*).

The recloser control generates an automatic status report at the serial ports for a self-test status failure if you set Port setting AUTO := Y. The recloser control issues a status message with a format identical to the **STATUS** command output.

For certain failures, the relay automatically restarts as many as three times within 24 hours. In many instances, this will correct the failure. A "diagnostic restart" entry is recorded in the Sequential Events Recorder (SER), but the automatic restart may occur before Relay Word bits HALARM and HALARML are recorded in the SER and before failure messages are displayed.

Use the serial port **STATUS** and **CSTATUS** commands, the ACSELERATOR QuickSet SEL-5030 Software **HMI Status** button, the **Self-Test Status Report** from the left pane of the web server, or the front-panel `STATUS` menu to display status warnings and status failures. See *Section 10: Communications* for more information on automatic status notifications and on viewing recloser control status.

Firmware Version Number

At the top of each status report the recloser control displays the present firmware version number that identifies the software program that controls recloser control functions. The firmware version is the four-place designator immediately following the recloser control model number (the first characters in the firmware identification string). The first character in the four-place firmware version number is "R" (representing "Release"). SEL numbers subsequent firmware releases sequentially; the next revision following R101 is R102. See *Appendix A: Firmware and Manual Versions* for firmware version information.

Status

Use the serial port **STATUS** command, select the `STATUS` menu item from the `MAIN` menu on the front-panel HMI, or choose the **Self-Test Status Report** from the left pane of the web server to view the self-test status report. An

example status report is shown in *STA Command (Relay Self-Test Status) on page 10.70*. Use *Table 13.2* and *Table 13.3* to interpret the self-test results and measurements.

Table 13.2   Status Report Results (Sheet 1 of 3)

Self-Test	Condition	Description	Normal Range	Hardware Alarm Relay Word Bit(s)[a]	Protection Disabled on Failure	Port Auto Message	Front-Panel Message	Corrective Action
Channel Offsets I1, I2, I3, V1Y, V2Y, V3Y, V1Z, V2Z, V3Z	Warning	DC offset on A/D channel outside of normal range	< 30 mV for current channels and < 50 mV for voltage channels other than 8 Vac LEA; < 175 mV for 8 Vac LEA voltage channels	HALARMP, HALARMA	No	Yes		
MOF (Master Offset)	Warning	DC offset on A/D ground channel outside normal range	< 10 mV	HALARMP, HALARMA	No	Yes		
MOF (Master Offset)	Failure	DC offset on A/D ground channel outside normal range	< 30 mV	HALARML	Yes	Yes	STATUS FAIL A/D FAILURE	
+5V_PS	Warning	+5 V Power Supply outside warning range	4.71 to 5.29 V	HALARMP, HALARMA	No	Yes		
+5V_PS	Failure	+5 V Power Supply outside failure range	4.31 to 5.73 V	HALARML	Yes	Yes	STATUS FAIL +5V_PS FAIL	
+5V_REG	Warning	5 V Regulated Power Supply outside warning range	4.76 to 5.24 V	HALARMP, HALARMA	No	Yes		
+15V_PS	Warning	+15 V Power Supply outside warning range	13.96 to 16.06 V	HALARMP, HALARMA	No	Yes		
–15V_PS	Warning	–15 V Power Supply outside warning range	–13.96 to –16.06 V	HALARMP, HALARMA	No	Yes		
+12V_TC	Warning	12 V Trip/Close Control Supply outside warning range	11.12 to 12.91 V	HALARMP, HALARMA	No	Yes		
+12V_TC	Failure	12 V Trip/Close Control Supply outside failure range	< 8.96 V	HALARML	Yes	Yes	STATUS FAIL +12V_TC FAIL	
12VAUX	Warning	12 V Auxiliary Power Supply outside warning range	10.29 to 17.65 V	HALARMP, HALARMA	No	No		
TCCAP	Failure	Trip/Close Capacitor below coil voltage for one minute or more	Coil Voltage (see *Trip and Close Outputs on page 1.10*)	HALARML	No	Yes	STATUS FAIL TCCAP FAIL	
+5VA_PS	Warning	+5 V Analog Power Supply outside warning range	4.59 to 5.42 V	HALARMP, HALARMA	No	Yes		
–5VA_PS	Warning	–5 V Analog Power Supply outside warning range	–4.59 to –5.42 V	HALARMP, HALARMA	No	Yes		
Temperature	Warning	Relay Temperature outside normal range	–40° to 100°C	HALARMP, HALARMA	No	Yes		

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Table 13.2   Status Report Results (Sheet 2 of 3)

Self-Test	Condition	Description	Normal Range	Hardware Alarm Relay Word Bit(s)[a]	Protection Disabled on Failure	Port Auto Message	Front-Panel Message	Corrective Action
RTC	Warning	Unable to communicate with clock, or clock fails time keeping test		HALARMP, HALARMA	No	No		
HMI	Warning	HMI not connected or does not match relay part number		HALARMP, HALARMA	No	Yes		
RAM (External)	Failure	Failure of read/write test on system RAM		HALARML	Yes	No		
RAM (Internal or External)	Failure	Failure of internal or external RAM		HALARML	Yes	Yes	STATUS FAIL RAM FAILURE	Automatic restart
ROM (Operating System)	Failure	Operating System check fails		HALARML	Yes	Yes	CPU ERROR RELAY DISABLED	Automatic restart
A/D	Failure	Processing interval didn't complete in 1/4-cycle	< 1/4-cycle	HALARML	Yes	Yes	STATUS FAIL A/D FAILURE	
A/D	Failure	3 or more power supplies are outside of warning ranges		HALARML	Yes	Yes	STATUS FAIL A/D FAILURE	
Flash (Data Flash)	Failure	Failure of checksum test on relay settings		HALARML	Yes	Yes	STATUS FAIL FLASH FAILURE	
Flash (Code Flash)	Failure	Failure of checksum test on firmware code		HALARML	Yes	No		
FPGA	Failure	FPGA fails to program		HALARML	Yes	Yes		
FPGA	Failure	FPGA failure		HALARML	Yes	Yes	STATUS FAIL FPGA FAILURE	Automatic restart
ROM (EEPROM)	Failure	Failure to determine HALARML status on power-up		HALARML	Yes	Yes	STATUS FAIL EEPROM FAILURE	
ROM (EEPROM)	Warning	Failure of read/write to EEPROM		HALARMP, HALARMA	No	Yes		
INT Board	Failure	Invalid Interface Board ID		HALARML	Yes	Yes	STATUS FAIL INT_BRD FAIL	STA C
USB Board	Warning	Installed USB board does not match relay part number			No	No	STATUS WARNING USB WARNING	STA C
USB Board	Failure	USB communications board has failed			No	No	STATUS FAIL USB FAILURE	STA C
Communications Board	Warning	Installed communications card does not match relay Part Number			No	Yes		STA C

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Table 13.2   Status Report Results (Sheet 3 of 3)

Self-Test	Condition	Description	Normal Range	Hardware Alarm Relay Word Bit(s)[a]	Protection Disabled on Failure	Port Auto Message	Front-Panel Message	Corrective Action
Communications Board	Failure	Communications board has failed			No	Yes	`STATUS FAIL COM FAILURE`	STA C
Exception	Failure	CPU Error		HALARML	Yes	Yes	`CPU ERROR RELAY DISABLED`	Automatic restart

[a] See Status Warning and Status Failure on page 13.7 for an explanation.

Table 13.3   Status Report Measurements

INPBV	This value is the Input Power Bus Voltage.
12VAUX	This value is the 12 V Auxiliary Bus Voltage.
CMODE	Battery State—This value is the charger mode (see *Battery Status on page 8.43* for a list and description of modes).
VBAT	This value is the battery voltage.
IBAT	This value is the battery charging or discharging current. If the battery is discharging it shall be shown with a preceding minus sign.
TCCAPV	This value is the Trip/Close Capacitor Voltage.

Recloser Control Troubleshooting

Inspection Procedure

Complete the following procedure before disturbing the recloser control. After you finish the inspection, proceed to the *Troubleshooting Procedure*.

Step 1.   Measure and record the power supply voltage at the power input terminals.

Step 2.   Check to see that the power is on. Do not turn the recloser control off.

Step 3.   Measure and record the voltage at all control inputs.

Step 4.   Measure and record the state of all output relays.

Step 5.   Inspect the serial communications ports cabling to be sure that a communications device is connected to at least one communications port.

Troubleshooting Procedure

Troubleshooting procedures for common problems are listed in *Table 13.4*. The table lists each symptom, possible causes, and corresponding diagnoses/solutions. Related SEL-651R-2 commands are listed in bold capitals. See *Section 10: Communications* for details on SEL-651R-2 commands and *Section 9: Settings* for details on recloser control settings.

Table 13.4   Troubleshooting Procedures (Sheet 1 of 5)

Symptom/Possible Cause	Diagnosis/Solution
Dark Front Panel	
Power is off and recloser control has shut down to conserve the battery.	Restore power or press **WAKE UP**.
Input power is not present.	Verify that power is present at the rear-panel terminal strip.

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Table 13.4   Troubleshooting Procedures (Sheet 2 of 5)

Symptom/Possible Cause	Diagnosis/Solution
Blown power supply fuse.	Replace the fuse (see *Battery and Fuse Replacement on page 2.57*).
Poor contrast adjustment.	Press and hold **ESC** for two seconds. Press the **Up Arrow** and **Down Arrow** pushbuttons to adjust contrast.
Status Failure Notice on Front Panel	
Self-test failure.	Contact the SEL factory or your Technical Service Center. The OUT201 recloser control b contacts will be closed if "NOT HALARM" is programmed to OUT201.
Alarm Output Asserts	
Power is off.	Restore power or press **WAKE UP**.
Blown power supply fuse.	Replace the fuse (see *Battery and Fuse Replacement on page 2.57*).
Power supply failure.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
Main board or interface board failure.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
Other self-test failure.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
System Does Not Respond to Commands From Device Connected to Communications Port	
No communication.	Confirm cable connections and types. If OK, type **<Ctrl+X>**, then **<Enter>**. This resets the terminal program.
Communications device is not connected to the system.	Connect a communications device.
Incorrect data speed (baud rate) or other communications parameters.	Configure your terminal port parameters to the particular recloser control port settings. Use the front panel to check port settings (see *SET/SHOW Menu on page 11.12*).
Incorrect communications cables.	Use SEL communications cables, or cables you build according to SEL specifications (see *Port Connectors and Communications Cables on page 10.9*).
Communications cabling error.	Check cable connections.
Handshake line conflict; system is attempting to transmit information, but cannot do so.	Check communications cabling. Use SEL communications cables, or cables you build according to SEL specifications (see *Section 10: Communications*).
System is in the XOFF state, halting communications.	Type **<Ctrl+Q>** to put the system in the XON state.
The relay communications port is disabled (setting EPORT := N).	Change the setting by entering the **SET P** *n* command from another communications interface (serial port, USB, or Telnet session) or by using the front-panel interface. When Port F is disabled, the USB is also disabled and cannot be used to change the EPORT setting (see *Port 5 Settings on page SET.70*).
Relay Does Not Respond to Commands From Device Connected to USB Port	
The USB driver is not installed on the PC, or an incorrect driver was installed.	Install the correct USB driver (see *Establishing Communications Through Use of the USB Port on page 10.2*)
The USB cable was disconnected while a PC application was communicating with the relay.	Reconnect the USB cable.
The relay USB port is disabled (Port F setting EPORT := N).	Change the setting by entering the **SET P F** command from another communications interface (serial port or Telnet session) or by using the front-panel interface (see *Port Enable Settings (SET P n Command) on page 9.60*).
The USB cable is faulty or is not USB 2.0 compliant.	Install a proper USB 2.0 compliant cable. Use an SEL-C664 or equivalent cable.

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Table 13.4   Troubleshooting Procedures (Sheet 3 of 5)

Symptom/Possible Cause	Diagnosis/Solution
The relay USB Board has failed. Use these steps to attempt to correct the problem:	a. Check USB Board status by entering the **STATUS** command from a serial port or Ethernet connection. b. If STATUS is FAIL, issue a **STA C** command to attempt to clear the condition. c. If STATUS is OK, connect the USB cable between the PC and the relay and use Windows Device Manager to verify that the Schweitzer Engineering Laboratories Fast CDC USB device appears under Ports. d. Use the Task Manager (if necessary) to confirm that any PC application that was using the port has terminated. If any such application remains running, close the application. e. Disconnect the USB cable. Use Windows Device Manager to verify that the Schweitzer Engineering Laboratories Fast CDC USB device does not appear under Ports. Reconnect the USB cable and verify that Schweitzer Engineering Laboratories Fast CDC USB device appears under Ports. f. If these steps fail to correct the problem, contact SEL for further assistance.
Relay Does Not Respond Via Telnet or HTTP (Web Server) Interface	
Communications device is not connected to the relay.	Connect a communications device to the relay. See *Section 10: Communications* for details on connecting and configuring communications.
The relay Ethernet port is disabled (setting EPORT = N).	Change the setting by entering the **SET P 5** command from another communications interface (serial port or USB session) or by using the front-panel interface (see *Port Enable Settings (SET P n Command) on page 9.60*).
Relay or communications device is not properly configured for Ethernet connection.	Check the relay settings for the port, including ETELNET or EHTTP and associated settings.
Maximum number of sessions is exceeded.	See *Session Limits on page 10.14*.
Firmware upgrade option is not available on the web server	Check HTTPACC setting.
Terminal Displays Meaningless Characters	
Data speed (baud rate) is set incorrectly.	Check the terminal parameters configuration (see *Establishing Communications Using a Serial Port on page 10.1*).
Terminal emulation is not optimal.	Try other terminal types, including VT-100 and VT-52 terminal emulations.
System Does Not Respond to Faults	
Recloser control is set improperly.	Review the recloser control settings (see *Section 9: Settings*).
Improper test settings.	Restore operating settings.
PT or CT connection wiring error.	Confirm PT and CT wiring.
Input voltages and currents phasing, and rotation errors.	Use recloser control metering. Use the **TRI** event trigger command and examine the generated event report.
The analog input (flat multi-pin ribbon) cable between the input module board and the main board is loose or defective.	Reseat both ends of the analog input cable, observing proper ESD precautions.
Check the recloser control self-test status.	Take preventive action as directed by recloser control Status Warning and Status Failure information.
Tripping Output Remains Closed Following a Fault	
Auxiliary contact control inputs are improperly wired.	Check circuit breaker auxiliary contacts wiring.
Recloser control outputs have burned closed.	Remove recloser control power. Remove the control output connection. Check continuity; a contacts will be open and b contacts will be closed. Contact the SEL factory or your Technical Service Center if continuity checks fail.
I/O interface board failure.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.

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Table 13.4 Troubleshooting Procedures (Sheet 4 of 5)

Symptom/Possible Cause	Diagnosis/Solution
Power Supply Voltage Status Warning	
Power supply voltage(s) are out-of-tolerance.	Log the Status Warning. If repeated warnings occur, take preventive action.
A/D converter failure.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
Power Supply Voltage Status Failure	
Power supply voltage(s) are out-of-tolerance.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
A/D converter failure.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
Trip/Close Capacitor (TCCAP) Failure	
Trip/Close capacitors are below nominal voltage or the J205 cable is disconnected.	LCD displays STATUS FAIL TCCAP FAILURE screen, or TCCAPV status is reported as a failure state. Check **J205** cable connection. If cable is loose or disconnected, perform the following: a. Reattach the **J205** cable. b. Issue a **STA C** command from a serial port or Ethernet connection. c. Wait two minutes. d. Issue a **STA** command and check for a failure condition. If the error returns or the cable was securely connected, contact the SEL factory or your Technical Service Center.
A/D OFFSET WARN Status Warning	
Loose ribbon cable between the input module board and the main board.	Reseat both ends of the analog input cable.
A/D converter drift.	Log the Status Warning. If repeated warnings occur, contact the SEL factory or your Technical Service Center.
Master offset drift.	LCD displays STATUS FAILURE screen. Contact the SEL factory or your Technical Service Center.
Battery Problem LED Illuminated	
Discharge test failure caused by an on-load battery voltage measurement < 10.5 V or a measurement of < 11 V after 10 seconds on-load. Open-circuit measurement must be > 11.58 V to begin test.	Replace failed battery.
Battery voltage measurement < 5 V.	Battery is either deeply discharged or failed. Replace battery.
Excessive current draw for excessive time during float charge mode.	Battery has probably failed. Test battery and replace if failed.
Meter Command Does Not Respond as Expected	
Sequence current or voltage magnitudes are incorrect.	Global settings NFREQ or PHROT not set correctly.
Current phase polarity or connection compensation is incorrect.	Global settings IPCONN or CTPOL not set correctly.
Voltage connection compensation is incorrect.	Global settings VYCONN, VZCONN, VSELECT or FSELECT not set correctly.
Current or voltage magnitudes are incorrect.	Group settings CTR, CTRN, PTRY or PTRZ not set correctly.
Current or voltage angles or power magnitudes are incorrect.	Recloser control analog inputs not connected correctly.
LEA voltage magnitudes are incorrect.	Global settings VxYRCF or VxZRCF (where x = 1, 2, 3) not set correctly. The neutral input on the LEA channel is not properly grounded.

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Recloser Control Calibration

Table 13.4   Troubleshooting Procedures (Sheet 5 of 5)

Symptom/Possible Cause	Diagnosis/Solution
Relay Time Stamp Entries Appear Out of Order for Fast Changes in SER	
Simple Network Time Protocol (SNTP) is changing the system time too frequently, and that time source is not sufficiently accurate.	Consider changes to the SNTP configuration. See *Section 10: Communications* for more information on SNTP.
DNP is updating the system time too frequently, and that time source is not sufficiently accurate.	Consider changes to the TIMERQ and TIMERQ*n* settings (see *Appendix E: DNP3 Communications*).

Recloser Control Calibration

The SEL-651R-2 is factory-calibrated. If you suspect that the control is out of calibration, please contact the factory.

Technical Support

We appreciate your interest in SEL products and services. If you have questions or comments, please contact us at:

Schweitzer Engineering Laboratories, Inc.
2350 NE Hopkins Court
Pullman, WA 99163-5603 U.S.A.
Phone: +1.509.338.3838
Fax: +1.509.332.7990
Internet: selinc.com/support
Email: info@selinc.com

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Appendix A
Firmware and Manual Versions

Firmware

Determining the Firmware Version in Your Relay

To determine the firmware version, view the status report by using the serial port **STATUS** command or the front panel **STATUS** pushbutton. The status report displays the Firmware Identification (FID) number.

The firmware version will be either a standard release or a point release. A standard release adds new functionality to the firmware beyond the specifications of the existing version. A point release is reserved for modifying firmware functionality to conform to the specifications of the existing version.

A standard firmware release is identified by a change in the R-number of the device FID number.

Existing firmware:

FID=SEL-651R-2-**R100**-Vx-Zxxxxxx-Dxxxxxxxx

Standard release firmware:

FID=SEL-651R-2-**R101**-Vx-Zxxxxxx-Dxxxxxxxx

A point release is identified by a change in the V-number of the device FID number.

Existing firmware:

FID=SEL-651R-2-Rxxx-**V0**-Zxxxxxx-Dxxxxxxxx

Point release firmware:

FID=SEL-651R-2-Rxxx-**V1**-Zxxxxxx-Dxxxxxxxx

The release date is after the D. For example, the following is firmware version number R100, release date December 10, 2003.

FID=SEL-651R-2-R100-Vx-Zxxxxxx-**D20031210**

Revision History

Table A.1 lists the firmware versions, revision descriptions, and corresponding instruction manual date codes.

Table A.1   Firmware Revision History (Sheet 1 of 5)

Firmware Identification (FID) Number	Summary of Revisions	Manual Date Code
SEL-651R-2-R407-V0-Z007003-D20180131	➤ Added support for the Eaton NOVA NX-T Recloser on the Multi-Recloser Interface. ➤ Made Voltage Phase Angle Correction settings available for 8 Vac LEA. ➤ Resolved an issue where ASCII commands could report the time source as internal when an external time source is connected. ➤ ASCII commands now report SNTP as an external time source.	20180131

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Firmware

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Table A.1   Firmware Revision History (Sheet 2 of 5)

Firmware Identification (FID) Number	Summary of Revisions	Manual Date Code
	➤ Operation counters and Breaker Wear quantities are now available for Load Profile and SELOGIC expressions. ➤ SELOGIC counters are now available for Load Profile and Display points. ➤ Added feature to allow anonymous TCP connection from DNP masters when DNPIP*x* is set to 0.0.0.0. ➤ Modified the 12V_TC and +5V_PS self-test diagnostic failure conditions to disable protection. ➤ Added a Trip/Close Capacitor (TCCAP) self-test diagnostic failure condition.	
SEL-651R-2-R406-V1-Z006003-D20170818	Includes all the functions of SEL-651R-2-R406-V0-Z006003-D20160810 with the following addition: ➤ Resolved an issue where certain Ethernet traffic could cause diagnostic restarts.	20170818
SEL-651R-2-R406-V0-Z006003-D20160810	➤ Changed the lower end of the phase and negative-sequence time-overcurrent element pickup setting (51PJP, 51PKP, 51AJP, 51AKP, 51BJP, 51BKP, 51CJP, 51CKP, 51QJP, and 51QKP) ranges from 0.10 to 0.05 A, secondary. ➤ Made FWVNUM (Relay Firmware Version Number) available via DNP and Modbus protocols. ➤ Added setting option AUTO2 for directional elements enable setting E32. ➤ Added Relay Word bit DISTST, indicating that a battery discharge test is in progress. ➤ Made Group settings RID (Relay Identifier) and TID (Terminal Identifier) available for Display Points. ➤ Group setting EHIF := N no longer prevents existing high-impedance fault event reports from being accessed. ➤ Virtual bits now reset when a new CID file is sent to the control. ➤ Changed default MMS inactivity time-out from 2 minutes to 15 minutes.	20160810
SEL-651R-2-R405-V3-Z005003-D20170818	Includes all the functions of SEL-651R-2-R405-V2-Z005003-D20150722 with the following addition: ➤ Resolved an issue where certain Ethernet traffic could cause diagnostic restarts.	20170818
SEL-651R-2-R405-V2-Z005003-D20150722	Includes all the functions of SEL-651R-2-R405-V1-Z005003-D20150709 with the following addition: ➤ Updated field upgrade process for R405-V1.	20150722
SEL-651R-2-R405-V1-Z005003-D20150709	Includes all the functions of SEL-651R-2-R405-V0-Z005003-D20140306 with the following addition: ➤ Resolved an issue where latch bits may be restored to an incorrect state after power is restored to the control or the control is restarted. **Note:** Firmware version R405-V1 is not intended for field upgrades.	20150709

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Table A.1   Firmware Revision History (Sheet 3 of 5)

Firmware Identification (FID) Number	Summary of Revisions	Manual Date Code
SEL-651R-2-R405-V0-Z005003-D20140306	➤ Added neutral time-overcurrent elements (51N1 and 51N2). ➤ Added rate-of-change-of-frequency (81R) elements. ➤ Modified setting range of TCLOSD setting to 0–50 cyc when NFREQ = 50 Hz. ➤ Added Z0MTA setting for zero-sequence voltage-polarized directional element. ➤ Increased the resolution of energy metering to three decimal places. ➤ Increased number of math variables from 32 to 64. ➤ Added default setting to detect and display control cable disconnection and yellow operating handle status for multi-recloser interface. ➤ Added MAXACC = 0 setting to restrict access to ports while allowing SEL Fast Protocols to function and allow **SNS**, **BNA**, and **DNA** commands at Access Level 0. ➤ Revised CFG.txt file to include settings checksum. ➤ Added COMTRADE events directory for MMS file transfer. ➤ Made events (COMTRADE file format and Compressed ASCII) and reports (Metering, History, LDP, SSI, diagnostics, etc.) available for Ymodem, FTP, and MMS file transfer. ➤ Added more statistics in **ETH** command response and ability to clear **ETH** command statistics. ➤ Added details of errors in settings transfer available in the ERR.txt file. ➤ Addressed formatting issue with front-panel display when internal trip counters (INTTA, INTTB, and INTTC) and VBAT are used in display points. ➤ Increased DNP binary outputs from 33 to 71. ➤ Added RSTDNPE SELOGIC control equation and DRSTDNPE DNP binary output to reset relay event queue. ➤ Modified DNP binary outputs so that they are no longer reported as offline when the binary output is present in the binary input map and the SER. ➤ Added MAXWEAR analog quantity; made MAXWEAR and math variables available for display points, DNP, Modbus, and IEC 61850. ➤ Added TOC pickup settings (51xxP_P) as primary quantities for DNP and display points. ➤ Added support for MMS authentication. ➤ Increased predefined MMS reports to 14 (7 buffered and 7 unbuffered) and simultaneous MMS sessions to 7. ➤ Added support to configure MMS inactivity time out. ➤ Added support for CID file transfer through MMS, and added EMMSFS setting to enable/disable MMS file services.	20140306

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Firmware

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Table A.1   Firmware Revision History (Sheet 4 of 5)

Firmware Identification (FID) Number	Summary of Revisions	Manual Date Code
	➤ Added feature to retain the existing valid CID file when an invalid CID file is sent. ➤ Modified virtual bits so that they no longer deassert temporarily after group or settings change. ➤ Added FLTRDRE and HIFRDRE logical nodes to indicate the presence of regular and high-impedance fault event reports. ➤ Changed dead band for IEC 61850 VBAT logical node from 100 to 5. ➤ Modified minimum negotiated MMS PDU size to 512 bytes. ➤ Modified maximum number of MMS variables that can be read or written to 256. **Note:** Firmware version R404 did not production release.	
SEL-651R-2-R403-V2-Z004002-D20170818	Includes all the functions of SEL-651R-2-R403-V1-Z004002-D20150722 with the following addition: ➤ Resolved an issue where certain Ethernet traffic could cause diagnostic restarts.	20170818
SEL-651R-2-R403-V1-Z004002-D20150722	Includes all the functions of SEL-651R-2-R403-V0-Z004002-D20150722 with the following addition: ➤ Resolved an issue where latch bits may be restored to an incorrect state after power is restored to the control or the control is restarted.	20150722
SEL-651R-2-R403-V0-Z004002-D20130624	➤ Extended range of ETIMEO and ETIMEOn port settings from 1–50 seconds to 1–120 seconds. ➤ Added RESPSZ port setting for limiting the packet size of DNP messages. ➤ Corrected handling of unrecognized Ethertype frames that can cause Ethernet to stop responding.	20130624
SEL-651R-2-R402-V1-Z003002-D20150722	Includes all the functions of SEL-651R-2-R402-V0-Z003002-D20150722 with the following addition: ➤ Resolved an issue where latch bits may be restored to an incorrect state after power is restored to the control or the control is restarted.	20150722
SEL-651R-2-R402-V0-Z003002-D20121219	➤ Added SEL Arc Sense Technology (AST) to detect high-impedance faults. ➤ Added ground overcurrent element (50G HIZ) to detect high-impedance faults. ➤ Added second harmonic elements for blocking sensitive overcurrent elements during transformer inrush. ➤ Added IEEE COMTRADE standard event reports. ➤ Extended the lower range of setting 79RSLD from 180 cycles to 0 cycles. ➤ Added COMTRADE event report to FTP and MMS file transfer. ➤ Global setting PMSTN now accepts upper and lower case characters. ➤ Reformatted relay web server. ➤ Relay now accepts IRIG-B signals with either even or odd parity. ➤ Corrected issue in which enabled front-panel display points can incorrectly be skipped in the rotating display. ➤ Corrected issue with scale factors not being applied to pickup settings in front-panel display points. ➤ Corrected issue with front-panel contrast not being retained when a TARGET RESET is executed. ➤ Added Multi-Recloser Interface compatibility.	20121219

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Table A.1   Firmware Revision History (Sheet 5 of 5)

Firmware Identification (FID) Number	Summary of Revisions	Manual Date Code
	➤ Global settings VYCOMP and VZCOMP are no longer hidden based on Global setting PHVOLT. ➤ Added Relay Word bit rows 124–135 to accommodate new features. ➤ Included new Compressed ASCII commands, CSU HIF, CEV HIF, and CHI HIF, in the **CAS** command response. ➤ Relay now reports the shot count from the trigger row of the event report.	
SEL-651R-2-R401-V1-Z002001-D20180615	Includes all the functions of SEL-651R-2-R401-V0-Z002001-D20120831 with the following addition: ➤ Resolved an issue where latch bits may be restored to an incorrect state after power is restored to the control or the control is restarted.	20180615
SEL-651R-2-R401-V0-Z002001-D20120831	➤ Made improvements for manufacturability.	20120831
SEL-651R-2-R400-V1-Z001001-D20180615	Includes all the functions of SEL-651R-2-R400-V0-Z001001-D20120518 with the following addition: ➤ Resolved an issue where latch bits may be restored to an incorrect state after power is restored to the control or the control is restarted.	20180615
SEL-651R-2-R400-V0-Z001001-D20120518	➤ Initial version.	20120518

Instruction Manual

The date code at the bottom of each page of this manual reflects the creation or revision date.

Table A.2 lists the instruction manual versions and revision descriptions. The most recent instruction manual version is listed first.

Table A.2   Instruction Manual Revision History (Sheet 1 of 8)

Revision Date	Summary of Revisions
20180615	**Appendix A** Updated for firmware versions R400-V1 and R401-V1.
20180131	**Preface** ➤ Added *Technical Assistance*. **Section 1** ➤ Added *Eaton NOVA NX-T Rating* to *Trip and Close Outputs* in *Specifications*. **Section 2** ➤ Added *Table 2.5: Default Global Setting CTPOL*. ➤ Added *Figure 2.78: Current Connections and Polarity for the Multi-Recloser Interface (Global Setting RECL_CFG := A3; Optional Voltage Connections Also Shown)*. **Section 5** ➤ Updated *Figure 5.2: Factory-Default Trip Logic Settings*. **Section 6** ➤ Updated *Table 6.8: Reclosing Relay SELOGIC Control Equation Settings*. ➤ Updated *Factory-Default 79DTL/79DLS Settings Example* in *Reclosing Relay*. ➤ Updated *Figure 6.11: Factory-Default Drive-to-Lockout Logic Settings*.

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Table A.2 Instruction Manual Revision History (Sheet 2 of 8)

Revision Date	Summary of Revisions
	Section 7 ➤ Updated *Table 7.2: Analog Quantities*. **Section 9** ➤ Updated *Figure 9.32: Logic Settings (SHO L) With Factory-Default Values*. **Appendix E** ➤ Updated *DNP3 Settings* under *DNP3 in the SEL-651R-2*. ➤ Added note explaining negative values in the FTIME*x* and FTYPE registers in *DNP3 Documentation*. **Appendix F** ➤ Added A3_CFG to *Table F.1: Relay Word Bit Mapping* and *Table F.2: Alphabetic List of Relay Word Bits*. **Appendix G** ➤ Updated *Table G.1: Analog Quantities*.
20171017	**General** ➤ Replaced references to Cooper/Kyle with Eaton. ➤ Added support and compatibility information for ABB OVR/Gridshield (32-pin and 42-pin version) reclosers. ➤ Updated base model offerings. **Preface** ➤ Updated *Trademarks*. **Section 1** ➤ Updated *Specifications*.
20170818	**Appendix A** Updated for firmware versions R403-V2, R405-V3, and R406-V1.
20170613	**Section 2** ➤ Added note about LEA circuit grounding to ABB OVR-3/VR-3S (15 and 27 kV Models) Reclosers discussion. ➤ Updated *Figure 2.55: Current Connections and Polarity From ABB OVR-3/VR-3S (15 and 27 kV Models) Recloser Primary to SEL-651R-2 Recloser Control Current Inputs*. ➤ Updated *Figure 2.57: Recloser Pole Status Connections Between ABB OVR-3/VR-3S (15 and 27 kV Models) Recloser and SEL-651R-2 Recloser Control*. ➤ Updated *Figure 2.61: 120 Vac Power Circuit Connections Between SEL-651R-2 Recloser Control and Control-Powered Kyle NOVA or G&W Control Power Viper-S Recloser*. ➤ Added note about shielded cables to G&W Viper-ST, G&W Viper-LT, or Elastimold MVR Reclosers discussion.
20161220	**Section 2** The following additions/changes make the de facto standard connections for ABB reclosers. ➤ Added current transformer secondary circuit ground and LEA sensor option for VY voltages to *Figure 2.55: Current Connections and Polarity From ABB OVR-3/VR-3S (15 and 27 kV Models) Recloser Primary to SEL-651R-2 Recloser Control Current Inputs*. ➤ Added yellow operating handle (ANSI device number 69) operation and 52a contact monitoring to *Figure 2.57: Recloser Pole Status Connections Between ABB OVR-3/VR-3S (15 and 27 kV Models) Recloser and SEL-651R-2 Recloser Control*. ➤ Changed ac power connections for recloser heater circuits from terminals C02/C03 to the actual connected terminals C01/C04 in *Figure 2.58: 120 Vac Power Circuit Connections Between SEL-651R-2 Recloser Control and ABB OVR-3/VR-3S (15 and 27 kV Models) Recloser*.
20160810	**Section 1** ➤ Updated *Communications Ports* in *Specifications* to clarify that 100BASE-FX rear ports use multimode LC fiber. ➤ Updated *Time-Overcurrent Elements (51)* in *Specifications* to change the lower end of the phase and negative-sequence pickup ranges from 0.10 to 0.05 A, secondary. ➤ Added 4 A specification to *AC Current Inputs* in *Specifications*. ➤ Added *AC Output Ratings* to *Output Contacts (Except Trip and Close)* in *Specifications*. ➤ Updated *Type Tests* information in *Specifications*.

Table A.2   Instruction Manual Revision History (Sheet 3 of 8)

Revision Date	Summary of Revisions
	Section 2
	➤ Updated *Figure 2.3: Rear View of SEL-651R-2 Power Module (Dual-Door Enclosure, Optional Features Shown)*.
	➤ Updated NEMA 3R and 3RX enclosure ratings in *Dual-Door Enclosure Overview* and *Single-Door Enclosure Overview*.
	➤ Clarified battery installation and connection steps accompanying *Figure 2.29: Battery Wiring Harness Connections (Shown Connected to Relay Module)*.
	Section 4
	➤ Updated *Figure 4.30: Synchronism-Check Voltage Window and Slip Frequency Elements* to clarify that the output of the 2 CYC timer is also the input into the AND gates for Relay Word bits SFAST, SSLOW, and SF.
	➤ Updated *Figure 4.31: Synchronism-Check Elements* and accompanying text to clarify that the slip frequency comparisons use absolute value of slip frequency.
	➤ Updated *Table 4.3: Maximum-Phase Time-Overcurrent Element Settings*, *Table 4.5: A- B-, or C-Phase Time-Overcurrent Element Settings*, and *Table 4.8: Negative-Sequence Time-Overcurrent Element Settings* to change the lower end of the phase and negative-sequence pickup ranges from 0.10 to 0.05 A, secondary.
	➤ Updated *Directional Control Settings* to include setting option E32 := AUTO2 and to explain its significance for the Z2F, Z2R, Z0F, and Z0R settings.
	Section 6
	➤ Clarified the realization of Relay Word bit 52A3P in *Figure 6.2: Breaker Status Logic*.
	Section 7
	➤ Added Relay Word bit DISTST to *Table 7.12: Asynchronous Processing Order of Relay Elements*.
	Section 8
	➤ Updated *Battery System Monitor* to define new Relay Word bit DISTST and describe how it can be used to provide a front-panel battery load test capability.
	Settings Sheets
	➤ Updated Maximum-Phase, A-Phase, B-Phase, C-Phase, and Negative-Sequence Time-Overcurrent Element settings to change the lower end of the phase and negative-sequence pickup ranges from 0.10 to 0.05 A, secondary.
	➤ Added setting option AUTO2 for directional elements enable setting E32.
	Section 10
	➤ Added wildcard usage examples in *Table 10.16: FTP and MMS Wildcard Usage Examples* and *Table 10.17: Ymodem Wildcard Usage Examples*.
	Appendix A
	➤ Updated for firmware version R406-V0.
	Appendix C
	➤ Added REF_NUM to *CHISTORY*, *CEVENTS*, and *CSU Command* outputs.
	➤ Added Relay Word bit DISTST to the CEVENT command output.
	Appendix E
	➤ Updated EXTTB and EXTTC phase designations in *Table E.11: DNP3 Reference Data Map*.
	➤ Added FWVNUM (Relay Firmware Version Number) to *Table E.11: DNP3 Reference Data Map*.
	Appendix F
	➤ Added Relay Word bit DISTST to Row 38 in *Table F.1: Relay Word Bit Mapping* and *Table F.2: Alphabetical List of Relay Word Bits*.
	Appendix G
	➤ Added FWVNUM (Relay Firmware Version Number) to *Table G.1: Analog Quantities*.
	➤ Removed erroneous "h" at the end of listings MVAR through kVAR in *Table G.1: Analog Quantities*.
	➤ Corrected listings KW3MND_[x] and KW3MNT_[z] in *Table G.1: Analog Quantities* (changed "X" to "N").
	➤ Added Group settings RID (Relay Identifier) and TID (Terminal Identifier) to *Table G.1: Analog Quantities*.
	Appendix I
	➤ Removed erroneous "VDC" in the description for "88 bytes" data in *Table I.5: A5D1 Fast Meter Data Block*.
	➤ Added Relay Word bit DISTST to the DNA command output.

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Table A.2 Instruction Manual Revision History (Sheet 4 of 8)

Revision Date	Summary of Revisions
	Appendix K
	➤ Added FWVNUM (Relay Firmware Version Number) to *Table K.22: Modbus Quantities Table*.
	Appendix L
	➤ Clarified that the Integer data type in *Table L.11* is Integer (INT8).
	➤ Added Logical Nodes BSASCBR1, BSBSCBR2, and BSCSCBR3 to *Table L.19: Logical Device: PRO (Protection*.
	➤ Added Logical Nodes BSASCBR1, BSBSCBR2, and BSCSCBR3 (with Data Source OC3) to *Table L.24: Logical Nodes by Data Source Names*.
	➤ Added Relay Word bit DISTST to *Table L.22: Logical Device: ANN (Annunciation)* and *Table L.24: Logical Nodes by Data Source Names*.
20160526	**Section 2**
	➤ Updated *Figure 2.41: Three-Phase Voltage Connections for 300 Vac Voltage Inputs*, *Figure 2.43: 8 Vac LEA Voltage Connections for VY-Terminal Voltages*, and *Figure 4.25: Lindsey SVMI LEA Voltage Connections for VZ-Terminal Voltages* with Terminals NY and NZ for new voltage input fuse blocks with wire insertion connections. The fuse blocks, along with shielded cables for LEA voltage inputs, are initially installed with the Multi-Recloser Interface.
20150722	**Appendix A**
	➤ Updated for firmware versions R405-V2, R403-V2, and R402-V1.
20150709	**Appendix A**
	➤ Updated for firmware version R405-V1.
	Appendix B
	➤ Updated *Overview* to include point release information.
20140731	**Section 1**
	➤ Updated specifications for *Optoisolated Inputs*, *Electromagnetic Compatibility Immunity*, and *Environmental Type Tests*.
	Section 2
	➤ Corrected Serial Port 2 and Port 3 voltage jumper label.
	➤ Modified *Figure 2.60: Trip/Close and Recloser Status Circuit Connections Between Control-Powered Kyle NOVA or G&W Control Power Viper-S Recloser and SEL-651R-2 Recloser Control* for additions to the 19-pin control cable interface.
	➤ Modified *Figure 2.73: Trip/Close, Recloser Status, and Lockout Handle Status Circuit Connections Between Siemens SDR Three-Phase Recloser and SEL-651R-2 Recloser Control*.
	Section 7
	➤ Expanded *Optoisolated Inputs* to include the 125 Vdc option.
20140306	**Section 1**
	➤ Added maximum rate-of-change under Frequency and Rotation in *Specifications*.
	➤ Added neutral channel under Time-Overcurrent Elements in *Specifications*.
	➤ Added rate-of-change-of-frequency element in *Specifications*.
	➤ Added Radiated Radio Frequency Immunity under Electromagnetic Compatibility Immunity in *Specifications*.
	Section 2
	➤ Changed the outline and re-organized entire section.
	Section 4
	➤ Added *Neutral Time-Overcurrent Elements* subsection.
	➤ Added *Rate-of-Change-of-Frequency (81R) Protection* subsection.
	➤ Changed Z0ANG to Z0MTA in *Figure 4.56: Zero-Sequence Voltage-Polarized Directional Element for Ground Overcurrent Elements* and *Figure 4.63: Zero-Sequence Impedance Plot for Solidly Grounded, Mostly Inductive System*.
	➤ Added *Z0MTA—Zero-Sequence Maximum Torque Angle* subsection.
	Section 6
	➤ Added missing figure for the Joslyn TriMod 600R recloser in *Figure 6.11: Factory Default Drive-to-Lockout Logic Settings*.

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Table A.2   Instruction Manual Revision History (Sheet 5 of 8)

Revision Date	Summary of Revisions
	Section 7
	➤ Changed the number of math variables from 32 to 64 in *Table 7.2: Analog Quantities*.
	➤ Added *Processing Order and Processing Interval* subsection.
	Section 9
	➤ Updated warning message displayed when EGNDSW changed from N to Y.
	➤ Added 0 to the MAXACC setting range.
	➤ Added default settings to detect control cable disconnection and yellow handle operation in *Figure 9.32: Logic Settings (SHO L) With Factory Default Values* and *Figure 9.33: Front-Panel Settings (SHO F) With Factory Default Values (Without Tricolor LED Option)*.
	➤ Added Group setting Neutral Time-Overcurrent Elements, Z0MTA, in *SEL-651R Settings Sheets*.
	➤ Added Group settings Rate-of-Change-of-Frequency Element, MV32–MV64, in *SEL-651R Settings Sheets*.
	➤ Added Port setting EMMSFS in *SEL-651R Settings Sheets*.
	Section 10
	➤ Added explanation for setting MAXACC = 0.
	➤ Added *Virtual File Interface* subsection.
	➤ Added **ETH C** command, and updated **ETH** command response.
	Section 13
	➤ Corrected errors for Input Channels column in *Table 13.1: Resultant Scale Factors for Input Module*.
	Appendix A
	➤ Updated for firmware version R405-V0.
	Appendix E
	➤ Updated *Figure E.3: Sample Response to SHO D Command* and *Figure E.8: Binary Output Map Entry in ACSELERATOR QuickSet Software*.
	➤ Clarified switching between single- and multi-event modes under *Reading Relay Events* subsection.
	➤ Added Pickup settings as primary quantities under *Settings Data* subsection under *Analog Inputs*.
	➤ Added MAXWEAR and updated number of math variables from 32 to 64 in *Table E.11: DNP3 Reference Data Map*.
	➤ Added clarification for upper byte before *Table E.12: Object 30, Fault Type Upper Byte—Event Cause*.
	➤ Added explanation for setting RSTDNPE under *Reading Relay Events* subsection.
	➤ Updated the number of binary outputs to 71 in *Table E.16: SEL-651R-2 DNP3 Default Data Map*.
	Appendix F
	➤ Added Relay Word bits for neutral time-overcurrent elements, rate-of-change-of-frequency (81R) elements, and RSTDNPE.
	Appendix G
	➤ Added MAXWEAR, FLREP, FLRNUM, HIFLREP, HIFLRNUM, Primary Quantities of Time-Overcurrent Pickup settings to *Table G.1: Analog Quantities*.
	➤ Updated number of Math Variables to 64 in *Table G.1: Analog Quantities*.
	Appendix I
	➤ Corrected message length to 28 in *Table I.3: A5CO Relay Definition Block*.
	Appendix J
	➤ Added *Table J.17: Time Quality Decoding* to decode time quality.
	Appendix K
	➤ Added MAXWEAR and updated math variables to 64 in *Table K.22: Modbus Quantities Table*.

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Table A.2   Instruction Manual Revision History (Sheet 6 of 8)

Revision Date	Summary of Revisions
	Appendix L
	➤ Added explanation for MMS file transfer services under *File Services* subsection.
	➤ Added *GOOSE Receive and Transmit Capacity* subsection under *GOOSE Processing and Performance*.
	➤ Added EMMSFS setting to *Table L.14: IEC 61850 Settings*.
	➤ Added explanation on retaining the CID file when a bad CID file is loaded in *Settings* under the *IEC 61850 Configuration* subsection.
	➤ Added an explanation for MMS authentication in ACSELERATOR Architect under the *IEC 61850 Configuration* subsection.
	➤ Added neutral time-overcurrent elements to *Table L.19: Logical Device: PRO (Protection)*.
	➤ Updated the number of math variables to 64 in *Table L.22: Logical Device: ANN (Annunciation)*.
	➤ Added 51N1, 51N1T, 51N2, 51N2T, FLREP, FLRNUM, HIFLREP, HIFLRNUM, and MAXWEAR to *Table L.24: Logical Nodes by Data Source Names*.
20130624	**Settings Sheets**
	➤ Added Setting RESPSZ.
	Appendix A
	➤ Updated for firmware version R403-V0.
	Appendix E
	➤ Updated *Table E.6: SEL-651R-2 Port DNP Protocol Settings*.
	➤ Update *Table E.9: SEL-651R-2 DNP3 Device Profile*.
20130508	**Section 2**
	➤ Modified *Figure 2.63 Trip/Close and Recloser Pole Status Circuit Connections Between Kyle NOVA-TS or NOVA-STS Triple-Single Recloser and SEL-651R-2 Recloser Control* and *Figure 2.64 Yellow Lockout Handle Circuit Connections Between Kyle NOVA-TS or NOVA-STS Triple-Single Recloser and SEL-651R-2 Recloser Control* by adding 53 Vdc to Pin C to support Kyle NOVA-STS recloser.
	➤ Verified connection of pins D, N, P, L, and R in *Figure 2.63 Trip/Close and Recloser Pole Status Circuit Connections Between Kyle NOVA-TS or NOVA-STS Triple-Single Recloser and SEL-651R-2 Recloser Control*.
20121219	**Section 1**
	➤ Added *Second Harmonic Blocking Logic* and the *Tavrida OSM Al_4* to *Specifications*.
	Section 2
	➤ Added *Multi-Recloser Interface* subsection
	Section 4
	➤ Added *Second Harmonic Blocking Logic* subsection.
	➤ Enhanced *Generator Application for SSLOW and SFAST* in the *Synchronism Check Elements* subsection.
	➤ Added *Load Encroachment for Directionally Controlled Elements* and *Load Encroachment for Nondirectional Elements* with examples to the *Load-Encroachment Logic* subsection.
	➤ Added *High-Impedance Fault Detection (Arc Sense Technology)* subsection.
	➤ Added *50G High-Impedance (HIZ) Fault Detection* subsection.
	Section 5
	➤ Added Multi-Recloser Interface "Yellow Operating Handle" trip logic to *Figure 5.2*, and *69_YH Relay Word bit for Multi-Recloser Interface* subsection.
	Section 6
	➤ Added Multi-Recloser Interface note to *Breaker Status Logic*.
	➤ Changed 79RSLD "reset time from lockout" lower range to 0 cycles in *Table 6.6*.
	➤ Added Multi-Recloser Interface "Yellow Operating Handle" drive-to-lockout logic to *Table 6.8* and *Figure 6.11*.
	Section 7
	➤ Added Multi-Recloser Interface note to *Trip and Close Mapping and Output Logic* subsection.
	Section 8
	➤ Added *High-Impedance Fault Metering* subsection.
	➤ Added Multi-Recloser Interface notes to *Breaker/Recloser Contact Wear Monitor* subsection.

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Table A.2 Instruction Manual Revision History (Sheet 7 of 8)

Revision Date	Summary of Revisions
	Section 9
	➤ Added notes to *Current and Voltage Connections (Global Settings)*, *Breaker Monitor Initiate Settings (Global Settings)*, *Potential Transformer (PT) Ratios (Group Settings)*, and *Pole Status (52a), Trip, and Close Mapping Variations for Single-Phase Trip Capable Reclosers (Group Settings)* subsections to explain settings differences for the Multi-Recloser Interface.
	➤ Added settings for High-Impedance Fault Detection, 50G High-Impedance (HIZ) Detection, Second Harmonic Blocking, and the Multi-Recloser Interface (Global setting RECL_CFG) to the *SEL-651R-2 Settings Sheets*.
	➤ Changed 79RSLD "reset time from lockout" lower range to 0 cycles in *SEL-651R-2 Settings Sheets*.
	Section 10
	➤ Updated *Figure 10.5* and *Figure 10.6* to reflect new web server display.
	➤ Updated **FILE** command explanation to include HF_nnnnn.* (high-impedance fault) and HR_nnnnn.* (standard raw) COMTRADE event reports.
	➤ Added **HIS E** command, and updated **CEV** and **EVE** commands to accept unique event numbers.
	➤ Added **CEV HIF**, **CHI HIF**, **HIS HIF**, **INI HIF**, **LOG HIF, MET HIF**, **SUM HIF**, and **TRI HIF** commands for High-Impedance Fault (HIF) Detection to *Command Summary* and *Command Explanations* subsections.
	➤ Added **HIZ** command for 50G High-Impedance (HIZ) Fault Detection to *Command Summary* and *Command Explanations* subsections.
	Section 12
	➤ Added COMTRADE file format event reports to the *Standard 15/30/60-Cycle Event Reports* subsection and modified outline of subsection.
	➤ Added **HIS E** command (unique event numbers).
	➤ Added *High-Impedance Fault Event Reporting* subsection.
	➤ Changed the event report row that is used to determine the shot count.
	Section 13
	➤ Added the *Low-Level Test Interface* subsection.
	Appendix A
	➤ Updated for firmware version R402-V0.
	Appendix B
	➤ Added Important Note regarding upgrade path from R400 via Web Server.
	Appendix C
	➤ Added compressed reports for High-Impedance Fault Detection throughout section.
	Appendix F
	➤ Added Relay Word bits for High-Impedance Fault Detection, 50G High-Impedance (HIZ) Detection, Second Harmonic Blocking, and the Multi-Recloser Interface throughout section.
	Appendix I
	➤ Added note regarding communications processor compatibility.
	Appendix J
	➤ Revised PMSTN setting to allow mixed case.
	➤ Added *Table J.6: C37.118 Data Frame*.
	➤ Revised *Configuring High-Accuracy Timekeeping* for change in parity checking.
	Appendix K
	➤ Added new Relay Element Status Rows to *Table K.7* and *Table K.22* for High-Impedance Fault Detection, 50G High-Impedance (HIZ) Detection, Second Harmonic Blocking, and the Multi-Recloser Interface Relay Word bits.

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Table A.2   Instruction Manual Revision History (Sheet 8 of 8)

Revision Date	Summary of Revisions
20120928	**Section 1** ➤ Updated *Models and Options*. ➤ Updated *Applications*. ➤ Updated *Specifications*. **Section 2** ➤ Updated *Figure 2.45: Control Cable Receptacle Pinouts*. ➤ Added *Multi-Recloser Interface* subsection. **Section 7** ➤ Included Tavrida OSM Al_4 for the Multi-Recloser Interface. **Section 9** ➤ Added default settings for Tavrida OSM Al_4 for the Multi-Recloser Interface.
20120831	**Appendix A** ➤ Updated for firmware version R401-V0.
20120518	➤ Initial version.

Appendix B

Firmware Upgrade Instructions

Overview

These instructions guide you through the process of upgrading firmware in the device. The firmware upgrade will be either a standard release or a point release. A standard release adds new functionality to the firmware beyond the specifications of the existing version. A point release is reserved for modifying firmware functionality to conform to the specifications of the existing version.

A standard release is identified by a change in the R-number of the device firmware identification (FID) number.

Existing firmware:

FID=SEL-651R-2-**R100**-Vx-Zxxxxxx-Dxxxxxxxx

Standard release firmware:

FID=SEL-651R-2-**R101**-Vx-Zxxxxxx-Dxxxxxxxx

A point release is identified by a change in the V-number of the device FID number.

Existing firmware:

FID=SEL-651R-2-Rxxx-**V0**-Zxxxxxx-Dxxxxxxxx

Point release firmware:

FID=SEL-651R-2-Rxxx-**V1**-Zxxxxxx-Dxxxxxxxx

The release date is after the D. For example, the following is firmware version number R100, release date December 10, 2003.

FID=SEL-651R-2-R100-Vx-Zxxxxxx-**D20031210**

The instructions that follow explain how you can install new firmware in your SEL-651R-2 Recloser Control with Ethernet. These instructions are for firmware upgrades only and do not provide complete instructions for part number changes. If a part number change is required, contact SEL for assistance.

This appendix contains the following subsections:

➤ *Relay Firmware Upgrade Methods on page B.2*

➤ *Method One: Using QuickSet Firmware Loader on page B.3*

➤ *Method Two: Using a Terminal Emulator on page B.8*

➤ *Method Three: Using a Web Browser on page B.14*

➤ *Solving Firmware Upgrade Issues on page B.18*

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B.2 | Firmware Upgrade Instructions
Relay Firmware Upgrade Methods

Relay Firmware Upgrade Methods

Introduction

These firmware upgrade instructions apply to SEL-651R-2 recloser controls with at least one Ethernet port.

SEL occasionally offers firmware upgrades to improve the performance of your relay. Changing physical components is unnecessary because the relay stores firmware in Flash memory.

A firmware loader program called SELBOOT resides in the relay. To upgrade firmware, use the SELBOOT program to download an SEL-supplied file from a personal computer to the relay via the USB port, a serial port, or use the built-in web server over an Ethernet port.

Keep the AC Power On!

When upgrading firmware, make sure to keep the SEL-651R-2 energized with ac power—do not have it running just off the battery. Otherwise, when the **L_D** command is issued later in the firmware upgrade procedure (to disable the unit to receive new firmware), the unit goes immediately "to sleep," thus aborting the firmware upgrade procedure.

NOTE: SEL strongly recommends that you upgrade firmware at the location of the relay and with a direct connection from the personal computer to the USB port or one of the relay serial ports. Do not load firmware from a remote location while the control is in service. Problems can arise that you may not be able to address from a distance. When upgrading at the substation, do not attempt to load the firmware into the relay through an SEL communications processor.

IMPORTANT NOTE: When upgrading firmware from R400 via the web server, to maintain user settings, upgrade to R401 first, then upgrade to the desired release (e.g., to upgrade from R400 to R4xx, upgrade from R400 to R401, and then upgrade from R401 to R4xx). Failure to comply will result in loss of user settings and default settings will be restored. Therefore, web server communication will be disabled (default setting EHTTP = N).

The firmware upgrade can be performed one of three ways:

➤ Method One: Use the Firmware Loader provided within ACSELERATOR QuickSet SEL-5030 Software. The Firmware Loader automates the firmware upgrade process.

➤ Method Two: Connect to the relay in a terminal session and upgrade the firmware by using the steps documented in *Method Two: Using a Terminal Emulator*.

➤ Method Three: Establish an Ethernet connection and use a web browser to access the embedded web server. Upgrade the firmware by using the steps documented in *Method Three: Using a Web Browser*. This is the fastest method to complete an upgrade.

The same basic actions are required in all methods:

A. Obtain the firmware file

B. Remove relay from service

C. Establish communications with the relay

D. Prepare the relay (save settings and other data)

E. Perform firmware upgrade

F. Check relay self-tests

G. Verify relay settings

H. Return the relay to service

Required Equipment

Gather the following equipment before starting this firmware upgrade:

➤ Personal computer

➤ To use Method One, QuickSet

➤ To use Method Two, terminal emulation software that supports 1K Xmodem or Xmodem (these instructions use HyperTerminal from a Microsoft Windows operating system)

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Firmware Upgrade Instructions   B.3
Digitally Signed Firmware Files

➤ For Methods One and Two, serial communications cable (SEL-C234A, SEL-C662 USB-to-232 converter, or equivalent) or USB cable (SEL-C664 or equivalent)

➤ To use Method Three, an Ethernet connection and compatible web browser

➤ Disk containing the firmware upgrade (.zds) file

➤ Firmware Upgrade Instructions (these instructions)

➤ Your relay instruction manual

Digitally Signed Firmware Files

This device supports digitally signed firmware upgrades. These firmware upgrade files are compressed to reduce file transfer times and digitally signed by SEL using a secure hash algorithm. The signature ensures that the file has been provided by SEL and that its contents have not been altered. Once uploaded to the relay, the signature (and thus validity) of the firmware is verified with a public key number that is stored on the relay from the factory. If the signature cannot be verified, the file is rejected.

The name of the digitally signed firmware file is of the form Rxxx651R.zds or Rxxx-Vy651R.zds, where Rxxx is the firmware revision number, Vy is the point release revision number, 651R indicates the relay type, and .zds is the file extension reserved for digitally signed files.

Method One: Using QuickSet Firmware Loader

To use the QuickSet Firmware Loader, you must have QuickSet. See *Section 3: PC Software* for instructions on how to obtain and install the software. Once the software is installed, perform the firmware upgrade as follows.

A. Obtain Firmware File

The firmware file is usually provided on a CD-ROM. Locate the firmware file on the disc. Copy the firmware file to an easily accessible location on the PC.

Firmware is designed to be used with specific relays. A list of relay serial numbers is provided as part of the firmware upgrade package. The firmware provided is for use with the listed relays only. Attempts to upgrade relays not listed will not be successful and can result in relay failure.

B. Remove Relay From Service

Step 1. If the relay is in use, follow your company practices for removing a relay from service. Typically, these include changing settings, or disconnecting external voltage sources or output contact wiring, to disable relay control functions.

Step 2. Apply ac power to the control.

B.4 | Firmware Upgrade Instructions
Method One: Using QuickSet Firmware Loader

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Step 3.   Connect a communications cable and determine the port speed.

If using the EIA-232 front port to upgrade firmware, determine the port speed as follows:

   a.   From the relay front panel, press the ENT pushbutton.

   b.   Use the arrow pushbuttons to navigate to Set/Show and press the ENT pushbutton.

   c.   Use the arrow pushbuttons to navigate to **PORT**.

   d.   Press the ENT pushbutton.

   e.   Use the arrow pushbuttons to navigate to the relay serial port you plan to use (usually the front port).

   f.   Press the ENT pushbutton.

   g.   With **Communication Settings** selected, press the ENT pushbutton.

   h.   Press the down arrow pushbutton to scroll through the port settings; write down the value for each setting.

   i.   Connect an SEL-C234A EIA-232 serial cable, SEL-C662 USB-to-232 converter, or equivalent communications cable to the relay serial port and to the PC.

If using the relay front-panel USB port to upgrade firmware, connect an SEL-C664 cable between the relay and the PC. The USB port appears as a serial connection. Any data rate will be accepted by the relay.

C. Establish Communications With the Relay

Use the **Communications > Parameters** menu of QuickSet to establish a connection. See *Section 3: PC Software* for additional information.

D. Prepare the Relay (Save Relay Settings and Other Data)

It is possible for data to be lost during the firmware upgrade process. Follow the steps in this section carefully to ensure that important data are saved.

Step 1.   Select **Tools > Firmware Loader** and follow the on-screen prompts.

Step 2.   In the Step 1 of 4 window of the Firmware Loader, click the ellipsis button and navigate to the location of the firmware file. Select the file and click **Open** (see *Figure B.1*).

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Firmware Upgrade Instructions   B.5
Method One: Using QuickSet Firmware Loader

Figure B.1   Prepare the Device (Step 1 of 4)

Step 3.   Select the **Save calibration settings** check box in the Step 1 of 4 window of the Firmware Loader. These factory-default settings are required for proper operation of the relay and must be reentered in the unlikely event they are erased during the firmware upgrade process. The Firmware Loader saves the settings in a text file on the PC.

Step 4.   Select the **Save device settings** check box if you do not have a copy of the relay settings. It is possible for relay settings to be lost during the upgrade process.

Step 5.   Select the **Save events** check box if there are any event reports that have not been previously saved. It is possible for event reports to be lost during the upgrade process.

Step 6.   Click **Next**.

The Firmware Loader reads the calibration settings and saves them in a text file on the PC. Make note of the file name and the location.

If **Save device settings** was selected, the Firmware Loader reads all of the settings from the relay. The software may ask if you wish to merge the settings read from the relay with existing design templates on the PC. Click **No, do not merge settings with Design Template**. The Firmware Loader will suggest a name for the settings, but the suggested name can be modified as desired.

If **Save events** was selected, the Event History window will open to allow the events to be saved. See *QuickSet Event Analysis on page 3.18* for more information.

Step 7.   If you use the Breaker Wear Monitor, click the **Terminal** button in the lower left portion of the Firmware Loader to open the terminal window. From the Access Level 1 prompt, issue the **BRE** command and record the internal and external trip counters, internal and external trip currents for each phase, and breaker wear percentages for each phase.

B.6 | Firmware Upgrade Instructions
Method One: Using QuickSet Firmware Loader

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Step 8. Enable Terminal Logging capture (see *QuickSet Terminal on page 3.5*) and issue the following commands to save stored data. It is possible for these data to be lost during the firmware upgrade process. (Some of these features are not available on all relay models.)

   a. **MET E**—accumulated energy metering

   b. **MET D**—demand and peak demand

   c. **MET M**—maximum/minimum metering

   d. **COMM A** and **COMM B**—MIRRORED BITS communications logs

   e. **LDP**—Load Profile

   f. **SSI**—Voltage sag, swell, interrupt recorder

   g. **SER**—Sequential Events Report

E. Start SELBOOT

In the Step 2 of 4 window of the Firmware Loader, click **Next** to disable the relay and enter SELBOOT (see *Figure B.2*).
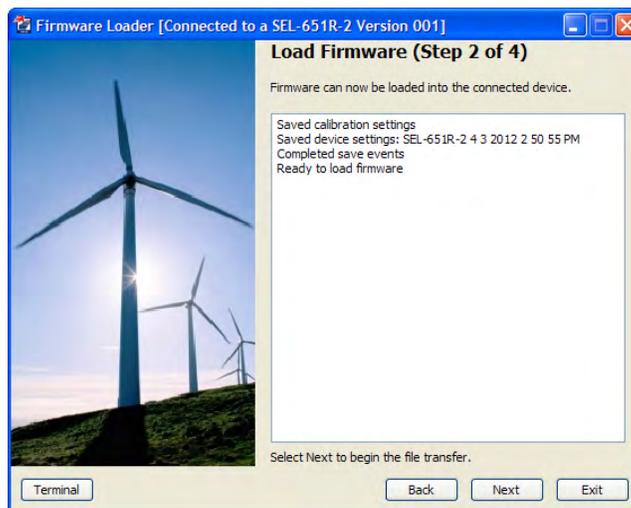
Figure B.2   Load Firmware (Step 2 of 4)

G. Upload New Firmware

This step is performed automatically by the software. The software will erase the existing firmware and start the file transfer to upload the new firmware. Upload progress will be shown in the **Transfer Status** window.

When the firmware upload is complete, the relay will restart. The Firmware Loader will automatically re-establish communications and issue a **STA** command to the relay.

If the relay does not restart within two minutes of the firmware upload completion (as indicated by the PC application) and no error messages appear on the relay HMI, cycle power to the relay. The firmware loader application should then resume. Click **Yes** if the Firmware Loader prompts you to continue.

H. Check Relay Self-Tests

The Step 3 of 4 window of the Firmware Loader will indicate that it is checking the device status and when the check is complete (see *Figure B.3*). The software will notify you if any problems are detected. You can view the

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Method One: Using QuickSet or Firmware Loader
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relay status by clicking the **Terminal** button in the lower left portion of the Firmware Loader. If status failures are shown, open the terminal and see *Solving Firmware Upgrade Issues*.

Click **Next** to go to the completion step.
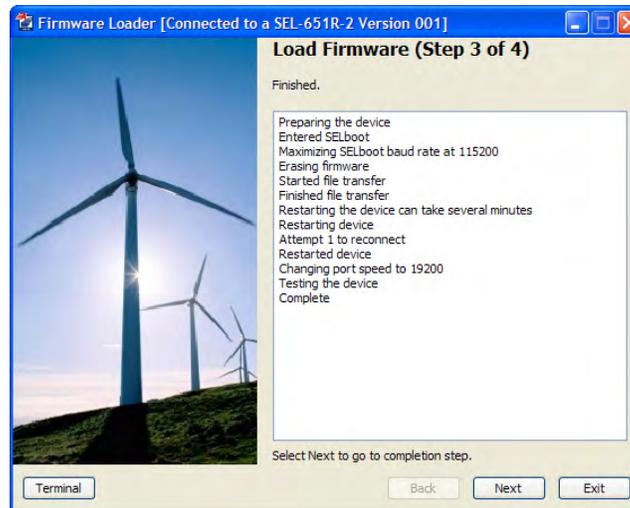
Figure B.3   Load Firmware (Step 3 of 4)

I. Verify Relay Settings

If there are no failures, the relay will enable. In the Step 4 of 4 window (see *Figure B.4*), the Firmware Loader will give you the option to compare the device settings. If any differences are found, the software will provide the opportunity to restore the settings.

Figure B.4   Verify Device Settings (Step 4 of 4)

J. Return Relay to Service

Step 1.   Open the terminal window by clicking the **Terminal** button in the lower left portion of the Firmware Loader.

Step 2.   Use the **ACC** command with the associated password to enter Access Level 1.

B.8 | Firmware Upgrade Instructions
Method Two: Using a Terminal Emulator

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Step 3. Issue the **ID** command and compare the firmware revision (Rxxx) displayed in the FID string against the number from the firmware envelope label. If the numbers match, proceed to *Step 5*.

Step 4. For a mismatch between a displayed FID and the firmware envelope label, reattempt the upgrade or contact SEL for assistance.

Step 5. If you use the Breaker Wear Monitor, type **BRE <Enter>** to check the data to see if the relay retained breaker wear data through the upgrade procedure. If the relay did not retain these data, use the **BRE W** command to reload the percent contact wear values recorded in *D. Prepare the Relay (Save Relay Settings and Other Data) on page B.4*.

Step 6. Apply current and voltage signals to the relay.

Step 7. Type **MET <Enter>** or use the QuickSet HMI to verify that the current and voltage signals are correct.

Step 8. Use the **TRI** and **EVE/CEV** commands or **Tools > Events > Get Events** menu in QuickSet to verify that the magnitudes of the current and voltage signals you applied to the relay match those displayed in the event report. If these values do not match, check the relay settings and wiring.

Step 9. Autoconfigure the SEL communications processor port if you have an SEL communications processor connected to the relay. This step reestablishes automatic data collection between the SEL communications processor and the relay. Failure to perform this step can result in automatic data collection failure when cycling communications processor power.

Step 10. Follow your company procedures for returning a relay to service.

Method Two: Using a Terminal Emulator

The instructions for this section use HyperTerminal as a terminal emulator. If HyperTerminal is not used, certain instructions may have to be modified (different menu names used) to execute the step.

A. Obtain Firmware File

Follow the directions under *A. Obtain Firmware File on page B.3*.

B. Remove Relay From Service

Follow the directions under *B. Remove Relay From Service on page B.3*.

C. Establish Communications With the Relay

Refer to *Establishing Communications Using a Serial Port on page 10.1*. If using the relay front-panel USB port, a port driver must be installed on the PC (see *Establishing Communications Through Use of the USB Port on page 10.2*).

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Method Two: Using Terminal Emulator

D. Prepare the Relay (Save Relay Settings and Other Data)

It is possible for data to be lost during the firmware upgrade process. Follow the steps in this section carefully to ensure that important data are saved.

Before upgrading firmware, retrieve and record any History (**HIS**) or Event (**EVE**, **CEV**) data that you want to retain. See *Section 10: Communications* for an explanation of the commands. During this process, you may find it helpful to use the Capture Text feature of Terminal Emulator. See additional instructions for using Capture Text in *Backup Relay Settings and Other Data*.

Enter Access Level 2

NOTE: If the relay does not prompt you for Access Level 1 and Access Level 2 passwords, check whether the relay Access jumper is in place. With this jumper in place, the relay is unprotected from unauthorized access (see Section 2: Installation).

Step 1. Type **ACC <Enter>** at the Access Level 0 = prompt.

Step 2. Type the Access Level 1 password and press **<Enter>**.

You will see the Access Level 1 => prompt.

Step 3. Type **2AC <Enter>**.

Step 4. Type the Access Level 2 password and press **<Enter>**.

You will see the Access Level 2 =>> prompt.

Backup Relay Settings and Other Data

The relay preserves settings and passwords during the firmware upgrade process. However, interruption of relay power during the upgrade process can cause the relay to lose settings. Make a copy of the original relay settings in case you need to reenter the settings. Use either the SEL-5010 Relay Assistant software or QuickSet to record the existing relay settings and proceed to *E. Start SELBOOT*. Otherwise, perform the following steps:

Step 1. From the **Transfer** menu in **HyperTerminal**, select **Capture Text**.

Step 2. Enter a directory and file name for a text file where you will record the existing relay settings.

Step 3. Click **Start**.

The **Capture Text** command copies all the information you retrieve and all the keystrokes you type until you send the command to stop capturing text. The terminal emulation program stores these data in the text file.

Step 4. Execute the Show Calibration (**SHO C**) command to retrieve the relay calibration settings.

Use the following Show commands to retrieve the relay settings: **SHO F**, **SHO G**, **SHO 1**, **SHO L 1**, **SHO 2**, **SHO L 2**, **SHO 3**, **SHO L 3**, **SHO 4**, **SHO L 4**, **SHO 5**, **SHO L 5**, **SHO 6**, **SHO L 6**, **SHO 7**, **SHO L 7**, **SHO 8**, **SHO L 8**, **SHO P 1**, **SHO P 2**, **SHO P 3**, **SHO P F**, **SHO P 5**, **SHO R**, **SHO D 1**, **SHO D 2**, **SHO D 3**, and **SHO M**.

Step 5. Issue the following commands to save stored data. It is possible for these data to be lost during the firmware upgrade process. (Some of these features are not available on all relay models.)

a. **MET E**—accumulated energy metering

b. **MET D**—demand and peak demand

c. **MET M**—maximum/minimum metering

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Method Two: Using a Terminal Emulator

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d. **COMM A** and **COMM B**—MIRRORED BITS communications logs

e. **LDP**—Load Profile

f. **SSI**—Voltage sag, swell, interrupt recorder

g. **SER**—Sequential Events Report

h. **BRE**—Breaker Wear Monitor data

Step 6. From the **Transfer** menu in **HyperTerminal**, select **Capture Text** and click **Stop**.

Step 7. The computer saves the text file you created to the directory you specified in *Step 2*.

Step 8. Write down the present relay data transmission setting (SPEED) for the port to be used for the firmware upgrade.

The SPEED setting is included in the **SHO P** relay settings output. The SPEED value should be the same as the value you recorded in *B. Remove Relay From Service on page B.8*.

E. Start SELBOOT

NOTE: A message similar to the following may be displayed when you type **L_D <Enter>**: "WARNING: Settings were not properly saved – Settings upgrade may fail. Please contact an SEL representative if assistance is required." Some relays have an automatic settings backup routine. This message indicates that the backup was not successful. If you saved settings as instructed in Backup Relay Settings and Other Data on page B.9, continue with the firmware upgrade process. Otherwise, type **EXI** at the prompt to exit SELBOOT. Follow the instructions under Backup Relay Settings and Other Data on page B.9 to ensure that the existing settings are available after the firmware upgrade.

Step 1. From the computer, start the SELBOOT program:

a. From the Access Level 2 =>> prompt, type **L_D <Enter>**.

The relay responds with the following:

```
Disable relay to send or receive firmware
(Y/N)?
```

b. Type **Y <Enter>**.

The relay responds with the following:

```
Are you sure (Y/N)?
```

c. Type **Y <Enter>**.

The relay responds with the following:

```
Relay Disabled
```

Step 2. Wait for the SELBOOT program to load.

The front-panel LCD screen displays SELBOOT. The computer will display the SELBOOT !> prompt after SELBOOT loads.

Step 3. Press **<Enter>** to confirm that the relay is in SELBOOT.

You will see another SELBOOT !> prompt.

Commands Available in SELBOOT

For a listing of commands available in SELBOOT, type **HELP <Enter>**. You should see a screen similar to *Figure B.5*.

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```
!>HELP <Enter>
BFID=SLBT-3CF1-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx
USBID=1.1 (015)

Baud                   - Set to a standard baud rate from 300 to 115200 bps.
Erase                  - Erase the existing firmware.
Exit                   - Exit this program and restart the device.
FID                    - Display the firmware identification (FID).
Receive [BOOT | KEY] - Receive new firmware/key for the device using Xmodem.
Help                   - Print this help list.

Program Memory Size: 01000000
Firmware Checksum = B9DC  OK

!>
```

Figure B.5   List of Commands Available in SELBOOT

F. Maximize Port Data Rate for EIA-232 Ports

Step 1.   Type **BAU 115200 <Enter>** at the SELBOOT !> prompt.

Step 2.   Change the **Bits per second** setting in the **Com Properties** of the terminal emulator software to 115200.

> **NOTE:** The USB port speed is fixed. If you are using the USB port for the firmware upgrade, continue to G. Upload New Firmware.

G. Upload New Firmware

Step 1.   Type **REC <Enter>** at the SELBOOT !> prompt to command the relay to receive new firmware.

```
!>REC <Enter>
Caution! -  This command erases the relays firmware.
If you erase the firmware, new firmware must be loaded into the relay
before it can be put back into service.
```

The relay asks whether you want to erase the existing firmware.

```
Are you sure you wish to erase the existing firmware? (Y/N) Y
```

Step 2.   Type **Y** to erase the existing firmware and load new firmware. (To abort, type **N** or press **<Enter>**).

The relay responds with the following:

```
Erasing
Erase successful
Press any key to begin transfer, then start transfer at the PC <Enter>
```

Step 3.   Press **<Enter>** to start the file transfer routine.

Step 4.   Send new firmware to the relay.

    a.   From the **Transfer** menu in HyperTerminal, choose **Send File** (see *Figure B.6*).
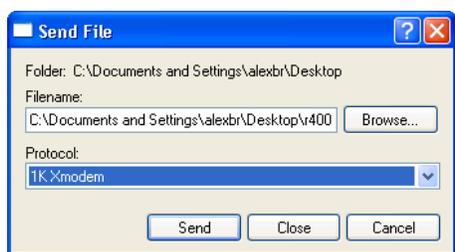
Figure B.6   Selecting New Firmware to Send to the Relay

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b. In the **Filename** text box, type the location and filename of the new firmware or use the **Browse** button to select the firmware file.

c. In the **Protocol** text box, select **1K Xmodem** if this protocol is available.

If the computer does not have **1K Xmodem**, select **Xmodem**.

d. Click **Send** to send the file containing the new firmware.

NOTE: The relay restarts in SELBOOT if relay power fails while receiving new firmware. Upon power-up, the relay serial port will be at the default 9600 bps. Perform the steps beginning in C. Establish Communications With the Relay to increase the serial connection data speed. Then resume the firmware upgrade process at G. Upload New Firmware.
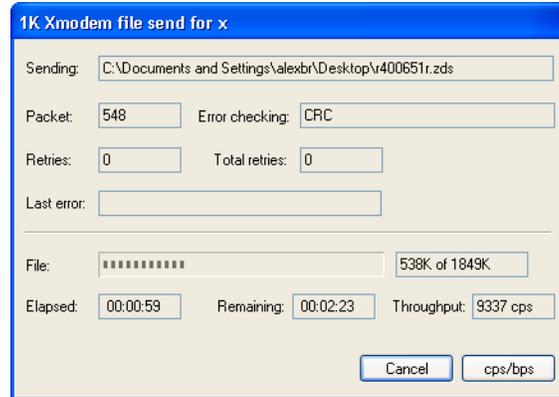
Figure B.7   Transferring New Firmware to the Relay

You should see a dialog box similar to *Figure B.7*. Incrementing numbers in the **Packet** box and a bar advancing from left to right in the **File** box indicate that a transfer is in progress.

If you see no indication of a transfer in progress within a few minutes after clicking **Send**, use the **REC** command again and reattempt the transfer.

Step 5.   Wait for the transfer to be completed.

a. If you are using an EIA-232 port, the relay displays the following:

```
Upload completed successfully. Attempting a restart.
```

b. If you are using the front-panel USB port, the relay displays the following after the transfer is completed:

```
Upload completed successfully. Press any key to restart.
```

After a key is pressed, the relay displays:

```
Close the USB port and remove the USB cable.
Attempting a restart in 5 seconds.
```

From the **Call** menu of HyperTerminal, choose **Disconnect** and remove the USB cable from the front of the relay.

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Step 6.   Wait for relay to restart.

A successful restart sequence can take as long as two minutes, after which time the relay leaves SELBOOT. You will see no display on your PC to indicate a successful restart. A successful restart is indicated when the **ENABLED** LED illuminates. This LED is labeled either **EN** or **ENABLED**, depending on the relay model.

If the relay does not restart within two minutes of the firmware upload completion (as indicated by the PC terminal emulator) and no error messages appear on the relay HMI, cycle power to the relay. Re-establish your connection in HyperTerminal and continue with Step 7.

In some cases, the **ENABLED** LED may not illuminate and a `FAIL` message will be displayed on the relay LCD screen, if equipped.

Step 7.   Change the **Bits per second** setting in the **Com Properties** of the terminal emulator software to match what was recorded in *Step 8* of *Backup Relay Settings and Other Data on page B.9*. Press **<Enter>** and confirm that the Access Level 0 = prompt appears on the computer screen.

If you are using the relay front-panel USB port, you will need to reestablish the connection.

   a.   Reinstall the cable.

   b.   From the **Call** menu of HyperTerminal, choose **Call** and press **<Enter>** several times, until you see the `Access Level 0 =` prompt.

Step 8.   If you see the `Access Level 0 =` prompt, proceed to *H. Check Relay Self-Tests*.

No Access Level 0 = Prompt

If no `Access Level 0 =` prompt appears in the terminal emulation window, one of several things could have occurred. Refer to *Table B.1* to determine the best solution:

Table B.1   Troubleshooting New Firmware Upload (Sheet 1 of 2)

Problem	Solution
The restart was successful, but the relay data transmission rate reverted to the rate at which the relay was operating prior to entering SELBOOT (the rate you recorded in *B. Remove Relay From Service*).	Change the computer terminal speed to match the relay data transmission rate you recorded in *B. Remove Relay From Service*. Step 1. From the **Call** menu, choose **Disconnect** to terminate relay communication. Step 2. Change the communications software settings to the values you recorded in *B. Remove Relay From Service*. Step 3. From the **Call** menu, choose **Call** to reestablish communication. Step 4. Press **<Enter>** to check for the Access Level 0 = prompt indicating that serial communication is successful.
The restart was successful, but the relay data transmission rate reverted to 9600 bps (the settings have been reset to default).	Match the computer terminal speed to a relay data transmission rate of 9600 bps. Step 1. From the **Call** menu, choose **Disconnect** to terminate relay communication. Step 2. Change the communications software settings to 9600 bps, 8 data bits, no parity, and 1 stop bit (see *F. Maximize Port Data Rate for EIA-232 Ports*). Step 3. From the **Call** menu, choose **Call** to reestablish communication. Step 4. Press **<Enter>** to check for the Access Level 0 = prompt indicating successful serial communication.

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Method Three: Using a Web Browser

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Table B.1   Troubleshooting New Firmware Upload (Sheet 2 of 2)

Problem	Solution
The restart was unsuccessful, in which case the relay is in SELBOOT, indicated by a SELBOOT !> prompt.	If you see a SELBOOT !> prompt, type **EXI <Enter>** to exit SELBOOT. Check for the Access Level 0 = prompt. If you see the Access Level 0 = prompt, proceed to *H. Check Relay Self-Tests*. If the relay will not exit SELBOOT, reattempt to upload the new firmware (beginning at *Step 1* under *G. Upload New Firmware*) or contact the factory-default for assistance.
Cannot communicate with relay via front-panel USB port.	From the **Call** menu of HyperTerminal, choose Disconnect and remove the USB cable from the front of the relay. Reinstall the cable and see *C. Establish Communications With the Relay*. See *Section 13: Testing and Troubleshooting* for additional troubleshooting tips.

H. Check Relay Self-Tests

The relay can display various self-test fail status messages. The troubleshooting procedures that follow depend upon the status message the relay displays.

Step 1.   Enter the **STATUS** command (**STA <Enter>**) at Access Level 1 to view relay status messages.

If the relay displays no fail status message, proceed to *I. Verify Relay Settings*.

If failures are displayed in the status message, proceed to *Solving Firmware Upgrade Issues*.

I. Verify Relay Settings

Step 1.   Use the **SHO** command to view the relay settings and verify that these match the settings you saved earlier (see *Backup Relay Settings and Other Data*).

If the settings do not match, reenter the settings you saved earlier.

J. Return the Relay to Service

Step 1.   Open the terminal window.

Step 2.   Follow *Step 2–Step 10* under *J. Return Relay to Service on page B.7*.

Method Three: Using a Web Browser

A. Set Port 5 Setting HTTPACC to 2

To upgrade firmware by using a web browser, the Port 5 setting HTTPACC must be set to 2. If this setting is set to 2, the FWFPC setting becomes available. FWFPC determines whether front-panel confirmation is required for firmware upgrades and defaults to Y. If FWFPC is set to N, the firmware upgrade process will take place without the need for front-panel confirmation. See *F. Upload New Firmware* for details on the front-panel confirmation process.

B. Obtain Firmware File

Follow instructions under *A. Obtain Firmware File on page B.3*.

C. Remove Relay From Service

Step 1.   If the relay is in use, follow your company practices for removing a relay from service. Typically, these include changing settings, or disconnecting external voltage sources or output contact wiring, to disable relay control functions.

Step 2. Apply ac power to the control.

Step 3. Establish an Ethernet connection to the device. See *Establishing Communications Using an Ethernet Port and Telnet or the Web Server on page 10.7* for more detailed instructions.

D. Establish Communications With the Relay

Establish communication between your personal computer and the relay by using a web browser. See *Using the Embedded Web Server (HTTP) on page 10.18* for more information. Establish a Telnet session with HyperTerminal (or an equivalent) using the TCP/IP connection, with the Host address and Port number set to match the Port 5 settings IPADDR (e.g., 192.168.1.2) and TPORT (e.g., 23), respectively.

E. Prepare the Relay (Save Relay Settings and Other Data)

Using the Telnet session, follow *D. Prepare the Relay (Save Relay Settings and Other Data) on page B.9*.

F. Upload New Firmware

NOTE: Access Level passwords are not encrypted in any way by the web server when logging in.

IMPORTANT NOTE: When upgrading firmware from R400 via the web server, to maintain user settings, upgrade to R401 first, then upgrade to the desired release (e.g., to upgrade from R400 to R4xx, upgrade from R400 to R401, and the upgrade from R401 to R4xx). Failure to comply will result in loss of user settings and default settings will be restored. Therefore, web server communication will be disabled (default setting EHTTP = N).

Step 1. To upload new firmware, log in to Access Level 2 of the web server. Select **2AC** from the Access Level drop-down box. Enter the respective **ACC** and **2AC** passwords and click the **Login** button.

Step 2. Once logged in verify communication with the correct control by checking the Relay Identifier (RID setting) and Terminal Identifier (TID setting). Choose **Firmware Upgrade** from the left pane, which will bring up the page shown in *Figure B.8*. This page also displays feedback from the previous firmware upgrades. If the prior firmware upgrade was successful, the page will display the message shown in *Figure B.8*. If the prior firmware upgrade failed, the page will display `Previous firmware upgrade failed. Date: xx/xx/xxxx Time: hh:mm:ss`, with an error message below. See *Solving Firmware Upgrade Issues* for possible error messages and their descriptions. If no prior firmware upgrade has occurred (which is the case for a new unit from the factory), the page will display `Previous firmware upgrade information is unavailable`.
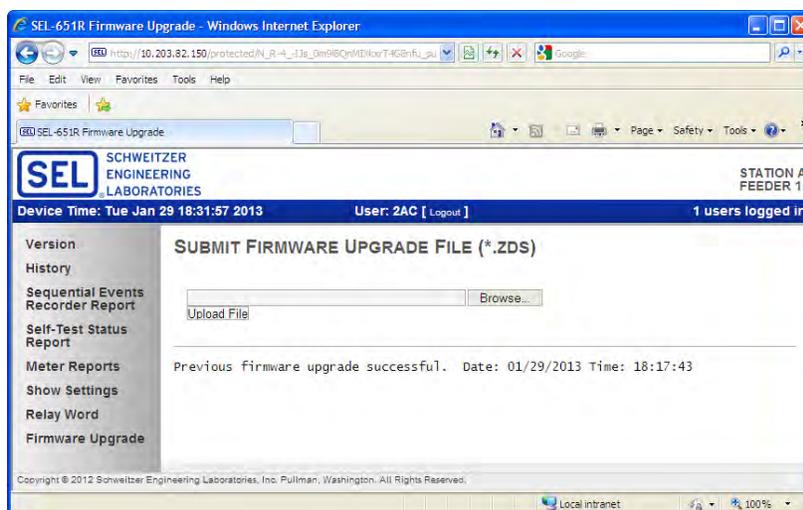
Figure B.8   Firmware Upload File Selection Page

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Method Three: Using a Web Browser

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Step 3. To search for your firmware file, click on the **Browse** button. The format of this file must be .zds.

Step 4. To submit, click **Upload File**. Once the upload has started, it cannot be canceled. During the upload process the control will remain enabled and continue normal operation.

Step 5. Once the firmware file is transferred to the device, the relay will attempt to restart using the new firmware. This process will complete in as fast as 45 seconds.

Step 6. If front-panel confirmation is enabled (setting FWFPC = Y) and the file upload is complete, the web server will display the message shown in *Figure B.8* and the following message will be displayed on the relay's LCD:

```
CONFIRM UPGRADE?
ESC = N; ENT = Y
```
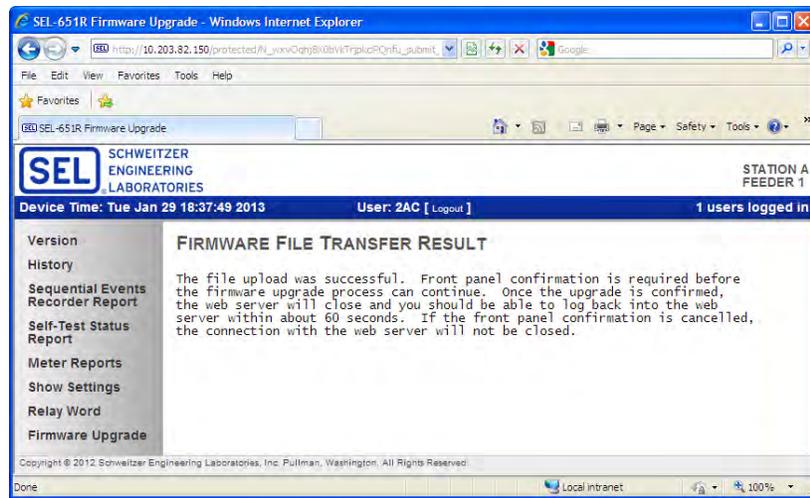

Figure B.9   Firmware Upgrade With Front-Panel Confirmation Required

a. Press the **ENT** button to confirm the firmware upgrade. Once front-panel confirmation is given, the HTTP session will close and the firmware upgrade will take place.

b. If front-panel confirmation is not given within 60 seconds, the message shown in *Figure B.9* will be displayed by the web server at the Firmware Upgrade page. The HTTP session will remain open and the firmware upgrade will not take place.

c. The control will remain enabled and in normal operation until the upgrade is confirmed via the front panel. If confirmation times out, the control will stay enabled and continue normal operation.

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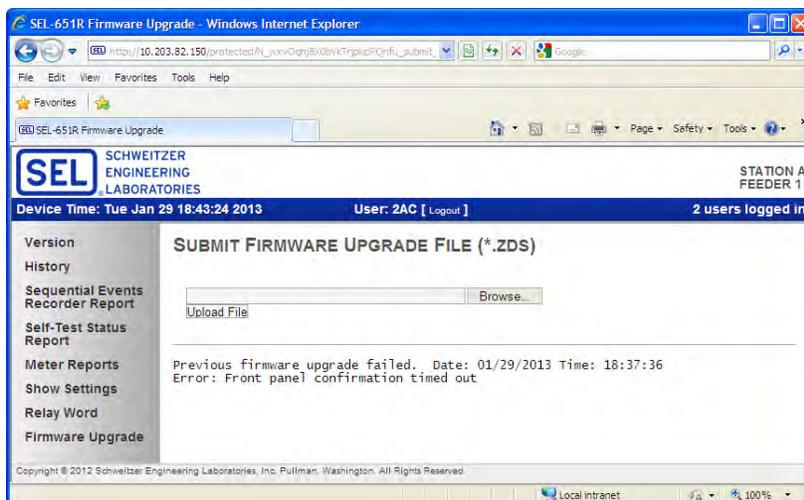
Figure B.10   Front-Panel Confirmation Time-Out Message

Step 7.   If front-panel confirmation is not enabled (FWFPC = N), the message shown in *Figure B.11* will be displayed by the web server. The HTTP session will close after the upload is complete and the firmware upgrade will take place.
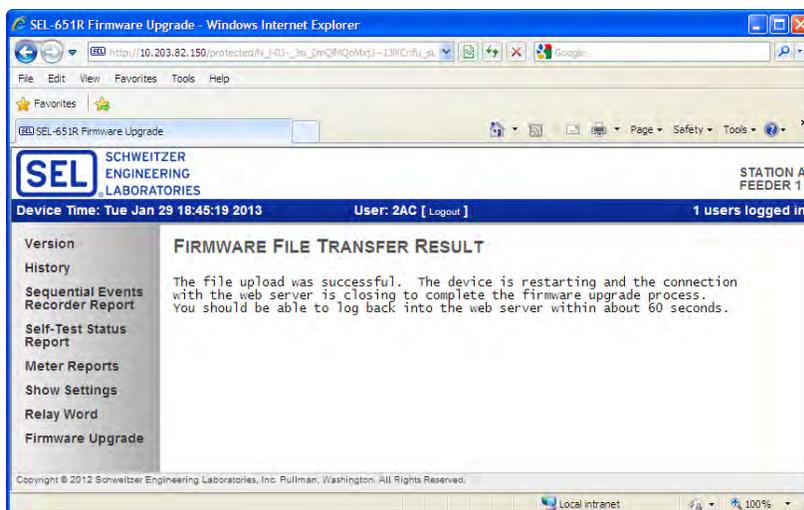
Figure B.11   Firmware Upgrade Without Front-Panel Confirmation Required

G. Check Relay Self-Tests

After the firmware upgrade is completed and once you have logged back in to Access Level 1 of the web server, you can check the relay self-tests by clicking **Self-Test Status Report** in the left pane. If the relay displays no fail status message, proceed to *H. Verify Relay Settings*. If failures are displayed in the status message, proceed to *Solving Firmware Upgrade Issues*.

H. Verify Relay Settings

To verify the settings are correct for your relay, click **Show Settings** in the left pane. Verify that these match the settings you saved earlier (see *Backup Relay Settings and Other Data on page B.9*). Note that Calibration settings are not viewable via the web server, a terminal connection will be needed to verify these settings. If the settings do not match, reenter the settings you saved earlier.

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Solving Firmware Upgrade Issues

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I. Return Relay to Service

Step 1. Begin a Telnet session by opening the terminal window. Type **telnet IPADDR**, where IPADDR is the Port 5 setting IPADDR (e.g., 192.168.1.2).

Step 2. Follow *Step 2–Step 10* under *J. Return Relay to Service on page B.7*.

Solving Firmware Upgrade Issues

If a `FAIL` message is returned in response to the **STA** command, perform the following steps.

Step 1. Use the **ACC** and **2AC** commands with the associated passwords to enter Access Level 2.

Step 2. Type **STA C <Enter>**. Answer **Y <Enter>** to the `Reboot the relay and clear status` prompt. The relay will respond with `Rebooting the relay`. Wait for about 30 seconds, then press **<Enter>** until you see the Access Level 0 = prompt.

Step 3. Use the **ACC** command with the associated password to enter Access Level 1.

Step 4. Type **STA <Enter>**.

If there are no fail messages and you are using Method One, click **Next** in Step 3 of 4 of the Firmware Loader and go to *I. Verify Relay Settings on page B.7*.

If there are no fail messages and you are using Method Two, go to *I. Verify Relay Settings on page B.14*.

If there are no fail messages and you are using Method Three, go to *H. Verify Relay Settings on page B.17*.

If there are fail messages, continue with *Step 5*.

Step 5. Use the **2AC** command with the associated password to enter Access Level 2.

Step 6. Type **R_S <Enter>** to restore factory-default settings in the relay.

The relay asks whether to restore default settings. If the relay does not accept the **R_S** command, contact SEL for assistance.

LOSS OF SETTINGS
Step 6 will cause the loss of settings and other important data. Be sure to retain relay settings and other data downloaded from the relay at the start of the firmware upgrade process.

Step 7. Type **Y <Enter>**.

The relay can take as long as two minutes to restore default settings. The relay then reinitializes and the **ENABLED** LED illuminates. Contact SEL for assistance if the relay does not enable.

Step 8. Press **<Enter>** to check for the Access Level 0 = prompt indicating that serial communication is successful.

Step 9. Use the **ACC** and **2AC** commands and type the corresponding passwords to reenter Access Level 2.

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Step 10. Type **SHO C <Enter>** to verify the relay calibration settings.

If using Method One and the settings do not match the settings contained in the text file you recorded in *D. Prepare the Relay (Save Relay Settings and Other Data) on page B.4*, contact SEL for assistance.

If using Method Two and the settings do not match the settings contained in the text file you recorded in *D. Prepare the Relay (Save Relay Settings and Other Data) on page B.9*, contact SEL for assistance.

Step 11. Use the **PAS** command to set the relay passwords.

Step 12. Restore the relay settings:

 a. If you have SEL-5010 Relay Assistant software or QuickSet, restore the original settings by following the instructions for the respective software.

 b. If you do not have the SEL-5010 Relay Assistant software or QuickSet, restore the original settings by issuing the necessary **SET *n*** commands.

Step 13. If any failure status messages still appear on the relay display, see *Section 13: Testing and Troubleshooting* or contact SEL for assistance.

If the firmware upgrade process fails, one of the error messages in *Table B.2* will be displayed on the **Firmware Upgrade** page accessible from the left pane of the web server.

Table B.2   Firmware Upgrade Process Error Messages

Error Message	Description
`Invalid digital signature`	The digital signature verification failed.
`Invalid firmware file`	The firmware file failed one of many possible integrity checks.
`Front panel confirmation canceled`	The user canceled the front-panel confirmation process.
`Front panel confirmation timed out`	The user did not confirm or cancel the firmware upgrade process before the time-out period expired.

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Appendix C

Compressed ASCII Commands

Overview

The SEL-651R-2 provides Compressed ASCII versions of some of the relay ASCII commands. The Compressed ASCII commands allow an external device to obtain data from the relay in a format that directly imports into spreadsheet or database programs and which can be validated with a checksum.

The SEL-651R-2 provides the following Compressed ASCII commands:

Command	Description
CASCII	Configuration message
CSTATUS	Status message
CHISTORY	History message
CHISTORY HIF[a]	HIF history message
CEVENT	Event message
CEVENT HIF[a]	HIF event message
CSUMMARY	Event summary message
CSUMMARY HIF[a]	HIF event summary message

[a] The relay must support Arc Sense technology for command to be available.

CASCII Command—General Format

The Compressed ASCII configuration message provides data for an external computer to extract data from other Compressed ASCII commands. To obtain the configuration message for the Compressed ASCII commands available in an SEL relay, type:

CAS <CR>

C.2 | Compressed ASCII Commands
CASCII Command—General Format

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The relay sends the following message:

```
<STX>"CAS",n,"yyyy"<CR><LF>
"COMMAND 1",ll,"yyyy"<CR><LF>
"#H","xxxxx","xxxxx",......,"xxxxx","yyyy"<CR><LF>
"#D","ddd","ddd","ddd","ddd",......,"ddd","yyyy"<CR><LF>
"COMMAND 2",ll,"yyyy"<CR><LF>
"#h","ddd","ddd",......,"ddd","yyyy"<CR><LF>
"#D","ddd","ddd","ddd","ddd",......,"ddd","yyyy"<CR><LF>
.
.
.
"COMMAND n",ll,"yyyy"<CR><LF>
"#H","xxxxx","xxxxx",......,"xxxxx","yyyy"<CR><LF>
"#D","ddd","ddd","ddd","ddd",......,"ddd","yyyy"<CR><LF><ETX>
```

where:

n	is the number of Compressed ASCII command descriptions to follow.
COMMAND	is the ASCII name for the Compressed ASCII command as sent by the requesting device. The naming convention for the Compressed ASCII commands is a C preceding the typical command. For example, **CSTATUS** (abbreviated to **CST**) is the compressed **STATUS** command.
ll	is the minimum access level at which the command is available.
#H	identifies a header line to precede one or more data lines; # is the number of subsequent ASCII names. For example, 21H identifies a header line with 21 ASCII labels.
#h	identifies a header line to precede one or more data lines; # is the number of subsequent format fields. For example, 8h identifies a header line with 8 format fields.
xxxxx	is an ASCII name for corresponding data on following data lines. Maximum ASCII name width is 10 characters.
#D	identifies a data format line; # is the maximum number of subsequent data lines.
ddd	identifies a format field containing one of the following type designators: I Integer data F Floating point data mS String of maximum m characters (e.g., 10S for a 10 character string)
yyyy	is the 4-byte hex ASCII representation of the checksum.

A Compressed ASCII command may require multiple header and data configuration lines.

If a Compressed ASCII request is made for data that are not available, (e.g., the history buffer is empty or invalid event request), the relay responds with the following message:

```
<STX>"No Data Available","yyyy"<CR><LF><ETX>
```

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Compressed ASCII Commands | c.3
CAS Command
Wolfe

CASCII Command

Display the SEL-651R-2 Compressed ASCII configuration message by sending:

CAS <CR>

If the relay does not support Arc Sense technology, the relay sends:

```
=>>CAS <Enter>
"CAS",6,"01A9"<CR>
"CST",1,"01B7"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"40H","I1_OS","I2_OS","I3_OS","IN_OS","I1_OSH","I2_OSH","I3_OSH","IN_OSH","V1Y_O
S","V2Y_OS","V3Y_OS","V1Z_OS","V2Z_OS","V3Z_OS","MOF","P5V_PS","P5V_REG","P15V_P
S","N15V_PS","P12V_TC","P5VA_PS","N5VA_PS","TEMP","RTC","HMI","RAM","ROM","ADC",
"FLASH","FPGA","EEPROM","INT_BRD","USB_BRD","COM_BRD","INPBV","12VAUX","CMODE","
VBAT","IBAT","TCCAPV","5329"<CR>
"1D","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S",
"9S","9S","9S","9S","9S","9S","9S","4S","4S","4S","4S","4S","4S","4S",
"4S","4S","4S","9S","9S","7S","F","F","9S","273A"<CR>
"CHI",1,"01A1"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"16H","REC_NUM","REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","EVENT"
,"LOCATION","CURR","FREQ","GROUP","SHOT","TRIP","TARGETS","2107"<CR>
"41D","I","I","I","I","I","I","I","I","I","6S","F","I","F","I","I","25S","0E
0D"<CR>
"CEV",1,"01AB"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"14H","REF_NUM","FREQ","SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT","LOCATION","
SHOT","TARGETS","IA","IB","IC","IG","3I2","1CEC"<CR>
"1D","F","I","I","I","I","6S","F","I","30S","I","I","I","I","I","0AF1"<CR>
"14H","IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)"
,"VCZ(kV)","FREQ","TRIG","EN TRIPLED * * * * * * TLED_08 TLED_07 TLED_06 TLED_05
"Names Of elements in the relay word separated by spaces"
","AE33"<CR>
"60D","F","F","F","F","F","F","F","F","F","F","F","F","2S","248S","0BF8"<CR>
"CEV C",1,"020E"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"14H","REF_NUM","FREQ","SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT","LOCATION","
SHOT","TARGETS","IA","IB","IC","IG","3I2","1CEC"<CR>
"1D","F","I","I","I","6S","F","I","30S","I","I","I","I","I","0AF1"<CR>
"14H","IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)"
,"VCZ(kV)","FREQ","TRIG","
"Names Of elements in the relay word separated by spaces"
","AE33"<CR>
"480D","F","F","F","F","F","F","F","F","F","F","F","F","2S","248S","0C2E"<CR>
"CEV R",1,"021D"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"14H","REF_NUM","FREQ","SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT","LOCATION","
SHOT","TARGETS","IA","IB","IC","IG","3I2","1CEC"<CR>
"1D","F","I","I","I","6S","F","I","30S","I","I","I","I","I","0AF1"<CR>
"14H","IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)"
,"VCZ(kV)","FREQ","TRIG","E
"Names Of elements in the relay word separated by spaces"
","AE33"<CR>
"512D","F","F","F","F","F","F","F","F","F","F","F","F","2S","248S","0C2A"<CR>
"CSU",1,"01B8"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"11H","REF_NUM","FREQ","EVENT","LOCATION","SHOT","TARGETS","IA","IB","IC","IG","
3I2","1356"<CR>
"1D","F","6S","F","I","30S","I","I","I","I","I","08C6"<CR>

=>>
```

C.4 | Compressed ASCII Commands
CASCII Command

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See *CEVENT Command on page C.6* for definition of the "*Names of elements in the relay word separated by spaces*" field.

If the relay supports Arc Sense technology, the relay sends:

```
<STX>
=>>CAS
"CAS",9,"01AC"<CR>
"CST",1,"01B7"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"40H","I1_OS","I2_OS","I3_OS","IN_OS","I1_OSH","I2_OSH","I3_OSH","IN_OSH","V1Y_O
S","V2Y_OS","V3Y_OS","V1Z_OS","V2Z_OS","V3Z_OS","MOF","P5V_PS","P5V_REG","P15V_P
S","N15V_PS","P12V_TC","P5VA_PS","N5V_PS","TEMP","RTC","HMI","RAM","ROM","ADC",
"FLASH","FPGA","EEPROM","INT_BRD","USB_BRD","COM_BRD","INPBV","12VAUX","CMODE","
VBAT","IBAT","TCCAPV","5329"<CR>
"1D","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S","9S",
"9S","9S","9S","9S","9S","9S","9S","9S","4S","4S","4S","4S","4S","4S","4S","4S",
"4S","4S","4S","9S","9S","7S","F","F","9S","273A"<CR>
"CHI",1,"01A1"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"17H","REC_NUM","REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","EVENT"
,"LOCATION","CURR","FREQ","GROUP","SHOT","TRIP","TARGETS","2108"
"40D","I","I","I","I","I","I","I","I","I","6S","F","I","F","I","I","I","25S","0E
0C"<CR>
"CEV",1,"01AB"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"14H","REF_NUM","FREQ","SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT","LOCATION","
SHOT","TARGETS","IA","IB","IC","IG","3I2","1CEC"<CR>
"1D","I","F","I","I","I","6S","F","I","30S","I","I","I","I","I","0BAA"<CR>
"14H","IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)"
,"VCZ(kV)","FREQ","TRIG","
"Names Of elements in the relay word separated by spaces",
"880F"<CR>
"60D","F","F","F","F","F","F","F","F","F","F","F","F","2S","272S","0BF5"<CR>
"CEV C",1,"020E"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"14H","REF_NUM","FREQ","SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT","LOCATION","
SHOT","TARGETS","IA","IB","IC","IG","3I2","1CEC"<CR>
"1D","I","F","I","I","I","6S","F","I","30S","I","I","I","I","I","0BAA"<CR>
"14H","IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)"
,"VCZ(kV)","FREQ","TRIG","
"Names Of elements in the relay word separated by spaces"
","880F"<CR>
"480D","F","F","F","F","F","F","F","F","F","F","F","F","2S","272S","0C2B"<CR>
"CEV R",1,"021D"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"14H","REF_NUM","FREQ","SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT","LOCATION","
SHOT","TARGETS","IA","IB","IC","IG","3I2","1CEC"<CR>
"1D","I","F","I","I","I","6S","F","I","30S","I","I","I","I","I","0BAA"<CR>
"14H","IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)"
,"VCZ(kV)","FREQ","TRIG","
"Names Of elements in the relay word separated by spaces"
"880F"<CR>
"512D","F","F","F","F","F","F","F","F","F","F","F","F","2S","272S","0C27"<CR>
"CSU",1,"01B8"<CR>
"1H","FID","022C"<CR>
"1D","45S","0211"<CR>
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"<CR>
"1D","I","I","I","I","I","I","I","05F4"<CR>
"11H","REF_NUM","FREQ","EVENT","LOCATION","SHOT","TARGETS","IA","IB","IC","IG","
3I2","1356"<CR>
"1D","F","6S","F","I","30S","I","I","I","I","I","08C6"<CR>
"CHI HIF",1,"0298"
"3H","RID","TID","FID","04CE"
"1D","30S","30S","45S","045D"
"13H","REC_NUM","REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC",
"EVENT","DOWNED CONDUCTOR","GRP","FREQ","1B06"
"29D","I","I","I","I","I","I","I","I","15S","3S","I","F","0B2E"
"CEV HIF",1,"02A2"
"1H","FID","022C"
"1D","45S","0211"
"7H","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0BB9"
"1D","I","I","I","I","I","I","I","05F4"
"8H","REC_NUM","REF_NUM","NUM_CH_A","NUM_CH_D","SAM/CYC_A","SAM/CYC_D",
```

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Compressed ASCII Commands c.5
CSTATUS Command

```
"NUM_OF_CYC","PRIM_VAL","1879"
"1D","I","I","I","I","F","F","I","3S","O6E4"
"20H","IARMS(A)","IBRMS(A)","ICRMS(A)","SDIA(A)","SDIB(A)","SDIC(A)",
"SDIAREF(A)","SDIBREF(A)","SDICREF(A)","dA(A)","dB(A)","dC(A)",,"T7CNTA",
"T7CNTB","T7CNTC","T8CNTA","T8CNTB","T8CNTC","TRIG",
"Digitals from HIF Event Reporting","74OF"
"38700D","F","F","F","F","F","F","F","F","F","F","F","F",,"I","I","I",
"I","I","I","1S","12S","1OAE"
"CSU HIF",1,"O2AF"
"3H","RID","TID","FID","O4CE"
"1D","3OS","3OS","45S","O45D"
"25H","REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","EVENT",
"HIF PHASE","DOWNED CONDUCTOR","FREQUENCY","BREAKER","IARMS_PF",
"IBRMS_PF","ICRMS_PF","IARMS","IBRMS","ICRMS",,"SDIA_PF","SDIB_PF",
"SDIC_PF","SDIA","SDIB","SDIC","3E97"
"1D","I","I","I","I","I","I","I","I","13S","5S","3S","F","6S","F","F",
"F","F","F","F","F","F","F","F","F","F","F","15EB"
=>>
```

CSTATUS Command

Display status data in Compressed ASCII format by sending:

CST <CR>

The relay responds:

```
<STX>"FID","yyyy"<CR>
"Relay FID string","yyyy"<CR>
"MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","yyyy"<CR>
xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,"yyyy"<CR>
"I1_OS","I2_OS","I3_OS","IN_OS","I1_OSH","I2_OSH","I3_OSH","IN_OSH",
"V1Y_OS","V2Y_OS","V3Y_OS","V1Z_OS","V2Z_OS","V3Z_OS","MOF",
"P5V_PS","P5V_REG","P15V_PS","N15V_PS","P12V_TC","P5VA_PS","N5VA_PS",
"TEMP","RTC","HMI","RAM","ROM","ADC","FLASH","FPGA","EEPROM","INT_BRD",
"USB_BRD","COM_BRD","INPBV","12VAUX","CMODE","VBAT","IBAT","TCCAPV",
"yyyy"<CR>
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx",
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx",
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx",
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx",xxxx,xxxx,"xxxx",
"yyyy"<CR><ETX>
```

where:

xxxx   are the data values corresponding to the first line labels

yyyy   is the 4-byte hex ASCII representation of the checksum

CHISTORY Command

Display history data in Compressed ASCII format by sending:

CHI [n]<CR>   (parameters in [] are optional)

The relay sends the following message:

```
<STX>"FID","yyyy"<CR>
"Relay FID string","yyyy"<CR>
"REC_NUM","REF_NUM","MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","EVENT",
"LOCATION","CURR","FREQ","GROUP","SHOT","TRIP","TARGETS","yyyy"<CR>
xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,"xxxx",xxxx,xxxx,xxxx,xxxx,
ssss,xxxx"xxxx","yyyy"<CR><ETX>
```

where:

xxxx   are the data values corresponding to the first line labels

yyyy   is the 4-byte hex ASCII representation of the checksum

ssss   the highest phase shot counter

C.6 | Compressed ASCII Commands
CEVENT Command

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If the history buffer is empty, the relay responds:

```
<STX>"No Data Available","0668"<CR><LF><ETX>
```

Parameter *n* is an optional numeric parameter that specifies the number of records to return. If *n* is less than or equal to the number of records available in the history, the relay returns *n* records.

CHISTORY HIF Command (Only Available in Relays That Support Arc Sense Technology)

Display HIF history data in Compressed ASCII format by sending:

CHI HIF [n] <CR> (parameters in [] are optional)

Refer to *HIF Event History on page 12.51* for details on the **CHI HIF** command.

If the specified event does not exist, the relay responds:

```
<STX>"No Data Available","0668"<CR><LF><ETX>
```

CEVENT Command

Display event report in Compressed ASCII format by sending:

CEV [*n* S*x* L*y* L R C P]   (parameters in [ ] are optional)

where:

n	is event number or unique event identification number, defaults to 1
S*x*	is *x* samples per cycle (4, 16, 32, or 128); defaults to 4. If the S*x* parameter is present, it overrides the L parameter. S128 must be accompanied by the R parameter (**CEV S128 R**)
L*y*	is *y* cycles event report length (1 to LER) for filtered event reports, (1 to LER + 1) for raw event reports; defaults to LER if not specified. Raw reports always contain one extra cycle of data, except for raw reports with S128 parameter, which contain two extra cycles of data.
L	is 32 samples per cycle; overridden by the S*x* parameter, if present
R	specifies raw (unfiltered) data; defaults to 32 samples per cycle unless overridden by the S*x* parameter. Defaults to LER + 1 cycles in length unless overridden with the L*y* parameter.
C	specifies 16 samples per cycle analog data, 4 samples per cycle digital data, LER-cycle length, unless overridden by the S*x*, L*y*, L, or R parameters.
P	precise to synchrophasor-level accuracy for signal content at nominal frequency. This option is available when TSOK = logical 1 when the event report was triggered.

The relay responds to the **CEV** command with the *n*th event report as shown below.

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C.7 Event command
Wolfe

```
<STX>"FID","yyyy"<CR>
"Relay FID string","yyyy"<CR>
"MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","yyyy"<CR>
xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,"yyyy"<CR>
"REF_NUM","FREQ", "SAM/CYC_A","SAM/CYC_D","NUM_OF_CYC","EVENT",
"LOCATION","SHOT","TARGETS","IA","IB","IC","IG","3I2","yyyy"<CR>
xxxx,xxxx,xxxx,xxxx,xxxx,"xxxx",xxxx,xxxx,"xxxx",xxxx,xxxx,xxxx,xxxx,xxxx,
"yyyy"<CR>
"IA","IB","IC","IN","IG","VAY(kV)","VBY(kV)","VCY(kV)","VAZ(kV)","VBZ(kV)",
"VCZ(kV)","FREQ",
"TRIG", "Names of elements in the relay word separated by spaces","yyyy "<CR>
xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,xxxx,z,
"HEX-ASCII Relay Word","yyyy"<CR>
"Analog and digital data repeated for each row of event report"
"SETTINGS","yyyy"<CR>
"Relay group, logic, global, and report settings, and Part Number as displayed
with the SHO command or PAR command (surrounded by quotes)","yyyy"<CR>
<ETX>
```

where:

xxxx	are the data values corresponding to the line labels
yyyy	is the 4-byte hex ASCII representation of the checksum
REF_NUM	is the unique identification number
FREQ	is the power system frequency at the trigger instant
SAM/CYC_A	is the number of analog data samples per cycle
SAM/CYC_D	is the number of digital data samples per cycle
NUM_OF_CYC	is the number of cycles of data in the event report
EVENT	is the event type
LOCATION	is the fault location
SHOT	is the recloser shot counter
TARGETS	are the front-panel tripping targets
IA, IB, IC, IG, 3I2	is the fault current
TRIG	refers to the trigger record
z	is ">" for the trigger row, "*" for the fault current row and empty for all others. If the trigger row and fault current row are the same, both characters are included (e.g., ">*")
HEX-ASCII Relay Word	is the hex ASCII format of the Relay Word. The first element in the Relay Word is the most significant bit in the first character.

For filtered events, if samples per cycle are specified as 16, the analog data are displayed at 1/16-cycle intervals and digital data at 1/4-cycle intervals.

If samples per cycle are specified as 32, the analog data are displayed at 1/32-cycle intervals and digital data are displayed at 1/4-cycle intervals.

For raw events, both analog and digital data are displayed at the interval specified by the Sx parameter. Digital data are updated every 1/4 cycle. Optoisolated inputs IN101–IN107 and IN201–IN206 are updated every 1/16 cycle.

The digital data are displayed as a series of hex ASCII characters. The relay displays digital data only when they are available. When no data are available, the relay sends only the comma delimiter in the digital data field.

C.8 Compressed ASCII Commands
CEVENT Command

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If the specified event does not exist, the relay responds:

```
<STX>"No Data Available","0668"<CR><LF><ETX>
```

The "Names of elements in the Relay Word separated by spaces" field is shown in the example below.

```
EN TRIPLED * * * * * * TLED_08 TLED_07 TLED_06 TLED_05 TLED_04 TLED_03 TLED_02
TLED_01 TLED_16 TLED_15 TLED_14 TLED_13 TLED_12 TLED_11 TLED_10 TLED_09 TLED_24
TLED_23 TLED_22 TLED_21 TLED_20 TLED_19 TLED_18 TLED_17 50A1 50B1 50C1 50P1 50A2 50B2
50C2 50P2 50A3 50B3 50C3 50P3 50A4 50B4 50C4 50P4 50G1 50G2 50G3 50G4 50Q1 50Q2 50Q3
50Q4 50N1 50N2 50N3 50N4 50A 50B 50C 50P32 50P5 50P6 50G5 50G6 50Q5 50Q6 50N5 50N6
50LA 50LB 50LC 50L 50GF 50GR 50QF 50QR 51AS 51AR 51A 51AT 51BS 51BR 51B 51BT 51CS
51CR 51C 51CT 51PS 51PR 51P 51PT 51G1S 51G1R 51G1 51G1T 51G2S 51G2R 51G2 51G2T 51QS
51QR 51Q 51QT 51N1S 51N1R 51N1 51N1T 50A1T 50B1T 50C1T 50P1T 50A2T 50B2T 50C2T 50P2T
50A3T 50B3T 50C3T 50P3T 50A4T 50B4T 50C4T 50P4T 50G1T 50G2T 50G3T 50G4T 50Q1T 50Q2T
50Q3T 50Q4T 50N1T 50N2T 50N3T 50N4T 51N2S 51N2R 51N2 51N2T 52AA 52AB 52AC 52A3P SPOA
SPOB SPOC SPO V1GOOD LOP VPOLV GNDSW DD SPE SW1 3PO FSA FSB FSC * PHASE_A PHASE_B
PHASE_C * ZLOUT ZLIN ZLOAD * FAULT * * * 27YA1 27YB1 27YC1 27YA2 27YB2 27YC2 59YA1
59YB1 59YC1 59YA2 59YB2 59YC2 27YAB1 27YBC1 27YCA1 59YAB1 59YBC1 59YCA1 59YN1 59YN2
59YQ1 59YV1 3P27Y 3P59Y * * * * * * * VSELY 27ZA1 27ZB1 27ZC1 27ZA2 27ZB2 27ZC2 59ZA1
59ZB1 59ZC1 59ZA2 59ZB2 59ZC2 27ZAB1 27ZBC1 27ZCA1 59ZAB1 59ZBC1 59ZCA1 59ZN1 59ZN2
59ZQ1 59ZV1 3P27Z 3P59Z * * * * * * * VSELZ SF 25A1 25A2 SFAST SSLOW * 59VS 59VP 81D1
81D2 81D3 81D4 81D5 81D6 FREQOK * 81D1T 81D2T 81D3T 81D4T 81D5T 81D6T 27B81 * * IN107
IN106 IN105 IN104 IN103 IN102 IN101 * * IN206 IN205 IN204 IN203 IN202 IN201 * * *
81R4T 81R3T 81R2T 81R1T 81RT * * PB06_LED PB05_LED PB04_LED PB03_LED PB02_LED
PB01_LED * * PB12_LED PB11_LED PB10_LED PB09_LED PB08_LED PB07_LED PWR_SRC1 * DISTST
CHRGG DISCHG DTFAIL BTFAIL TOSLP * TCCAP XS_TRIP1 XS_TRIP2 XS_TRIP3 XS_CLOS1 XS_CLOS2
XS_CLOS3 LB01 LB02 LB03 LB04 LB05 LB06 LB07 LB08 LB09 LB10 LB11 LB12 LB13 LB14 LB15
LB16 CCA CCB CCC CC3 OCA OCB OCC OC3 SOTFE SOTFT TRGTR * TRIPA TRIPB TRIPC TRIP3P
LT01 LT02 LT03 LT04 LT05 LT06 LT07 LT08 LT09 LT10 LT11 LT12 LT13 LT14 LT15 LT16 LT17
LT18 LT19 LT20 LT21 LT22 LT23 LT24 LT25 LT26 LT27 LT28 LT29 LT30 LT31 LT32 SV01 SV02
SV03 SV04 SV01T SV02T SV03T SV04T SV05 SV06 SV07 SV08 SV05T SV06T SV07T SV08T SV09
SV10 SV11 SV12 SV09T SV10T SV11T SV12T SV13 SV14 SV15 SV16 SV13T SV14T SV15T SV16T
SV17 SV18 SV19 SV20 SV17T SV18T SV19T SV20T SV21 SV22 SV23 SV24 SV21T SV22T SV23T
SV24T SV25 SV26 SV27 SV28 SV25T SV26T SV27T SV28T SV29 SV30 SV31 SV32 SV29T SV30T
SV31T SV32T SV33 SV34 SV35 SV36 SV33T SV34T SV35T SV36T SV37 SV38 SV39 SV40 SV37T
SV38T SV39T SV40T SV41 SV42 SV43 SV44 SV41T SV42T SV43T SV44T SV45 SV46 SV47 SV48
SV45T SV46T SV47T SV48T SC01QU SC02QU SC03QU SC04QU SC05QU SC06QU SC07QU SC08QU
SC01QD SC02QD SC03QD SC04QD SC05QD SC06QD SC07QD SC08QD SC09QU SC10QU SC11QU SC12QU
SC13QU SC14QU SC15QU SC16QU SC09QD SC10QD SC11QD SC12QD SC13QD SC14QD SC15QD SC16QD
79RS3P 79CY3P 79LO3P SHO3P SH13P SH23P SH33P SH43P 79RSA 79CYA 79LOA SHOA SH1A SH2A
SH3A SH4A 79RSB 79CYB 79LOB SHOB SH1B SH2B SH3B SH4B 79RSC 79CYC 79LOC SHOC SH1C SH2C
SH3C SH4C CLOSEA CLOSEB CLOSEC CLOSE3P CFA CFB CFC CF3P RCSFA RCSFB RCSFC RCSF3P
OPTMNA OPTMNB OPTMNC OPTMN3P RSTMNA RSTMNB RSTMNC RSTMN3P ULCLA ULCLB ULCLC ULCL3P
32QE 32QGE 32VE * F32Q R32Q F32QG R32QG F32V R32V F32P R32P * * * * 32QF 32QR 32GE
32GR 32PF 32PR * * BCWA BCWB BCWC BCW PDEM NDEM GDEM QDEM OUT108 OUT107 OUT106 OUT105
OUT104 OUT103 OUT102 OUT101 OUT202 OUT201 RCCL3X RCTR3X RCCL2X RCTR2X RCCL1X RCTR1X
* * * * * * * * SG1 SG2 SG3 SG4 SG5 SG6 SG7 SG8 * * * IRIGOK INMET ICMET IBMET IAMET
RMB8A RMB7A RMB6A RMB5A RMB4A RMB3A RMB2A RMB1A TMB8A TMB7A TMB6A TMB5A TMB4A TMB3A
TMB2A TMB1A RMB8B RMB7B RMB6B RMB5B RMB4B RMB3B RMB2B RMB1B TMB8B TMB7B TMB6B TMB5B
TMB4B TMB3B TMB2B TMB1B LBOKA CBADA RBADA ROKA LBOKB CBADB RBADB ROKB SAGA SAGB SAGC
SAG3P SWA SWB SWC SW3P * * * * * * * * INTA INTB INTC INT3P * * * TESTDB * * * 3PWR1
* * * 3PWR2 * * * 3PWR3 * * * 3PWR4 * * PB06 PB05 PB04 PB03 PB02 PB01 * * PB06_PUL
PB05_PUL PB04_PUL PB03_PUL PB02_PUL PB01_PUL * * PB12 PB11 PB10 PB09 PB08 PB07 * *
PB12_PUL PB11_PUL PB10_PUL PB09_PUL PB08_PUL PB07_PUL RB01 RB02 RB03 RB04 RB05 RB06
RB07 RB08 RB09 RB10 RB11 RB12 RB13 RB14 RB15 RB16 RB17 RB18 RB19 RB20 RB21 RB22 RB23
RB24 RB25 RB26 RB27 RB28 RB29 RB30 RB31 RB32 RSTTRGT RST_MML RST_ENE RST_HIS RST_BK
RST_PDM RST_DEM RST_HAL * LINK5A LINK5B LNKFAIL P5ASEL P5BSEL TSNTPP TSNTPB SV49 SV50
SV51 SV52 SV49T SV50T SV51T SV52T SV53 SV54 SV53T SV54T SV55T SV56T SV57
SV58 SV59 SV60 SV57T SV58T SV59T SV60T SV61 SV62 SV63 SV64 SV61T SV62T SV63T SV64T
DST DSTP LPSEC LPSECP TQUAL4 TQUAL3 TQUAL2 TQUAL1 TSOK TIRIG PMDOK PMTRIG TREA4 TREA3
TREA2 TREA1 SALARM ACCESS * * HALARMA HALARMP HALARML HALARM * * PASNVAL ACCESSP
GRPSW SETCHG CHGPASS BADPASS VB001 VB002 VB003 VB004 VB005 VB006 VB007 VB008 VB009
VB010 VB011 VB012 VB013 VB014 VB015 VB016 VB017 VB018 VB019 VB020 VB021 VB022 VB023
VB024 VB025 VB026 VB027 VB028 VB029 VB030 VB031 VB032 VB033 VB034 VB035 VB036 VB037
VB038 VB039 VB040 VB041 VB042 VB043 VB044 VB045 VB046 VB047 VB048 VB049 VB050 VB051
VB052 VB053 VB054 VB055 VB056 VB057 VB058 VB059 VB060 VB061 VB062 VB063 VB064 VB065
VB066 VB067 VB068 VB069 VB070 VB071 VB072 VB073 VB074 VB075 VB076 VB077 VB078 VB079
VB080 VB081 VB082 VB083 VB084 VB085 VB086 VB087 VB088 VB089 VB090 VB091 VB092 VB093
VB094 VB095 VB096 VB097 VB098 VB099 VB100 VB101 VB102 VB103 VB104 VB105 VB106 VB107
VB108 VB109 VB110 VB111 VB112 VB113 VB114 VB115 VB116 VB117 VB118 VB119 VB120 VB121
VB122 VB123 VB124 VB125 VB126 VB127 VB128 * * * * * * * * * * * * * * * * * * * *
* * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * *
* * * * * * * * HBL2AT HBL2BT HBL2CT HBL2T * * * * * * * * * * * * * * * * * * *
RSTDNPE
```

These names are listed in *Table F.1* and *Table F.2*.

An example of a portion of a *HEX-ASCII Relay Word* is shown below:

C0014000000000000000444C0000000000000E1100000000000100000
000000002003800202180400000000000000000004000000000000000000
00000008000002200000000000010000000000004000800F0000000000000
000000000000000000000000000000000000000F000000000000000000000
00000000000000000

Each bit in the *HEX-ASCII Relay Word* reflects the status of a Relay Word bit. The order of the labels in the "*Names of elements in the relay word separated by spaces*" field matches the order of the *HEX-ASCII Relay Word*. In the example above, the eleventh byte in the *HEX-ASCII Relay Word* is "44." In binary, this evaluates to 01000100. Mapping the labels to the bits yields:

Table C.1   Mapping Labels to Bits

Labels	51AS	51AR	51A	51AT	51BS	51BR	51B	51BT
Bits	0	1	0	0	0	1	0	0

In this example, the 51AR and 51BR elements are asserted (logical 1); all others are deasserted (logical 0).

CEVENT HIF Command (Only Available in Relays That Support Arc Sense Technology)

Display the HIF event report in Compressed ASCII format by sending:

CEV HIF [*n*]

where:

    n displays the HIF event report with the corresponding event number from the **HIS HIF** command.

The relay responds to the **CEV HIF** command with the *n*th HIF event report.

Refer to *HIF Event Reporting on page 12.52* for details on the **CEV HIF** command.

If the specified event does not exist, the relay responds:

```
<STX>"No Data Available","0668"<CR><LF><ETX>
```

CSU Command

Display summary event reports in Compressed ASCII format by sending:

CSU [*n*]

where:

No parameters outputs the newest chronological event summary

    n displays event summary with this corresponding number in the **HIS** command.

C.10 | Compressed ASCII Commands
CSU Command

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The relay responds to the **CSU** command with the *n*th long summary event report as shown in the example below:

```
<STX>"FID","0143"<CR>
"FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","0955"<CR>
"MONTH","DAY","YEAR","HOUR","MIN","SEC","MSEC","0ACA"<CR>
9,29,2011,8,15,1,500,"0400"<CR>
"REF_NUM","FREQ","EVENT","LOCATION","SHOT","TARGETS","IA","IB","IC","IG","3I2",
   "0FA0"<CR>
11675,50.02,"TRIP",$$$$$.$$,3,"11 100000000000 001000000000",2,2,2,6,0,
"0BBF"<CR><ETX>
```

If the specified event does not exist, the relay responds:

```
<STX>"No Data Available","0668"<CR><ETX>
```

CSUMMARY HIF Command (Only Available in Relays That Support Arc Sense Technology)

Display the HIF summary report in Compressed ASCII format by sending:

CSU HIF [*n*]

where:

No parameters outputs the newest chronological event summary

n displays the event summary with the corresponding number in the **HIS HIF** command.

The relay responds to the **CSU HIF** command with the *n*th HIF long summary event report.

Refer to *HIF Event Summary on page 12.48* for details on the **CSU HIF** command.

If the specified event does not exist, the relay responds:

```
<STX>"No Data Available","0668"<CR><ETX>
```

Appendix D

MIRRORED BITS Communications

Overview

MIRRORED BITS communications is a direct relay-to-relay communications protocol that allows protective relays to exchange information quickly and securely and with minimal expense. Use MIRRORED BITS communications for remote control and remote sensing or communications-assisted protection schemes.

SEL products support several variations of MIRRORED BITS communications protocols. Through port settings, you can set the SEL-651R-2 Recloser Control for compatible operation with all SEL devices that communicate MIRRORED BITS. These devices use MIRRORED BITS communications to exchange the states of eight logic bits.

The PROTO := MBc option (c = A or B) is provided for compatibility with older SEL products that only support this version of MIRRORED BITS. Use the RTSCTS := MBT option if your application includes Pulsar MBT9600 modems. Use PROTO = MB8c if each relay supports this MIRRORED BITS version.

SEL Application Guide *AG2002-23, Applying Two SEL-351S Relays to Provide Automatic Source Transfer for Critical Loads*, provides an example of how to use MIRRORED BITS in the SEL-351S Relay. These same principles may be used with the SEL-651R-2.

Figure D.1 shows this example with the SEL-651R-2.
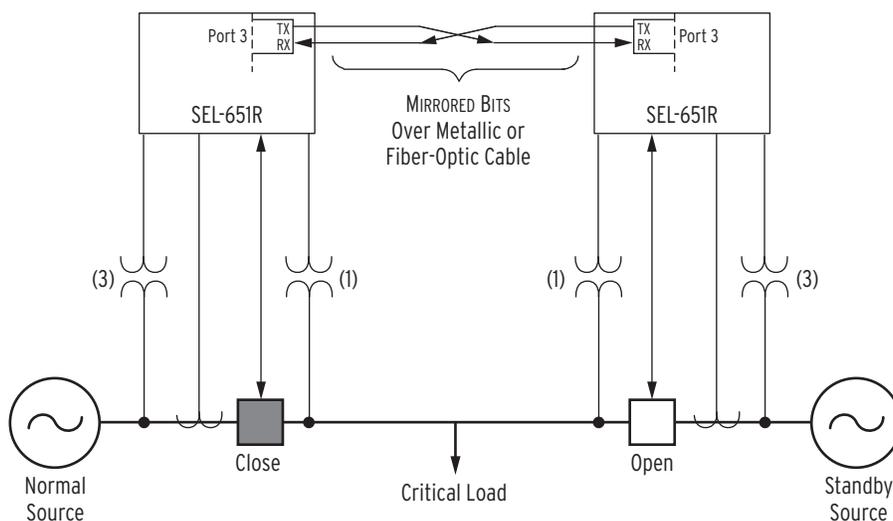
Figure D.1   Automatic Source Transfer Application

D.2 | MIRRORED BITS Communications
Communications Channels and Logical Data Channels

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Communications Channels and Logical Data Channels

The SEL-651R-2 supports two MIRRORED BITS communications channels, designated A and B. Use the port setting PROTO to assign one of the MIRRORED BITS communications channels to a serial port; PROTO := MBA for MIRRORED BITS communications Channel A or PROTO := MBB for MIRRORED BITS communications Channel B.

Transmitted bits include TMB1A–TMB8A and TMB1B–TMB8B. The last letter (A or B) designates with which channel the bits are associated. These bits are controlled by SELOGIC control equations. Received bits include RMB1A–RMB8A and RMB1B–RMB8B. You can use received bits as operands in SELOGIC control equations. The channel status bits are ROKA, RBADA, CBADA, LBOKA, ROKB, RBADB, CBADB, and LBOKB. You can also use these bits as operands in SELOGIC control equations. Use the **COM** command for additional channel status information.

Within each MIRRORED BITS communications message for a given channel (A or B), there are eight logical data channels (1–8). In operation compatible with other SEL products, you can use the eight logical data channels for TMB1–TMB8, as shown in *Figure D.2*.
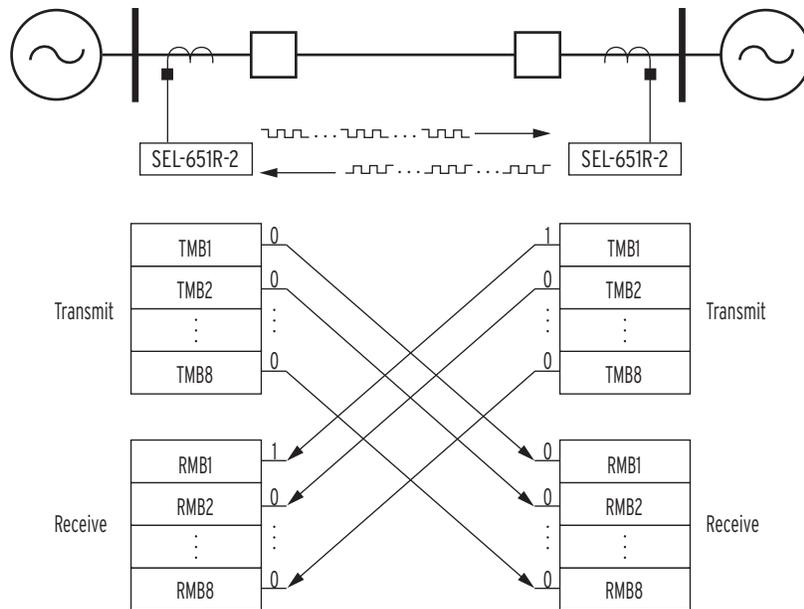
Figure D.2   Relay-to-Relay Logic Communication

Operation

Message Transmission

Depending on the settings, the SEL-651R-2 transmits a MIRRORED BITS communications message every 1/4 to 1/2 of an electrical cycle (see *Table D.2*). Each message contains the most recent values of the transmit bits. All messages are transmitted without idle bits between characters. Idle bits are allowed between messages.

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MIRRORED BITS Communications D.3
operation
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Message Reception

When the devices are synchronized and the MIRRORED BITS communications channel is in a normal state, the relay decodes and checks each received message. If the message is valid, the relay sends each received logic bit (RMBnc, where n = 1–8, c = A or B) to the corresponding pickup and dropout security counters, that in turn set or clear the RMBnc relay element bits.

Message Decoding and Integrity Checks

The relay provides indication of the status of each MIRRORED BITS communications channel, with element bits ROKA and ROKB. During normal operation, the relay sets the ROKc bit. The relay clears the bit upon detecting any of the following conditions:

➤ Parity, framing, or overrun errors.

➤ Receive data redundancy error.

➤ Receive message identification error.

➤ No message received in the time three messages have been sent.

The relay will assert ROKc only after successful synchronization as described below and two consecutive messages pass all of the data checks described above. After ROKc is reasserted, received data may be delayed while passing through the security counters described below.

While ROKc is not set, the relay does not transfer new RMB data to the pickup-dropout security counters described below. Instead, the relay sends one of the user-definable default values to the security counter inputs. For each RMBn, specify the default value with setting RXDFLT, as follows:

➤ 1

➤ 0

➤ X (to use the last valid value)

NOTE: When MIRRORED BITS serial port settings are changed, the received MIRRORED BITS reset to zero regardless of the RXDFLT setting.

Pickup/dropout security counters supervise the transfer of received data to RMB1c–RMB8c. Set these counters between 1 (allow every occurrence to pass) and at least 8 (require eight consecutive occurrences to pass). The pickup and dropout security count settings are separate.

The bit error rate of the MIRRORED BITS communications channel meets IEC-834-1 recommendations for direct tripping when the security counter (debounce) is set to 2 and can be further improved by increasing the message debounce.

A pickup/dropout security counter operates identically to a pickup/dropout timer, except that the counter uses units of "counted received messages," instead of time. An SEL-651R-2 communicating with another SEL-651R-2 sends and receives MIRRORED BITS messages four times per power system cycle. Therefore, a security counter set to two counts will delay a bit by about 1/2 power system cycle. You must consider the impact of the security counter settings in the receiving device to determine the channel timing performance.

Things become slightly more complicated when two relays of different processing rates are connected via MIRRORED BITS (for instance, an SEL-321 talking to an SEL-651R-2). The SEL-321 processes power system information each 1/8 power system cycle but processes the pickup/dropout security counters as messages are received. Because the SEL-321 is receiving messages from the SEL-651R-2, it will receive a message each 1/4 cycle processing interval. So, a counter set to two will again delay a bit by about 1/2 cycle. However, in that same example, a security counter set to two on the SEL-651R-2 will delay a bit by 1/4 cycle, because the SEL-651R-2 is receiving new MIRRORED BITS messages each 1/8 cycle from the SEL-321.

D.4 | MIRRORED BITS Communications
Operation

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Channel Synchronization

When an SEL-651R-2 detects a communications error, it deasserts ROKA or ROKB. If a node detects two consecutive communications errors, it transmits an attention message, which includes its TXID setting.

When a node receives an attention message, it checks to see if its TXID is included.

If its own TXID is included and at least one other TXID is included, the node transmits data.

If its own TXID is not included, the node deasserts ROKc, includes its TXID in the attention message, and transmits the new attention message.

If its own TXID is the only TXID included, the relay assumes the message is corrupt unless the loopback mode has been enabled. If loopback is not enabled, the node deasserts ROKc and transmits the attention message with its TXID included. If loopback is enabled, the relay transmits data.

In summary, when a node detects two consecutive errors, it transmits attention until it receives an attention with its own TXID included. If three or four relays are connected in a ring topology, then the attention message will go all the way around the loop, and eventually will be received by the originating node. It will then be killed and data transmission will resume. This method of synchronization allows the relays to determine reliably which byte is the first byte of the message. It also forces mis-synchronized UARTs to become re-synchronized. On the down side, this method takes down the entire loop for a receive error at any node in the loop. This decreases availability. It also makes one-way communications impossible.

Loopback Testing

Use the **LOOP** command to enable loopback testing. While in loopback mode, ROKc is deasserted, and LBOKc asserts and deasserts based on the received data checks.

Channel Monitoring

Based on the results of data checks described above, the relay will collect information regarding the 255 most recent communications errors. Each record contains at least the following fields:

➤ Dropout Time/Date

➤ Pickup Time/Date

➤ Time elapsed during dropout

➤ Reason for dropout (see *Message Decoding and Integrity Checks*)

Use the **COM** command to generate a long or summary report of the communications errors.

There is a single record for each outage, but an outage can evolve. For example, the initial cause could be a data disagreement, but framing errors can extend the outage. If the channel is presently down, the **COM** record will only show the initial cause, but the **COM** summary will display the present cause of failure.

When the duration of an outage on Channel A or B exceeds a user-definable threshold, the relay will assert a user-accessible flag, RBADA or RBADB.

When channel unavailability exceeds a user-settable threshold, the relay will assert a user-accessible flag, hereafter called CBADc (where c = A or B).

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MIRRORED BITS Communications   D.5
MIRRORED BITS Protocol for the Pulsar 9600 Bps Modem
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MIRRORED BITS Protocol for the Pulsar 9600 Bps Modem

Setting RTSCTS := MBT indicates that a Pulsar MBT modem is connected. When the user selects MBT, the data rate setting must be set to 9600 bps.

The MIRRORED BITS protocol compatible with the Pulsar MBT-9600 modem is identical to the standard MIRRORED BITS protocol with the following exceptions:

➤ The relay injects a delay (idle time) between messages.

➤ The length of the delay is one relay processing interval.

➤ The relay resets RTS (to a negative voltage at the EIA-232 connector).

➤ The relay sets RTS (to a positive voltage at the EIA-232 connector) for MIRRORED BITS communications that use the R6 or original R version of MIRRORED BITS.

➤ The relay monitors the CTS signal of the EIA-232 connector, which the modem will deassert if the channel has too many errors.

Settings

The SEL-651R-2 port settings associated with MIRRORED BITS communications are shown in *Table D.1*. Set PROTO = MBA to enable the MIRRORED BITS communications protocol Channel A on this port. Set PROTO = MBB to enable the MIRRORED BITS communications protocol Channel B on this port.

Table D.1   MIRRORED BITS (Sheet 1 of 2)

Name	Description	Range	Default
PROTO	Protocol	SEL, DNP, MBA, MBB, MB8A, MB8B	SEL (Need to set to one of the MB_ values for MIRRORED BITS communications)
SPEED	Data Rate	300, 1200, 2400, 4800, 9600, 19200, 38400, 57600	9600 (see *Table D.2*)
RTSCTS	Enable Hardware Handshaking	Y, N, MBT	N
TXID	MIRRORED BITS Transmit Identifier	1–4	2
RXID	MIRRORED BITS Receive Identifier	1–4	1
RBADPU	MIRRORED BITS RX Bad Pickup Time	1–10000 s	60
CBADPU	PPM MIRRORED BITS Channel Bad Pickup	1–10000	1000
RXDFLT	MIRRORED BITS Receive Default State	8 character string of 1s, 0s, or Xs	XXXXXXXX
RMB1PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB1DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1
RMB2PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB2DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1
RMB3PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB3DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1

D.6 MIRRORED BITS Communications
Settings

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Table D.1 MIRRORED BITS (Sheet 2 of 2)

Name	Description	Range	Default
RMB4PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB4DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1
RMB5PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB5DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1
RMB6PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB6DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1
RMB7PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB7DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1
RMB8PU	MIRRORED BITS RMB_ Pickup Debounce Msgs	1–8	1
RMB8DO	MIRRORED BITS RMB_ Dropout Debounce Msgs	1–8	1

As a function of the settings for SPEED, the message transmission periods are shown in *Table D.2*.

Table D.2 Message Transmission Periods

SPEED	SEL-651R-2
57600	1 message per 1/4 cycle
38400	1 message per 1/4 cycle
19200	1 message per 1/4 cycle
9600	1 message per 1/4 cycle
4800	1 message per 1/2 cycle

Use the RBADPU setting to determine how long a channel error must last before the relay element RBADA is asserted. RBADA is deasserted when the channel error is corrected. RBADPU is accurate to ±1 second.

Use the CBADPU setting to determine the ratio of channel downtime to the total channel time before the relay element CBADA is asserted. The times used in the calculation are those that are available in the **COMM** records. See the *COM Command (Communication Data) on page 10.44* for a description of the **COMM** records.

Set the RXID of the local relay to match the TXID of the remote relay. For example, in the three-terminal case, where Relay X transmits to Relay Y, Relay Y transmits to Relay Z, and Relay Z transmits to Relay X:

	TXID	RXID
Relay X	1	3
Relay Y	2	1
Relay Z	3	2

NOTE: When MIRRORED BITS serial port settings are changed, the received MIRRORED BITS reset to zero regardless of the RXDFLT setting.

Use the RXDFLT setting to determine the default state the MIRRORED BITS should use in place of received data if an error condition is detected. The setting is a mask of 1s, 0s and/or *X*s, for RMB1A–RMB8A, where *X* represents the most recently received valid value.

Supervise the transfer of received data (or default data) to RMB1A–RMB8A with the MIRRORED BITS pickup and dropout security counters. Set the pickup and dropout counters individually for each bit.

Appendix E

DNP3 Communications

Overview

The SEL-651R-2 Recloser Control provides a DNP3 (Distributed Network Protocol) Level 2 Outstation interface for direct network connections to the relay. This section covers the following topics:

➤ *Introduction to DNP3 on page E.1*

➤ *DNP3 in the SEL-651R-2 on page E.6*

➤ *DNP3 Documentation on page E.23*

Introduction to DNP3

A supervisory control and data acquisition (SCADA) manufacturer developed DNP3 from the lower layers of IEC 60870-5. DNP3 was designed for use in telecontrol applications. The protocol has become popular for both local substation data collection and telecontrol. DNP is one of the protocols included in the IEEE Recommended Practice for Data Communication between remote terminal units and intelligent electronic devices in a substation.

The DNP User's Group maintains and publishes DNP standards. See the DNP User's Group website, www.dnp.org, for more information on DNP standards, implementers of DNP, and tools for working with DNP.

DNP3 Specifications DNP3 is a feature-rich protocol with many ways to accomplish tasks, defined in an eight-volume series of specifications. Volume 8 of the specification, called the Interoperability Specification, simplifies DNP3 implementation by providing four standard interoperable implementation levels. The levels are listed in *Table E.1*.

Table E.1   DNP3 Implementation Levels

Level	Description	Equipment Types
1	Simple: limited communication requirements	Meters, simple IEDs
2	Moderately complex: monitoring and metering devices and multifunction devices that contain more data	Protective relays, RTUs
3	Sophisticated: devices with great amounts of data or complex communication requirements	Large RTUs, SCADA masters
4	Enhanced: additional data types and functionality for more complex requirements	Large RTUs, SCADA masters

E.2 | DNP3 Communications
Introduction to DNP3

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Each level is a proper superset of the previous lower-numbered level. A higher-level device can act as a master to a lower-level device, but can only use the data types and functions implemented in the lower level device. For example, a typical SCADA master is a Level 3 device and can use Level 2 (or lower) functions to poll a Level 2 (or lower) device for Level 2 (or lower) data. Similarly, a lower-level device can poll a higher-level device, but the lower level device can only access the features and data available to its level.

In addition to the eight-volume DNP3 specification, the protocol is further refined by conformance requirements, optional features, and a series of technical bulletins. The technical bulletins supplement the specifications with discussion and examples of specific features of DNP3.

Data Handling

Objects

DNP3 uses a system of data references called objects, which the Basic 4 standard object library defines. Each subset level specification requires a minimum implementation of object types and also recommends several optional object types. Object types are commonly referred to as objects. DNP3 objects are specifications for the type of data the object carries. An object can include a single value or more complex data. Some objects serve as shorthand references for special operations, including collections of data, time synchronization, or even all data within the DNP3 device.

If there can be more than one instance of a type of object, then each instance of the object includes an index that makes it unique. For example, each binary status point (Object 1) has an index. If there are 16 binary status points, these points are Object 1, Index 0–Object 1, Index 15.

Each object also includes multiple versions called variations. For example, Object 1 has three variations: 0, 1, and 2. Use Variation 0 to request the default variation. Variation 1 is used to specify binary input values only and Variation 2 is used to specify binary input values with status information.

Each DNP3 device has both a list of objects and a map of object indices. The list of objects defines the available objects, variations, and qualifier codes. The map defines the indices for objects that have multiple instances and defines what data or control points correspond with each index.

A master initiates all DNP3 message exchanges except unsolicited data. DNP3 terminology describes all points from the perspective of the master. Binary points for control that move from the master to the remote are called binary outputs, while binary status points within the remote are called binary inputs.

Function Codes

Each DNP3 message includes a function code. Each object has a limited set of function codes that a master may use to manipulate the object. The object listing for the device shows the permitted function codes for each type of object. The most common DNP3 function codes are listed in *Table E.2*.

Table E.2   Selected DNP3 Function Codes

Function Code	Function	Description
1	Read	Request data from the remote
2	Write	Send data to the remote
3	Select	First part of a select-before-operate operation
4	Operate	Second part of a select-before-operate operation
5	Direct operate	One-step operation with reply
6	Direct operate, no reply	One-step operation with no reply

Qualifier Codes and Ranges

DNP3 masters use qualifier codes and ranges to make requests for specific objects by index. Qualifier codes specify the style of range, and the range specifies the indices of the objects of interest. DNP3 masters use qualifier codes to compose the shortest, most concise message possible when requesting points from a DNP3 remote.

For example, the qualifier code 01 specifies that the request for points will include a start address and a stop address. Each of these two addresses uses two bytes. An example request using qualifier code 01 might have the four-hexadecimal byte range field, 00h 04h 00h 10h, that specifies points in the range 4 to 16.

Access Methods

DNP3 has many features that help it obtain maximum possible message efficiency. Requests are sent with the least number of bytes by using special objects, variations, and qualifiers that reduce the message size. Other features eliminate the continual exchange of data values that are not changing. These features optimize use of bandwidth and maximize performance over any speed connection.

DNP3 event data collection eliminates the need to use bandwidth to transmit values that have not changed. Event data are records of when observed measurements changed. For binary points, the remote device (DNP3 outstation) logs changes from logical 1 to logical 0 and from logical 0 to logical 1. For analog points, the remote device logs changes that exceed a dead band. DNP3 remote devices collect event data in a buffer that the master can either request or the relay can send to the master without a request message. Data sent from the remote to the master without a polling request are called unsolicited data.

DNP3 data fit into one of four event classes: 0, 1, 2, or 3. Class 0 is reserved for reading the present value data (static data). Classes 1, 2, and 3 are event data classes. The meaning of Classes 1 to 3 is arbitrary and defined by the application at hand. With remotes that contain great amounts of data or in large systems, the three event classes provide a framework for prioritizing different types of data. For example, you can poll once a minute for Class 1 data, once an hour for Class 2 data, and once a day for Class 3 data.

DNP3 also supports static polling, simple polling of the present value of data points within the remote. By combining event data, unsolicited polling, and static polling, you can operate your system in one of the four access methods shown in *Table E.3*.

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The access methods listed in *Table E.3* are in order of increasing communication efficiency. With various tradeoffs, each method is less demanding of communication bandwidth than the previous one. For example, unsolicited report-by-exception consumes less communication bandwidth because of the elimination of polling messages from the master required by polled report-by-exception. You must also consider overall system size and the volume of data communication expected to properly evaluate which access method provides optimum performance for your application.

Table E.3   DNP3 Access Methods

Access Method	Description
Polled static	Master polls for present value (Class 0) data only
Polled report-by-exception	Master polls frequently for event data and occasionally for Class 0 data
Unsolicited report-by-exception	Remote devices send unsolicited event data to the master, and the master occasionally polls for Class 0 data
Quiescent	Master never polls and relies on unsolicited reports only

Binary Control Operations

DNP3 masters use Object 12 (control relay output block) to perform DNP3 binary control operations. The control relay output block has both a trip/close selection and a code selection. The trip/close selection allows a single DNP3 index to operate two related control points such as trip and close or raise and lower.

The control relay output block code selection specifies either a latch or pulse operation on the point. In many cases, DNP3 remotes have only a limited subset of the possible combinations of the code field. Sometimes, DNP3 remotes assign special operation characteristics to the latch and pulse selections. *Table E.8* describes control point operation for the SEL-651R-2.

Conformance Testing

In addition to the protocol specifications, the DNP User's Group has approved conformance testing requirements for Level 1 and Level 2 devices. Some implementers perform their own conformance specification testing, while some contract with independent companies to perform conformance testing.

Conformance testing does not always guarantee that a master and remote will be fully interoperable (work together properly for all implemented features). Conformance testing does help to standardize the testing procedure and move the DNP implementers toward a higher level of interoperability. The SEL-651R-2 is tested for conformance using third-party conformance test software and has passed DNP Level 2 Slave Conformance tests. The conformance certificate is on file at SEL and listed on the DNP User's Group website (www.dnp.org).

DNP3 Serial Network Issues

Data Link Layer Operation

DNP3 employs a three-layer version of the seven-layer Open Systems Interconnect (OSI) model called the enhanced performance architecture. The layer definition helps to categorize functions and duties of various software components that make up the protocol. The middle layer, the data link layer, includes several functions for error checking and media access control.

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A feature called data link confirmation is a mechanism that provides positive confirmation of message receipt by the receiving DNP3 device. While this feature helps you recognize a failed device or failed communications link quickly, it also adds significant overhead to the DNP3 conversation. Consider for your individual application whether you require this link integrity function at the expense of overall system speed and performance.

The DNP technical bulletin (*DNP Confirmation and Retry Guidelines 9804-002*) on confirmation processes recommends against using data link confirmations because these processes can add to traffic in situations where communications are marginal. The increased traffic will reduce connection throughput further, possibly preventing the system from operating properly.

Network Medium Contention

When more than one device requires access to a single network medium, you must provide a mechanism to resolve the resulting network medium contention. For example, unsolicited reporting results in network medium contention if you do not design your network as a star topology of point-to-point connections or use carrier detection on a multidrop network.

To avoid collisions among devices trying to send messages, DNP3 includes a collision avoidance feature. Before sending a message, a DNP3 device listens for a carrier signal to verify that no other node is transmitting data. The device transmits if there is no carrier or waits for a random time before transmitting. However, if two nodes both detect a lack of carrier at the same instant, these two nodes could begin simultaneous transmission of data and cause a data collision. If your network allows for spontaneous data transmission including unsolicited event data transmissions, you also must use application confirmation to provide a retry mechanism for messages lost as a result of data collisions.

DNP3 LAN/WAN Overview

The main process for carrying DNP3 over an Ethernet Network (LAN/WAN) involves encapsulating the DNP3 data link layer data frames within the transport layer frames of the Internet Protocol (IP) suite. This allows the IP stack to deliver the DNP3 data link layer frames to the destination in place of the original DNP3 physical layer.

The DNP User Group Technical Committee has recommended the following guidelines for carrying DNP3 over a network:

NOTE: Link layer confirmations are explicitly disabled for DNP3 LAN/WAN. The IP suite already provides a reliable delivery mechanism, which is backed up at the application layer by confirmations when required.

> ➤ DNP3 shall use the IP suite to transport messages over a LAN/WAN

> ➤ Ethernet is the recommended physical link, though others may be used

> ➤ TCP must be used for WANs

> ➤ TCP is strongly recommended for LANs

> ➤ User Datagram Protocol (UDP) may be used for highly reliable single segment LANs

> ➤ UDP is necessary if broadcast messages are required

> ➤ The DNP3 protocol stack shall be retained in full

> ➤ Link layer confirmations shall be disabled

The Technical Committee has registered a standard port number, 20000, for DNP3 with the Internet Assigned Numbers Authority (IANA). This port is used for either TCP or UDP.

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TCP/UDP Selection

The Committee recommends the selection of TCP or UDP protocol as per the guidelines in *Table E.4*.

Table E.4   TCP/UDP Selection Guidelines

Use in the case of...	TCP	UDP
Most situations	X	
Nonbroadcast or multicast	X	
Mesh Topology WAN	X	
Broadcast		X
Multicast		X
High-reliability single-segment LAN		X
Pay-per-byte, nonmesh WAN, for example, Cellular Digital Packet Data (CDPD)		X
Low priority data, for example, data monitor or configuration information		X

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The SEL-651R-2 is a DNP3 Level 2 remote (outstation) device. Additional implementation documentation describing DNP3 in the relay is in *DNP3 Communications on page E.1*.

Data Access

NOTE: Because unsolicited messaging only operates properly in some situations, for maximum performance and minimum risk of configuration problems, use the polled report-by-exception access method. Configure the master to perform at least 10 event polls for every integrity poll.

NOTE: In the settings below, the suffix n represents the DNP3 LAN/WAN session number from 1 to 6. This suffix is not present in Serial Port DNP3 settings. All settings with the same numerical suffix comprise the complete DNP3 session configuration.

You can use any of the data access methods listed in *Table E.5*. *Table E.5* also lists the SEL-651R-2 DNP3 settings. You must configure the DNP3 master for the data access method you select.

Table E.5   DNP3 Access Methods

Access Method	Master Polling	SEL-651R-2 Settings
Polled static	Class 0	Set ECLASSB, ECLASSC, ECLASSA, ECLASSV to 0; UNSOL to No
Polled report-by-exception	Class 0 occasionally, Class 1, 2, 3 frequently	Set ECLASSB, ECLASSC, ECLASSA, ECLASSV to the desired event class; UNSOL to No
Unsolicited report-by-exception	Class 0 occasionally, optional Class 1, 2, 3 less frequently; mainly relies on unsolicited messages	Set ECLASSB, ECLASSC, ECLASSA, ECLASSV to the desired event class; set UNSOL to Yes and PUNSOL to Yes or No
Quiescent	Class 0, 1, 2, 3 never; relies completely on unsolicited messages	Set ECLASSB, ECLASSC, ECLASSA, ECLASSV to the desired event class; set UNSOL and PUNSOL to Yes.

In both the unsolicited report-by-exception and quiescent polling methods shown in *Table E.5*, you must make a selection for the PUNSOL setting. This setting enables or disables unsolicited data reporting at power up. If your master can send the DNP3 message to enable unsolicited reporting from the SEL-651R-2, you should set PUNSOL to No.

While automatic unsolicited data transmission on power up is convenient, problems can result if your master is not prepared to start receiving data immediately on power up. If the master does not acknowledge the unsolicited data with an Application Confirm, the relay will resend the data until it is acknowledged. On a large system, or in systems where the processing power of the master is limited, you may have problems when several relays simultaneously begin sending data and waiting for acknowledgment messages.

The SEL-651R-2 allows you to set the conditions for transmitting unsolicited event data on a class-by-class basis. It also allows you to assign points to event classes on a point-by-point basis (see *Configurable Data Mapping on page E.14*). You can prioritize data transmission with these event class features. For example, you might place high-priority points in event class 1 and set it with low thresholds (NUM1EVE and AGE1EVE settings) so that changes to these points will be sent to the master quickly. You might then place low priority data in event class 2 with higher thresholds.

If the SEL-651R-2 does not receive an Application Confirm in response to unsolicited data, it will wait for ETIMEO seconds and then repeat the unsolicited message. If any message, other than an Application Confirm with a matching sequence number, is received from the master during the ETIMEO interval, the SEL-651R-2 will continue to retry to send the unsolicited message at the ETIMEO interval. To prevent excess traffic on the network with unsolicited data retries, the SEL-651R-2 uses the URETRY and UTIMEO settings to increase retry time when the number of retries set in URETRY is exceeded. After URETRY has been exceeded, the SEL-651R-2 pauses UTIMEO seconds and then transmits the unsolicited data again. *Figure E.1* provides an example with URETRY := 2.
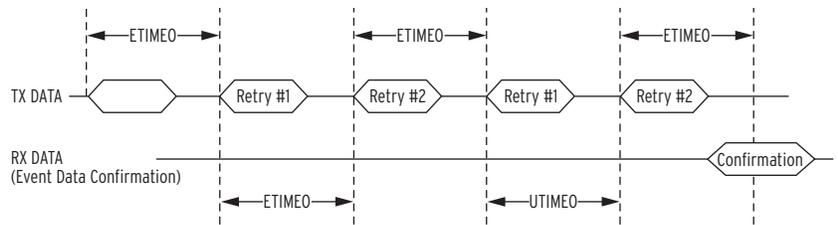
Figure E.1   Application Confirmation Timing With URETRY := 2

If using a modem and UTIMEO is set to OFF, the SEL-651R-2 hangs up the phone and re-dials instead of extending the delay to UTIMEO seconds. If the SEL-651R-2 does not receive an Application Confirm in response to unsolicited data, it will wait for ETIMEO seconds and then repeat the unsolicited message. When the number of retries exceeds URETRY, the SEL-651R-2 will hang up the phone and wait 10 • ETIMEO seconds, then it will redial a phone number. When PH_NUM1 and PH_NUM2 are both populated, the SEL-651R-2 will alternate between the two phone numbers each time it redials, otherwise it will redial PH_NUM1.

Collision Avoidance

If your application uses unsolicited reporting, you must select a half-duplex medium or a medium that includes carrier detection to avoid data collisions. EIA-485 two-wire networks are half-duplex. EIA-485 four-wire networks do not provide carrier detection, while EIA-232 systems can support carrier detection.

NOTE: MINDLY and MAXDLY settings are only available for EIA-232 and EIA-485 serial port sessions.

The relay uses Application Confirmation messages to guarantee delivery of unsolicited event data before erasing the local event data buffer. Data collisions are typically resolved when messages are repeated until confirmed.

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The SEL-651R-2 pauses for a random delay between the settings MAXDLY and MINDLY when it detects a carrier through data on the receive line or the CTS pin. If you use the settings of 0.10 seconds for MAXDLY and 0.05 seconds for MINDLY, the SEL-651R-2 will insert a random delay of 50 to 100 ms between the end of carrier detection and the start of data transmission (see *Figure E.2*).
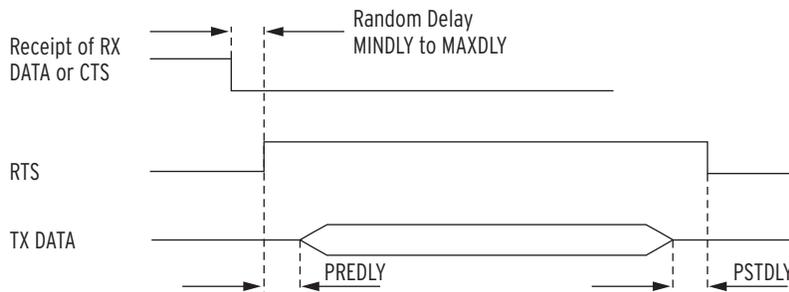
Figure E.2   Message Transmission Timing

Transmission Control

If you use a media transceiver (for example, EIA-232 to EIA-485) or a radio system for your DNP3 network, you may need to adjust data transmission properties. Use the PREDLY and POSTDLY settings to provide a delay between RTS signal control and data transmission (see *Figure E.2*). For example, an EIA-485 transceiver typically requires 10 to 20 ms to change from receive to transmit. If you set the predelay to 30 ms, you will avoid data loss resulting from data transmission beginning at the same time as RTS signal assertion.

In applications where the radio system has a limited packet size capability, the RESPSZ can be set to send smaller DNP3 messages. The default RESPSZ specifies the maximum response size as 2411 octets. The message size of 2411 contains a Maximum Application Layer Fragment of 2048 octets plus the DNP3 Application Layer, Transport Function and Data Link Layer overhead. RESPSZ can be set from 200 to 2411 octets if the communications network limits the message size.

Binary Controls

The SEL-651R-2 provides more than one way to control individual points within the relay. The relay maps incoming control points either to remote bits within the relay or to internal command bits that cause circuit breaker operations. *Table E.8* lists control points and control methods available in the SEL-651R-2.

A DNP technical bulletin *(Control Relay Output Block Minimum Implementation 9701-002)* recommends that you use one point per Object 12 (control relay output block). You can use this method to perform Pulse On, Pulse Off, Latch On, and Latch Off operations on selected remote bits.

If your master does not support the single-point-per-index messages or single-operation database points, you can use the trip/close operation or use the code field in the DNP3 message to specify operation of the points as shown in *Control Point Operation on page E.22*.

Time Synchronization

The accuracy of DNP3 time synchronization is insufficient for most protection and oscillography needs. DNP3 time synchronization provides backup time synchronization in the event the relay loses primary synchronization through the IRIG-B input. Enable time synchronization with the TIMERQ setting and use Object 50, Variation 1 to set the time via the Session *n* DNP3 master

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(Object 50, Variation 3 for DNP3 LAN/WAN). Object 51, Variation 2 (Unsynchronized Time and Date CTO) is supported but only in conjunction with Object 2, Variation 3 (Binary Input Change With Relative Time).

By default, the SEL-651R-2 accepts and ignores time set requests (TIMERQ := I). (This mode allows the SEL-651R-2 to use a high-accuracy IRIG-B time source, but still interoperate with DNP3 masters that send time synchronization messages.) It can be set to request time synchronization periodically by setting the TIMERQ setting to the desired period. It can also be set to accept, but not request, time synchronization (TIMERQ = M).

If synchronization of relay time occurs only over DNP3, the relay time is synchronized for a period based on the TIMERQ Port setting. When the TIMERQ setting is less than 30 minutes, the relay is time-synchronized for twice the TIMERQ setting. When the TIMERQ setting is greater than 30 minutes, the relay is time synchronized for 30 minutes plus the TIMERQ setting. When TIMERQ is not set to a time (TIMERQ := M) for any port, the time is synchronized for 60 minutes. When the device is time-synchronized, an Object 2, Variation 3 (Binary Input Event with Relative Time) request will result in Object 51, Variation 1 (Time and Date Common Time-of-Occurrence—synchronized) response. When the device is no longer time-synchronized, an Object 2, Variation 3 (Binary Input Event with Relative Timer) request will result in Object 51, Variation 2 (Time and Date Common Time-of-Occurrence—unsynchronized) response.

Modem Support

The SEL-651R-2 DNP3 implementation includes modem support. Your DNP3 master can dial in to the SEL-651R-2 and establish a DNP3 connection. The SEL-651R-2 can automatically dial out and deliver unsolicited DNP3 event data. When the relay dials out, it waits for the "CONNECT" message from the local modem and for assertion of the relay CTS line before continuing the DNP3 transaction. This requires a connection from the modem DCD to the relay CTS line.

NOTE: Contact SEL for information on serial cable configurations and requirements for connecting your SEL-651R-2 to other devices.

NOTE: RTS/CTS hardware flow control is not available for a DNP3 modem connection. You must use either X-ON/X-OFF software flow control or set the port data speed slower than the effective data rate of the modem.

Either connect the modem to a computer and configure it before connecting it to the relay, or program the appropriate modem setup string in the modem startup string setting MSTR. Use the PH_NUM1 setting to set the phone number that you want the relay to call. The relay automatically will send the ATDT modem dial command and then the contents of the PH_NUM1 setting when dialing the modem. PH_NUM1 is a text setting that must conform to the AT modem command set dialing string standard. Use a comma (,) for a pause of four seconds. You may need to include a nine to reach an outside line or a one if the number requires long distance access. You can also insert other special codes your telephone service provider designates for block call waiting and other telephone line features.

The SEL-651R-2 supports the use of two phone numbers for its modem support. This can be extremely useful where a communications link is unreliable, or is likely to become very congested (i.e., many devices reporting to the same phone number). If the second phone number is enabled, the SEL-651R-2 will attempt to make a connection on the primary phone number (PH_NUM1). If the connection attempt is unsuccessful, the SEL-651R-2 will retry for a set number of times (RETRY1). If no connection is accomplished within the set number of retries, the control will then attempt to connect via the second phone number (PH_NUM2). Connection via the second phone number (PH_NUM2) will be attempted for a set number of retries (RETRY2). If, after the set number of retries, no connection has been made, the SEL-651R-2 will revert to the first phone number (PH_NUM1) and the process will repeat. When PH_NUM2 is set to OFF, the SEL-651R-2 will continue connection attempts using the first phone number (PH_NUM1).

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DNP3 Settings

The DNP3 port configuration settings available on the SEL-651R-2 are shown in *Table E.6*. You can enable DNP3 on any of the Serial Ports 1, 2, 3, or F or on Ethernet Port 5, to a maximum of six concurrent DNP3 sessions.

The SEL-651R-2 allows as many as six simultaneous DNP3 sessions. All six DNP3 sessions can be on the Ethernet port or on a combination of the four separate serial ports and Ethernet sessions (see *Table 10.7* for DNP3 protocol session limitations).

Each session defines the connected DNP3 Master characteristics you assign to one of the three available custom maps. Some settings only apply to DNP3 LAN/WAN and are visible only when configuring the Ethernet port. For example, you only have the ability to define multiple sessions (as many as six) on the Ethernet Port 5. For this reason, DNP3 settings for Ethernet sessions have a suffix, n, that indicates the session number from one to six (e.g., DNPIP1, ETIMEO2, and AGE1EVE3). Serial DNP3 ports do not support multiple sessions, so they do not have the suffix, *n*.

Table E.6   SEL-651R-2 Port DNP3 Protocol Settings (Sheet 1 of 4)

Head/Name	Description	Range	Default Value
Serial Port 1–4 Settings			
DNPADR	Device DNP3 Address	0–65519	0
REPADR	DNP3 address of the Master to send messages to	0–65519	1
DNPMAP	DNP3 Session Custom Map	1–3	1
DVARAI	Analog Input Default Variation	1–6	4
ECLASSB	Class for binary event data, 0 disables	0–3	1
ECLASSC	Class for counter event data, 0 disables	0–3	0
ECLASSA	Class for analog event data, 0 disables	0–3	2
ECLASSV	Class for virtual terminal response data	0–3	3
DECPLA	Decimal places scaling for current data	0–3	1
DECPLV	Decimal places scaling for voltage data	0–3	1
DECPLM	Decimal places scaling for miscellaneous data	0–3	1
ANADBA	Analog reporting dead band for current; hidden if ECLASSA set to 0	0–32767	100
ANADBV	Analog reporting dead band for voltages; hidden if ECLASSA set to 0	0–32767	100
ANADBM	Analog reporting dead band for miscellaneous analogs; hidden if ECLASSA and ECLASSC set to 0	0–32767	100
TIMERQ	Time set request interval, minutes (M = Disables time synchronize requests, but still accepts and applies time synchronizes from Master; I = Ignores [does not apply] time synchronizes from Master)	I, M, 1–32767	I
STIMEO	Select/operate time out, seconds	0.0–30.0	1
DRETRY	Data link retries	0–15	0
DTIMEO	Data link time out, seconds; hidden if DRETRY set to 0	0–5	1
RESPSZ	Maximum Response Size	200–2411 bytes	2411
ETIMEO	Event message confirm time out, seconds	1–120	5
UNSOL	Enable unsolicited reporting; hidden and set to N if ECLASSB, ECLASSC, and ECLASSA set to 0	Y, N	N
PUNSOL[a]	Enable unsolicited reporting at power up; hidden and set to N if UNSOL set to N	Y, N	N
NUM1EVE[a]	Threshold to send unsolicited message on Class 1 data	1–200	10
AGE1EVE[a]	Time threshold to send unsolicited message on for Class 1 data	0.0–99999.0	2

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Table E.6   SEL-651R-2 Port DNP3 Protocol Settings (Sheet 2 of 4)

Head/Name	Description	Range	Default Value
NUM2EVE[a]	Threshold to send unsolicited message on Class 2 data	1–200	10
AGE2EVE[a]	Time threshold to send unsolicited message on for Class 2 data	0.0–99999.0	2
NUM3EVE[a]	Threshold to send unsolicited message on Class 3 data	1–200	10
AGE3EVE[a]	Time threshold to send unsolicited message on for Class 3 data	0.0–99999.0	2
URETRY[a]	Unsolicited messages maximum retry attempts	2–10	3
UTIMEO[a]	Unsolicited messages offline timeout, seconds	OFF, 2–5000	60
MINDLY	Minimum delay from DCD to TX, seconds	0.00–1.00	0.05
MAXDLY	Maximum delay from DCD to TX, seconds	0.00–1.00	0.1
PREDLY	Settle time from RTS on to TX, seconds; OFF disables PSTDLY	OFF, 0.00–30.00	0
PSTDLY	Settle time from TX to RTS off, seconds; hidden if PREDLY set to OFF	0.00–30.00	0
EVEMODE	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP	Selects event report types to be reported in the DNP3 event summary data	TRIP, ALL	ALL
DNP3 Modem Settings			
MODEM	Modem connected to port	Y, N	N
MSTR	Modem startup string; hidden if MODEM set to N	As many as 30 characters	"E0X0&D0S0=4"
PH_NUM1	Phone number 1 for unsolicited reporting dialout; hidden if MODEM set to N or UNSOL set to N	As many as 30 characters	""
PH_NUM2	Phone number 2 for unsolicited reporting dialout; hidden if MODEM set to N or UNSOL set to N	As many as 30 characters	""
RETRY1	Retry attempts for Phone Number 1 dialout	1–20	5
RETRY2	Retry attempts for Phone Number 2 dialout	1–20	5
MDTIME	Time to attempt dial, seconds	5–300	60
MDRET	Time between dial-out attempts, seconds	5–3600	120
Ethernet DNP3 Settings			
EDNP	Enable DNP3 Sessions	0–6	0
DNPNUM	DNP3 TCP and UDP Port	1–65534	20000
DNPADR	Device DNP3 Address	0–65519	0
Session 1 Settings			
DNPIP1[b,c]	IP address (zzz.yyy.xxx.www)	15 characters	""
DNPTR1	Transport protocol	UDP, TCP	TCP
DNPUDP1	UDP Response port; hidden if DNPTR1 set to TCP	REQ, 1–65534	20000
REPADR1	DNP3 address of the Master to send messages to	0–65519	0
DNPMAP1	DNP3 session custom map	1–3	1
DVARAI1	Analog input default variation	1–6	4
ECLASSB1	Class for binary event data, 0 disables	0–3	1
ECLASSC1	Class for counter event data, 0 disables	0–3	0
ECLASSA1	Class for analog event data, 0 disables	0–3	2
DECPLA1	Decimal places scaling for current data	0–3	1
DECPLV1	Decimal places scaling for voltage data	0–3	1
DECPLM1	Decimal places scaling for miscellaneous data	0–3	1

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Table E.6 SEL-651R-2 Port DNP3 Protocol Settings (Sheet 3 of 4)

Head/Name	Description	Range	Default Value
ANADBA1	Analog reporting dead band for current; hidden if ECLASSA1 set to 0	0–32767	100
ANADBV1	Analog reporting dead band for voltages; hidden if ECLASSA1 set to 0	0–32767	100
ANADBM1	Analog reporting dead band for miscellaneous analogs; hidden if ECLASSA1 and ECLASSC1 set to 0	0–32767	100
TIMERQ1	Timeset request interval, minutes (M = Disables time synchronize requests, but still accepts and applies time synchronization from Master; I = Ignores (does not apply) time synchronization from Master)	I, M, 1–32767	I
STIMEO1	Select/operate timeout, seconds	0.0–30.0	1
DNPINA1	Send data link heartbeat, seconds; hidden if DNPTR1 set to UDP	0–7200	120
ETIMEO1	Event message confirm timeout, seconds	1–120	5
UNSOL1	Enable unsolicited reporting; hidden and set to N if ECLASSB1, ECLASSC1, and ECLASSA1 set to 0	Y, N	N
PUNSOL1[a]	Enable unsolicited reporting at power up; hidden and set to N if UNSOL1 set to N	Y, N	N
NUM1EVE1[a]	Threshold to send unsolicited message on Class 1 data	1–200	10
AGE1EVE1[a]	Time threshold to send unsolicited message on for Class 1 data	0.0–99999	2
NUM2EVE1[a]	Threshold to send unsolicited message on Class 2 data	1–200	10
AGE2EVE1[a]	Time threshold to send unsolicited message on for Class 2 data	0.0–99999	2
NUM3EVE1[a]	Threshold to send unsolicited message on Class 3 data	1–200	10
AGE3EVE1[a]	Time threshold to send unsolicited message on for Class 3 data	0.0–99999	2
URETRY1[a]	Unsolicited messages maximum retry attempts	2–10	3
UTIMEO1[a]	Unsolicited messages offline timeout, seconds	2–5000	60
EVEMODE1	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP1	Selects event report types to be reported in the DNP3 event summary data	TRIP, ALL	ALL
Session 2 Settings			
DNPIP2[b,c]	IP address (zzz.yyy.xxx.www)	15 characters	""
DNPTR2	Transport protocol	UDP, TCP	TCP
•			
•			
•			
EVEMODE2	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP2	Selects event report types to be reported in the DNP3 event summary	TRIP, ALL	ALL
Session 3 Settings			
DNPIP3[b,c]	IP address (zzz.yyy.xxx.www)	15 characters	""
DNPTR3	Transport protocol	UDP, TCP	TCP
•			
•			
•			
EVEMODE3	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP3	Selects event report types to be reported in the DNP3 event summary	TRIP, ALL	ALL

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Table E.6   SEL-651R-2 Port DNP3 Protocol Settings (Sheet 4 of 4)

Head/Name	Description	Range	Default Value
Session 4 Settings			
DNPIP4[b,c]	IP address (zzz.yyy.xxx.www)	15 characters	""
DNPTR4	Transport protocol	UDP, TCP	TCP
•			
•			
•			
EVEMODE4	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP4	Selects event report types to be reported in the DNP3 event summary	TRIP, ALL	ALL
Session 5 Settings			
DNPIP5[b,c]	IP address (zzz.yyy.xxx.www)	15 characters	""
DNPTR5	Transport protocol	UDP, TCP	TCP
•			
•			
•			
EVEMODE5	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP5	Selects event report types to be reported in the DNP3 event summary	TRIP, ALL	ALL
Session 6 Settings			
DNPIP6[b,c]	IP address (zzz.yyy.xxx.www)	15 characters	""
DNPTR6	Transport protocol	UDP, TCP	TCP
•			
•			
•			
EVEMODE6	Selects event mode in which each DNP3 session will start up	SINGLE, MULTI	SINGLE
RPEVTYP6	Selects event report types to be reported in the DNP3 event summary	TRIP, ALL	ALL

[a] Hidden if UNSOLn set to N.
[b] DNP IP Address of each session (DNPIP1, DNPIP2, etc.) must be unique.
[c] Set DNPIPn = 0.0.0.0 to accept connections from any DNP master (on up to one DNP session, DNPTRn = TCP only). This will not allow connections with masters that have IP addresses that are included in the DNPIPn setting for another session.

The SEL-651R-2 allows one DNP3 session to be configured to accept an anonymous DNP3 master connection through use of the Port 5 setting DNPIPn = 0.0.0.0. For this session, the SEL-651R-2 will accept a DNP3 connection request from any DNP3 master whose address is not configured as DNPIPn in another session.

Be advised that once an anonymously connected DNP3 master disconnects from the session in which DNPIPn = 0.0.0.0, that session is again available, and any DNP3 master that requests a connection (whose address is not explicitly set as a DNPIPn setting elsewhere) will connect to the anonymous session.

DNP3 events and class polls are associated with the session, not with a particular DNP3 master. If a DNP3 master disconnects from the anonymous session and a different DNP3 master then connects, previously acknowledged DNP3 events will not be re-sent by the SEL-651R-2.

Because the SEL-651R-2 will accept *any* connection when a session is configured with DNPIPn = 0.0.0.0, ensure that you use secure network practices to avoid unintended or undesired access.

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Configurable Data Mapping

One of the most powerful features of the SEL-651R-2 implementation is the ability to remap DNP3 data and, for analog values, specify per-point scaling, dead bands, and event class. Remapping is the process of selecting data from the reference map and organizing it into a data subset optimized for your application. The SEL-651R-2 uses object and point labels, rather than point indices, to streamline the remapping process. This enables you to quickly create a custom map without having to search for each point index in a large reference map.

You can use any of the three available DNP3 maps simultaneously with as many as six unique DNP3 masters. Each map is initially populated with default data points, as described in *Reference Data Map on page E.30*. You can remap the points in a default map to create a custom map with as many as:

> ➤ 200 Binary Inputs

> ➤ 71 Binary Outputs

> ➤ 200 Analog Inputs

> ➤ 8 Analog Outputs

> ➤ 16 Counters

You can use the **SHOW D** *x* **<Enter>** command to view the DNP3 data map settings, where *x* is the DNP3 map number from 1 to 3. See *Figure E.3* for an example display of Map 1.

```
=>>SHO D 1 <Enter>

DNP Map Settings 1
BI_000  :=TRIPLED   BI_001  :=EN        BI_002  :=TLED_01
BI_003  :=TLED_02   BI_004  :=TLED_03   BI_005  :=TLED_04
BI_006  :=TLED_05   BI_007  :=TLED_06   BI_008  :=TLED_07
BI_009  :=TLED_08   BI_010  :=TLED_09   BI_011  :=TLED_10
.
.
.
BI_195  :=NA        BI_196  :=NA        BI_197  :=NA
BI_198  :=NA        BI_199  :=NA

BO_000  :=RB01             BO_001  :=RB02
BO_002  :=RB03             BO_003  :=RB04
.
.
.
BO_068 :=NA               BO_069 :=NA
BO_070 :=NA

AI_000  :=IA              AI_001  :=IB
AI_002  :=IC              AI_003  :=IN
AI_004  :=IG              AI_005  :=VAY
AI_006  :=VBY             AI_007  :=VCY
AI_008  :=VAZ             AI_009  :=VBZ
AI_010  :=VCZ             AI_011  :=MW3
.
.
.
AI_198  :=NA              AI_199  :=NA

AO_000  :=ACTGRP AO_001  :=NA      AO_002  :=NA     AO_003  :=NA
AO_004  :=NA     AO_005  :=NA      AO_006  :=NA     AO_007  :=NA

CO_000  :=ACTGRP          CO_001  :=INTTA
CO_002  :=INTTB           CO_003  :=INTTC
CO_004  :=EXTTA           CO_005  :=EXTTB
CO_006  :=EXTTC           CO_007  :=NA
.
.
.
CO_014  :=NA              CO_015  :=NA
=>>
```

Figure E.3   Sample Response to SHO D Command

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You can use the command **SET D** *x*, where *x* is the map number, to edit or create custom DNP3 data maps. You can also use the ACSELERATOR QuickSet SEL-5030 Software, which is recommended for this purpose.

The following are valid entries if you choose to use the **SET D** command to create or edit custom maps:

> ➤ Binary Inputs—Any Relay Word bit label or additional DNP3 binary input (see *Binary Inputs on page E.20*) with class, e.g., RB01:2, the values 0 or 1, or NA

> ➤ Binary Outputs—Any Remote bit label or pair, Breaker bit label or pair, or additional DNP3 binary output (see *Binary Outputs on page E.20*), or NA

> ➤ Analog Inputs—Any analog input quantity (see *Analog Inputs on page E.22*) with scaling and/or dead band value, and/or class, e.g., IA:0, 1:50:2 (see below), the values 0 or 1, or NA

> ➤ Analog Outputs—Any analog output label (see *Table E.11*), NOOP, or NA

> ➤ Counter Inputs—Any counter label with dead band and/or class, e.g., ACTGRP:0:3 (see *Table E.11*)

For the above custom map settings, a label of 0 or 1 shall yield the label value when the point is polled. A NOOP can be used as a placeholder for analog outputs—control of a point with this label does not change any relay values nor respond with an error message. Any gaps left in the custom map between labels (NA) will be removed and the contents packed.

You can customize the DNP3 analog input map with per-point scaling, dead band, and event class settings. Scaling (DECPLA, DECPLV, and DECPLM), dead band (ANADBA, ANADBV, and ANADBM), and event class (ECLASSA) settings are applied to indices that do not have per-point entries. Per-point dead band settings override any class dead band settings. Per-point scaling overrides any class scaling and multiplies the analog input by the scaling value. Unlike per-point scaling, class-level scaling is specified by an integer in the range 0–3 (inclusive), which indicates the number of decimal place shifts. In other words, you should select 0 to multiply by 1, 1 for 10, 2 for 100, or 3 for 1000.

Per-point scaling factors allow you to overcome the limitations imposed, by default, of the integer nature of Objects 30 and 32. For example, DNP3 in the SEL-651R-2, by default, truncates a value of 11.4 A to 11 A. You may use per-point scaling to include decimal point values by multiplying by a power of 10. For example, if you use 10 as a scaling factor, 11.4 A will be transmitted as 114. You must divide the value by 10 in the master to see the original value including one decimal place.

You can also use per-point scaling to avoid overflowing the 16-bit maximum integer value of 32767. For example, if you have a value that can reach 157834, you cannot send it using DNP3 16-bit analog object variations. You could use a scaling factor of 0.1 so that the maximum value reported is 15783. You can then multiply the value by 10 in the master to see a value of 157830. You will lose some precision as the last digit is truncated off in the scaling process, but you can transmit the scaled value using the default variations for DNP3 Objects 30 and 32.

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Assign Class (Function Code 22) allows assigning and re-assigning of data objects to class 0, 1, 2, and 3 dynamically during run-time, with an Object 60 (FC 22) request. Per-point class assignments override the ECLASSB, ECLASSC, and ECLASSA settings for the binary inputs, counters, and analog inputs, respectively.

If your DNP3 master has the capability to request floating-point analog input variations, the SEL-651R-2 will support them. These floating point variations, 5 and 6 for Object 30 and 5–8 for Object 32, allow the transmission of 16- or 32-bit floating-point values to DNP3 masters. When implemented, these variations eliminate the need for scaling and still maintain the resolution of the relay analog values. Note that this support is greater than DNP3 Level 4 functionality, so you must confirm that your DNP3 master can work with these variations before you consider using unscaled analog values.

If it is important to maintain tight data coherency (that is, all data reads of a certain type were sampled or calculated at the same time), then you should group those data together within your custom map. For example, if you want all the currents to be coherent, you should group points IA, IB, IC, and IN together in the custom map. If points are not grouped together, they might not come from the same data sample.

The following example describes how to create a custom DNP3 map by point type. The example demonstrates the SEL ASCII command **SET D** for each point type, but the entire configuration may be completed without saving changes between point types. To do this, you simply continue entering data and save the entire map at the end. Alternatively, you can use QuickSet to simplify custom data map creation.

Consider a case where you want to set the AI points in a map as shown in *Table E.7*.

Table E.7   Sample Custom DNP3 AI Map

Desired Point Index	Description	Label	Scaling	Dead Band	Class
0	IA magnitude	IA	default	default	1
1	IB magnitude	IB	default	default	1
2	IC magnitude	IC	default	default	1
3	IN magnitude	IN	default	default	1
4	Three-Phase Real Power	MW3	5	default	default
5	Y-Terminal A-Phase-to-Neutral Voltage Magnitude	VAY	default	default	default
6	Y-Terminal A-Phase-to-Neutral Voltage Angle	VAYFA	1	15	default
7	Frequency	FREQ	0.01	1	default

To set these points as part of Custom Map 1, you can use the command **SET D 1 AI_000 TERSE <Enter>** as shown in *Figure E.4*.

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```
=>>SET D 1 AI_OOO TERSE <Enter>

DNP Map Settings 1

Analog Input Map
  (DNP Analog Input Label:Scale Factor:Deadband:Class):
DNP Analog Input Label Name
AI_OOO  := NA
      ? IA:::1

DNP Analog Input Label Name
AI_OO1  := NA
      ? IB:::1

DNP Analog Input Label Name
AI_OO2  := NA
      ? IC:::1

DNP Analog Input Label Name
AI_OO3  := NA
      ? IN:::1

DNP Analog Input Label Name
AI_OO4  := NA
      ? MW3:5

DNP Analog Input Label Name
AI_OO5  := NA
      ? VAY

DNP Analog Input Label Name
AI_OO6  := NA
      ? VAYFA:1:15

DNP Analog Input Label Name
AI_OO7  := NA
      ? FREQ:0.01:1

DNP Analog Input Label Name
AI_OO8  := NA
      ? END

Save Changes(Y/N)? Y

Settings saved
=>>
```

Figure E.4   Sample Custom DNP3 AI Map Settings

You can also use QuickSet to enter the above AI map settings as shown in *Figure E.5*. To enter scaling, dead band, or class setting, double-click the AI point and enter the values in the pop-up dialog, as shown in *Figure E.6*.

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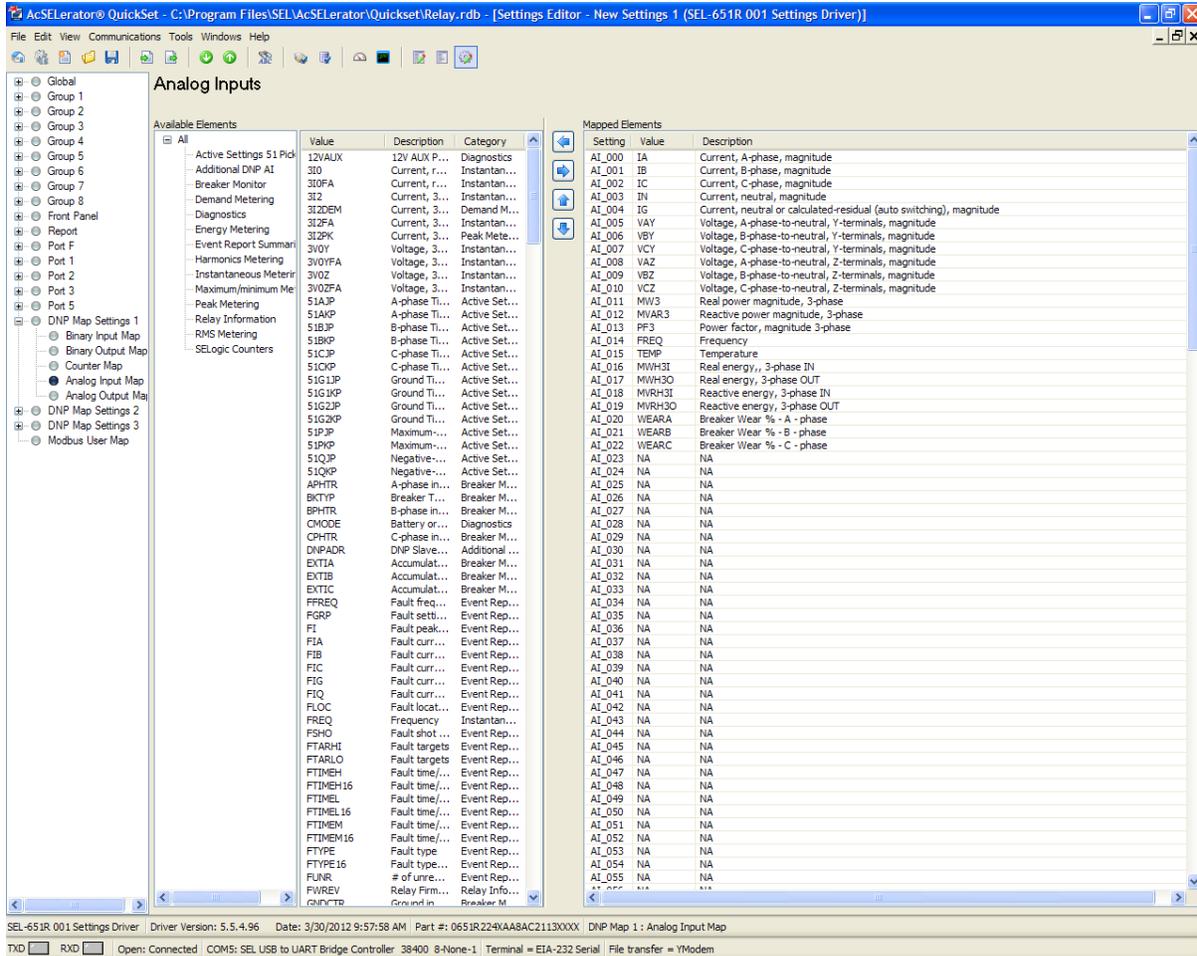
Figure E.5   Analog Input Map Entry in QuickSet
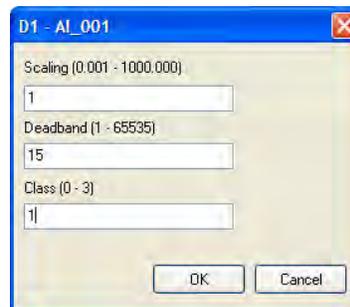
Figure E.6   AI Point Label, Scaling, Dead Band, and Class in QuickSet

The **SET D x CO_000 TERSE <Enter>** command allows you to populate the DNP3 counter map with per-point dead bands and class. Entering these settings is similar to defining the analog input map settings.

You can use the command **SET D *x* BO_000 TERSE <Enter>** to change the binary output Map *x* as shown in *Figure E.7*. You may populate the custom BO map with any of the 32 remote bits (RB01–RB32), breaker bits (OC3, CC3, OCA, CCA, OCB, CCB, OCC, CCC), reset bits (DRST_DEM, DRST_PDM, DRST_BK, DRST_HIS, DRST_ENE, DRST_MML, DRST_TAR, DRST_HAL, DRSTDNPE), NXTEVE, or SINGEVE bit. You can define bit pairs for remote bits or breaker bits in BO maps by including a colon (:) between the bit labels.

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```
=>>SET D 1 BO_OOO TERSE <Enter>


DNP Map Settings 1


Binary Output Map:
DNP Binary Output Label Name
BO_OOO  := NA
      ? RB01


DNP Binary Output Label Name
BO_001  := NA
      ? RB02


DNP Binary Output Label Name
BO_002  := NA
      ? RB03:RB04


DNP Binary Output Label Name
BO_003  := NA
      ? RB05:RB06


DNP Binary Output Label Name
BO_004  := NA
      ? END


Save Changes(Y/N)? Y <Enter>


Settings saved
=>>
```

Figure E.7   Sample Custom DNP3 BO Map Settings

You can also use QuickSet to enter the BO map settings as shown in *Figure E.8*.
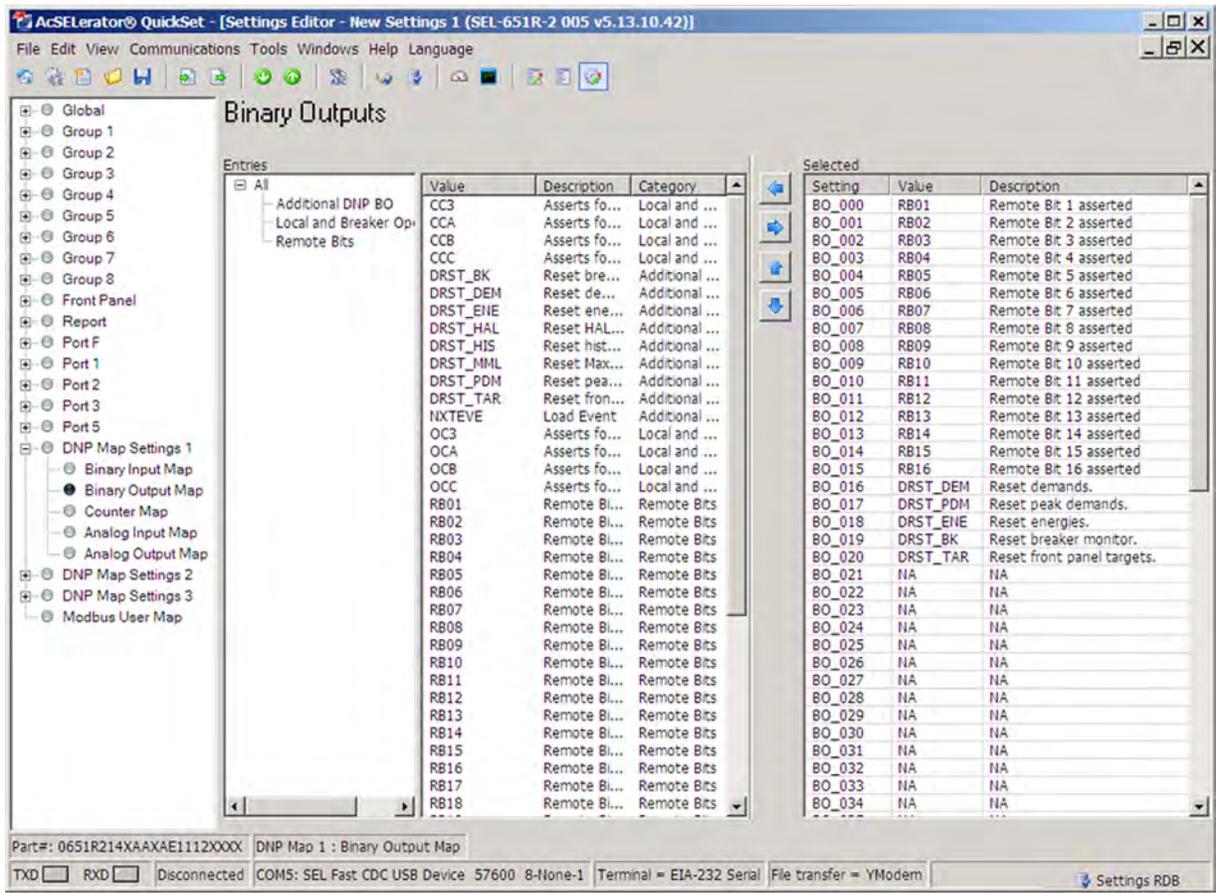
Figure E.8   Binary Output Map Entry in QuickSet

The binary input (BI) maps are modified in a similar manner, but pairs are not allowed.

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Binary Inputs

Binary Inputs (Objects 1 and 2) are supported as defined in *Table E.10*. The default variation for both static and event inputs is 2. Only the Read function code (1) is allowed with these objects. All variations are supported. Function Code 22 (Class Assign) is allowed on Object 1, variation 0 in conjunction with an Object 60 Assign Class function. Object 2, variation 3 will be responded to, but will contain no data.

Binary inputs are scanned approximately once per second to generate events. When time is reported with these event objects, it is the time at which the scanner observed the bit change. This may be significantly delayed from when the original source changed and should not be used for sequence-of-events determination. Binary inputs registered with SER are derived from the SER and carry the time stamp of actual occurrence.

Binary Outputs

Binary Outputs are supported as defined in *Table E.10* and *Table E.11*. Binary Output status (Object 10, variation 2) is supported. Static reads of points RB1–RB32 respond with the online bit set and the state of the requested bit. Reads of NXTEVE respond with the online bit set and a state of 1 if event summary data are being read in multiple-event FIFO mode and a state of 0 otherwise. Reads of SINGEVE respond with the online bit set and a state of 1 when event summary data are being read in single-event mode and a state of 0 when event summary data are being read in multiple-event mode. Reads from breaker control points (OC3, CC3, OCA, etc.) and control-only binary output points (such as the data reset controls DRST_DEM, DRST_ENE, etc.) respond with the online bit set and a state of 0 (or tripped) because of the pulse only control operation of these points.

Control Relay Output Block (CROB) objects (Object 12, variation 1) are also supported. The control relays correspond to the remote bits and other functions as shown below. The Trip/Close bits take precedence over the control field. The control field is interpreted as follows.

Table E.8 Object 12 Control Relay Operations (Sheet 1 of 2)

Label	Index	Close	Trip	Latch On (3)	Latch Off (4)	Pulse On (1)	Pulse Off (2)
RB*x*	0–15	Set RB01–RB16	Clear RB01–RB16	Set RB01–RB16	Clear RB01–RB16	Pulse RB01–RB16	Clear RB01–RB16
OC3	16	Pulse OC3	No action	Pulse OC3	No action	Pulse OC3	No action
CC3	17	Pulse CC3	No action	Pulse CC3	No action	Pulse CC3	No action
OCA	18	Pulse OCA	No action	Pulse OCA	No action	Pulse OCA	No action
CCA	19	Pulse CCA	No action	Pulse CCA	No action	Pulse CCA	No action
OCB	20	Pulse OCB	No action	Pulse OCB	No action	Pulse OCB	No action
CCB	21	Pulse CCB	No action	Pulse CCB	No action	Pulse CCB	No action
OCC	22	Pulse OCC	No action	Pulse OCC	No action	Pulse OCC	No action
CCC	23	Pulse CCC	No action	Pulse CCC	No action	Pulse CCC	No action
RB01:RB02	24	Pulse RB02	Pulse RB01	Pulse RB02	Pulse RB01	Pulse RB02	Pulse RB01
RB03:RB04	25	Pulse RB04	Pulse RB03	Pulse RB04	Pulse RB03	Pulse RB04	Pulse RB03
RB05:RB06	26	Pulse RB06	Pulse RB05	Pulse RB06	Pulse RB05	Pulse RB06	Pulse RB05
RB07:RB08	27	Pulse RB08	Pulse RB07	Pulse RB08	Pulse RB07	Pulse RB08	Pulse RB07
RB09:RB10	28	Pulse RB10	Pulse RB09	Pulse RB10	Pulse RB09	Pulse RB10	Pulse RB09

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Table E.8 Object 12 Control Relay Operations (Sheet 2 of 2)

Label	Index	Close	Trip	Latch On (3)	Latch Off (4)	Pulse On (1)	Pulse Off (2)
RB11:RB12	29	Pulse RB12	Pulse RB11	Pulse RB12	Pulse RB11	Pulse RB12	Pulse RB11
RB13:RB14	30	Pulse RB14	Pulse RB13	Pulse RB14	Pulse RB13	Pulse RB14	Pulse RB13
RB15:RB16	31	Pulse RB16	Pulse RB15	Pulse RB16	Pulse RB15	Pulse RB16	Pulse RB15
OC3:CC3	32	Pulse CC3	Pulse OC3	Pulse CC3	Pulse OC3	Pulse CC3	Pulse OC3
OCA:CCA	33	Pulse CCA	Pulse OCA	Pulse CCA	Pulse OCA	Pulse CCA	Pulse OCA
OCB:CCB	34	Pulse CCB	Pulse OCB	Pulse CCB	Pulse OCB	Pulse CCB	Pulse OCB
OCC:CCC	35	Pulse CCC	Pulse OCC	Pulse CCC	Pulse OCC	Pulse CCC	Pulse OCC
DRST_DEM	36	Reset demands	No action	Reset demands	No action	Reset demands	No action
DRST_PDM	37	Reset demand peaks	No action	Reset demand peaks	No action	Reset demand peaks	No action
DRST_ENE	38	Reset energy metering	No action	Reset energy metering	No action	Reset energy metering	No action
DRST_BK	39	Reset breaker monitor	No action	Reset breaker monitor	No action	Reset breaker monitor	No action
DRST_TAR	40	Reset front-panel targets	No action	Reset front panel targets	No action	Reset front panel targets	No action
SINGEVE	41	Single-Event	No action	Single-Event	No Action	Single-Event	No Action
DRST_MML	42	Reset min/max metering	No action	Reset min/max metering	No action	Reset min/max metering	No Action
DRST_HIS	–	Reset history	No action	Reset history	No action	Reset history	No Action
DRST_HAL	–	Reset HALARM	No action	Reset HALARM	No action	Reset HALARM	No action
DRSTDNPE	–	Reset DNP3 Event Registers/Buffers	No action	Reset DNP3 Event Registers/Buffers	No action	Reset DNP3 Event Registers/Buffers	No action
RB17–RB32	44–59	Set RB17–RB32	Clear RB17–RB32	Set RB17–RB32	Clear RB17–RB32	Pulse RB17–RB32	Clear RB17–RB32
RB17:RB18	60	Pulse RB18	Pulse RB17	Pulse RB18	Pulse RB17	Pulse RB18	Pulse RB17
RB19:RB20	61	Pulse RB20	Pulse RB19	Pulse RB20	Pulse RB19	Pulse RB20	Pulse RB19
RB21:RB22	62	Pulse RB22	Pulse RB21	Pulse RB22	Pulse RB21	Pulse RB22	Pulse RB21
RB23:RB24	63	Pulse RB24	Pulse RB23	Pulse RB24	Pulse RB23	Pulse RB24	Pulse RB23
RB25:RB26	64	Pulse RB26	Pulse RB25	Pulse RB26	Pulse RB25	Pulse RB26	Pulse RB25
RB27:RB28	65	Pulse RB28	Pulse RB27	Pulse RB28	Pulse RB27	Pulse RB28	Pulse RB27
RB29:RB30	66	Pulse RB30	Pulse RB29	Pulse RB30	Pulse RB29	Pulse RB30	Pulse RB29
RB31:RB32	67	Pulse RB32	Pulse RB31	Pulse RB32	Pulse RB31	Pulse RB32	Pulse RB31
NXTEVE	68	Load-Event FIFO Mode	Load-Event LIFO Mode	Load-Event FIFO Mode	Load-Event LIFO Mode	Load-Event FIFO Mode	Load-Event LIFO Mode

NOTE: In Table E.8, index numbers are provided as a reference to aid in the conversion of settings from the SEL-651R-0, -1 to the SEL-651R-2.

If the Trip bit is set, a Latch Off operation is performed on the specified point. If the Close bit is set, a Latch On operation is performed. The Status field is used exactly as defined. All other fields are ignored. A pulse operation is asserted for a single processing interval. Note that the relay supports simultaneous pulse operations on multiple control points, but these may not occur on the same processing interval. You can perform a maximum of ten operations for a single command. For any attempt in excess of ten operations, the relay will respond with Control Status Code 08 (too many objects).

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Control Point Operation

You can define any two RB points as a pair for Trip/Close or Code Selection operations with Object 12 (control relay output block) command messages. The SEL-651R-2 assigns some special operations to the code portion of the control relay output block command. Because the SEL-651R-2 allows only one control bit to be pulsed at a time, you should send consecutive control bits in consecutive messages. Pulse operations provide a pulse with duration of one processing interval.

Analog Inputs

NOTE: Dead band changes via Object 34 are stored in volatile memory. Make sure to reissue the Object 34 dead band changes you wish to retain after a change to DNP3 port settings, issuing a **STA C** command, or a relay cold start (power cycle).

Analog inputs (30) and analog change events (32) are supported as defined in *Table E.10* and *Table E.11*. Analog values are reported in primary units. See *Appendix G: Analog Quantities* for a list of all available analog inputs and the DNP3 reference map for default scaling and dead bands. A dead band check is done after any scaling has been applied. Event class messages are generated whenever an input changes beyond the value given by the appropriate dead band setting. The voltage and current phase angles will only generate an event if, in addition to their dead band check, the corresponding magnitude changes beyond its own dead band. Analog inputs are scanned at approximately a 1 second rate, except for the Fault analog inputs discussed in *Relay Event Data*. The ANADBA and DECPLA settings apply to the current values. The ANADBV and DECPLV settings apply to the voltage values. ANADBA, ANADBV, and ANADBM shall not be applied to the fault analog inputs. All values related to a fault shall be updated cohesively regardless of the dead bands. All events generated during a scan will use the time the scan was initiated.

Relay Event Data

The following fault analog inputs are derived from the history queue data for the most recently read event: FTYPE, FTYPE16, FLOC, FI, FIA, FIB, FIC, FIG, FIN, FIQ, FFREQ, FGRP, FSHO, FTIMEH, FTIMEM, FTIMEL, FTIMEH16, FTIMEM16, FTIMEL16, and FUNR. These quantities, also referred to as the event registers, generate DNP3 analog change events (Object 32). Because these event registers refer to the same event summary record, the relay creates analog change events for all of these event registers when any one of the registers exceeds its dead band. Events for these inputs will use the time the scan was initiated. Current quantities FI, FIA, FIB, FIC, FIG, FIN, and FIQ are populated with currents from the maximum fault row.

Analog input FLOC is the fault location value. If this field contains "$$$$$$" (undetermined location) or is blank (when EFLOC := N), the relay will set the internal value of FLOC to –999.9 for DNP3. As with most of the event register values, FLOC is subject to scaling by the DECPLM setting (1 by default). So by default, a DNP3 poll of this value under the above conditions would yield a value of –9999.0 at the master. This value was chosen to represent an undetermined or blank FLOC that would not create nuisance alarms by presenting an over-range value to a DNP3 master. Note that if DECPLM is changed, this will change the end value of this point at the DNP3 master. If DECPLM is changed, you should set per-point scaling to 1 for FLOC to override the DECPLM scaling and ensure that it is transmitted as expected.

Analog input FUNR is derived from the history queue. Analog input FTYPE is a 16-bit composite value, as defined in *Table E.12* and *Table E.13* and the accompanying language.

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Settings Data

Analog inputs 51PJP, 51PKP, 51N1JP, 51N1KP, 51N2JP, 51N2KP, 51G1JP, 51G1KP, 51G2JP, 51G2KP, 51QJP, 51QKP, 51AJP, 51AKP, 51BJP, 51BKP, 51CJP, 51CKP, 51PJP_P, 51PKP_P, 51N1JP_P, 51N1KP_P, 51N2JP_P, 51N2KP_P, 51G1JP_P, 51G1KP_P, 51G2JP_P, 51G2KP_P, 51QJP_P, 51QKP_P, 51AJP_P, 51AKP_P, 51BJP_P, 51BKP_P, 51CJP_P, and 51CKP_P are derived from the present active Group settings. If the associated setting is set to off, the value will be reported as –1. Please note that these values are subject to scaling by the DECPLA setting (i.e., you will see a value of –10 for OFF with the default DECPLA setting.) You can override the default scaling by applying per-point scaling to these values in a custom DNP3 map.

Testing

Use the **TEST DB** command to temporarily force the relay to send fixed analog and/or digital values over communications interfaces for DNP3 testing (see *TEST DB Command on page 10.76*).

DNP3 Documentation

The DNP3 Device Profile XML document, available on the supplied CD or as a download from the SEL website, contains the standard device profile information for the SEL-651R-2. Please refer to this document for complete information on the DNP3 Protocol support in the SEL-651R-2.

Device Profile

Table E.9 contains the standard DNP3 device profile information. Rather than check boxes in the example Device Profile in the DNP3 Subset Definitions, only the relevant selections are shown.

Table E.9   SEL-651R-2 DNP3 Device Profile (Sheet 1 of 2)

Parameter	Value
Vendor name	Schweitzer Engineering Laboratories
Device name	SEL-651R-2 Recloser Control
Highest DNP3 request level	Level 2
Highest DNP3 response level	Level 2
Device function	Outstation
Notable objects, functions, and/or qualifiers supported	Virtual Terminal, Analog Dead Band Objects (Object 34)
Maximum data link frame size transmitted	292
Maximum data link frame size received (octets)	292
Maximum data link retries	Configurable, range 0–15
Requires data link layer confirmation	Configurable by setting
Maximum application fragment size transmitted/received (octets)	Configurable by setting
Maximum application layer retries	None
Requires application layer confirmation	When reporting Event Data
Data link confirm time-out	Configurable
Complete application fragment time-out	None
Application confirm time-out	Configurable
Complete Application response time-out	None

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Table E.9   SEL-651R-2 DNP3 Device Profile (Sheet 2 of 2)

Parameter	Value
Executes control WRITE binary outputs	Always
Executes control SELECT/OPERATE	Always
Executes control DIRECT OPERATE	Always
Executes control DIRECT OPERATE-NO ACK	Always
Executes control count greater than 1	Never
Executes control Pulse On	Always
Executes control Pulse Off	Always
Executes control Latch On	Always
Executes control Latch Off	Always
Executes control Queue	Never
Executes control Clear Queue	Never
Reports binary input change events when no specific variation requested	Only time-tagged
Reports time-tagged binary input change events when no specific variation requested	Binary Input change with time
Sends unsolicited responses	Configurable with unsolicited message enable settings. Increases retry time (configurable) when a maximum retry setting is exceeded.
Sends static data in unsolicited responses	Never
Default counter object/variation	Object 20, Variation 6
Counter roll-over	16 bits
Sends multifragment responses	Yes

In response to the delay measurement function code, the SEL-651R-2 will return a time delay accurate to within 25 milliseconds at 9600 bps. Accuracy improves with higher data rates.

Object List

Table E.10 lists the objects and variations with supported function codes and qualifier codes available in the SEL-651R-2. The list of supported objects conforms to the format laid out in the DNP3 specifications and includes both supported and unsupported objects. Those that are supported include the function and qualifier codes. The objects that are not supported are shown without any corresponding function and qualifier codes.

Table E.10   SEL-651R-2 DNP3 Object List (Sheet 1 of 6)

Obj.	Var.	Description	Request[a] Funct. Codes[c]	Request[a] Qual. Codes[d]	Response[b] Funct. Codes[c]	Response[b] Qual. Codes[d]
0	211	Device Attributes—User-specific sets of attributes	1	0, 6	129	0, 17
0	212	Device Attributes—Master data set prototypes	1	0, 6	129	0, 17
0	213	Device Attributes—Outstation data set prototypes	1	0, 6	129	0, 17
0	214	Device Attributes—Master data sets	1	0, 6	129	0, 17
0	215	Device Attributes—Outstation data sets	1	0, 6	129	0, 17
0	216	Device Attributes—Max binary outputs per request	1	0, 6	129	0, 17
0	219	Device Attributes—Support for analog output events	1	0, 6	129	0, 17
0	220	Device Attributes—Max analog output index	1	0, 6	129	0, 17
0	221	Device Attributes—Number of analog outputs	1	0, 6	129	0, 17

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Table E.10   SEL-651R-2 DNP3 Object List (Sheet 2 of 6)

Obj.	Var.	Description	Request[a]		Response[b]	
			Funct. Codes[c]	Qual. Codes[d]	Funct. Codes[c]	Qual. Codes[d]
0	222	Device Attributes—Support for binary output events	1	0, 6	129	0, 17
0	223	Device Attributes—Max binary output index	1	0, 6	129	0, 17
0	224	Device Attributes—Number of binary outputs	1	0, 6	129	0, 17
0	225	Device Attributes—Support for frozen counter events	1	0, 6	129	0, 17
0	226	Device Attributes—Support for frozen counters	1	0, 6	129	0, 17
0	227	Device Attributes—Support for counter events	1	0, 6	129	0, 17
0	228	Device Attributes—Max counter index	1	0, 6	129	0, 17
0	229	Device Attributes—Number of counters	1	0, 6	129	0, 17
0	230	Device Attributes—Support for frozen analog inputs	1	0, 6	129	0, 17
0	231[e]	Device Attributes—Support for analog input events	1	0, 6	129	0, 17
0	232	Device Attributes—Max analog input index	1	0, 6	129	0, 17
0	233	Device Attributes—Number of analog inputs	1	0, 6	129	0, 17
0	234	Device Attributes—Support for double-bit events	1	0, 6	129	0, 17
0	235	Device Attributes—Max double-bit binary index	1	0, 6	129	0, 17
0	236	Device Attributes—Number of double-bit binaries	1	0, 6	129	0, 17
0	237	Device Attributes—Support for binary input events	1	0, 6	129	0, 17
0	238	Device Attributes—Max binary input index	1	0, 6	129	0, 17
0	239	Device Attributes—Number of binary inputs	1	0, 6	129	0, 17
0	240	Device Attributes—Max transmit fragment size	1	0, 6	129	0, 17
0	241	Device Attributes—Max receive fragment size	1	0, 6	129	0, 17
0	242	Device Attributes—Device manufacturer's software version (FID string)	1	0, 6	129	0, 17
0	243	Device Attributes—Device manufacturer's hardware version (Part number)	1	0, 6	129	0, 17
0	245	Device Attributes—User-assigned location name (TID setting)	1	0, 6	129	0, 17
0	246	Device Attributes—User-assigned ID code/ number (RID setting)	1	0, 6	129	0, 17
0	247	Device Attributes—User-assigned device name (RID setting)	1	0, 6	129	0, 17
0	248	Device Attributes—Device serial number	1	0, 6	129	0, 17
0	249	Device Attributes—DNP3 subset and conformance (e.g., "2:2009")	1	0, 6	129	0, 17
0	250	Device Attributes—Device manufacturer's product name and model (e.g., "SEL-651RA Relay")	1	0, 6	129	0, 17
0	252	Device Attributes—Device manufacturer's name ("SEL")	1	0, 6	129	0, 17
0	254	Device Attributes—Nonspecific all attributes request	1	0, 6	129	0, 17
0	255	Device Attributes—List of attribute variations	1	0, 6	129	0, 17
1	0	Binary Input—All Variations	1, 22	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
1	1	Binary Input	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
1	2[e]	Binary Input With Status	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
2	0	Binary Input Change—All Variations	1	6, 7, 8		
2	1	Binary Input Change Without Time	1	6, 7, 8	129	17, 28

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Table E.10 SEL-651R-2 DNP3 Object List (Sheet 3 of 6)

Obj.	Var.	Description	Request[a]		Response[b]	
			Funct. Codes[c]	Qual. Codes[d]	Funct. Codes[c]	Qual. Codes[d]
2	2[e]	Binary Input Change With Time	1	6, 7, 8	129,130	17, 28
2	3	Binary Input Change With Relative Time	1	6, 7, 8	129	17, 28
10	0	Binary Output—All Variations	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
10	1	Binary Output				
10	2[e]	Binary Output Status	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
12	0	Control Block—All Variations				
12	1	Control Relay Output Block	3, 4, 5, 6	17, 28	129	echo of request
12	2	Pattern Control Block	3, 4, 5, 6	7	129	echo of request
12	3	Pattern Mask	3, 4, 5, 6	0, 1	129	echo of request
20	0	Binary Counter—Any Variation	1, 22	0, 1, 6, 7, 8, 17, 28		
20	0	Binary Counter—Any Variation	7, 8, 9, 10[f]	0, 1, 6, 7, 8		
20	1	32-Bit Binary Counter	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
20	2	16-Bit Binary Counter	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
20	3	32-Bit Delta Counter				
20	4	16-Bit Delta Counter				
20	5	32-Bit Binary Counter Without Flag	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
20	6[e]	16-Bit Binary Counter Without Flag	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
20	7	32-Bit Delta Counter Without Flag				
20	8	16-Bit Delta Counter Without Flag				
21[g]	0	Frozen Counter—All Variations	1		129	
21[g]	1	32-Bit Frozen Counter	1		129	
21[g]	2	16-Bit Frozen Counter	1		129	
21[g]	3	32-Bit Frozen Delta Counter	1		129	
21[g]	4	16-Bit Frozen Delta Counter	1		129	
21[g]	5	32-Bit Frozen Counter With Time of Freeze	1		129	
21[g]	6	16-Bit Frozen Counter With Time of Freeze	1		129	
21[g]	7	32-Bit Frozen Delta Counter With Time of Freeze	1		129	
21[g]	8	16-Bit Frozen Delta Counter With Time of Freeze	1		129	
21[g]	9	32-Bit Frozen Counter Without Flag	1		129	
21[g]	10	16-Bit Frozen Counter Without Flag	1		129	
21[g]	11	32-Bit Frozen Delta Counter Without Flag				
21[g]	12	16-Bit Frozen Delta Counter Without Flag				
22	0	Counter Change Event—All Variations	1	6, 7, 8		
22	1	32-Bit Counter Change Event Without Time	1	6, 7, 8	129	17, 28

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Table E.10   SEL-651R-2 DNP3 Object List (Sheet 4 of 6)

Obj.	Var.	Description	Request[a]		Response[b]	
			Funct. Codes[c]	Qual. Codes[d]	Funct. Codes[c]	Qual. Codes[d]
22	2[e]	16-Bit Counter Change Event Without Time	1	6, 7, 8	129,130	17, 28
22	3	32-Bit Delta Counter Change Event Without Time				
22	4	16-Bit Delta Counter Change Event Without Time				
22	5	32-Bit Counter Change Event With Time	1	6, 7, 8	129	17, 28
22	6	16-Bit Counter Change Event With Time	1	6, 7, 8	129	17, 28
22	7	32-Bit Delta Counter Change Event With Time				
22	8	16-Bit Delta Counter Change Event With Time				
23	0	Frozen Counter Event—All Variations				
23	1	32-Bit Frozen Counter Event Without Time				
23	2	16-Bit Frozen Counter Event Without Time				
23	3	32-Bit Frozen Delta Counter Event Without Time				
23	4	16-Bit Frozen Delta Counter Event Without Time				
23	5	32-Bit Frozen Counter Event With Time				
23	6	16-Bit Frozen Counter Event With Time				
23	7	32-Bit Frozen Delta Counter Event With Time				
23	8	16-Bit Frozen Delta Counter Event With Time				
30	0	Analog Input—All Variations	1, 22	0, 1, 6, 7, 8, 17, 28		
30	1	32-Bit Analog Input	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
30	2	16-Bit Analog Input	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
30	3	32-Bit Analog Input Without Flag	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
30	4	16-Bit Analog Input Without Flag	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
30	5	Short Floating Point Analog Input	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
30	6	Long Floating Point Analog Input	1	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
31	0	Frozen Analog Input—All Variations				
31	1	32-Bit Frozen Analog Input				
31	2	16-Bit Frozen Analog Input				
31	3	32-Bit Frozen Analog Input With Time of Freeze				
31	4	16-Bit Frozen Analog Input With Time of Freeze				
31	5	32-Bit Frozen Analog Input Without Flag				
31	6	16-Bit Frozen Analog Input Without Flag				
32	0	Analog Change Event—All Variations	1	6, 7, 8		
32	1	32-Bit Analog Change Event Without Time	1	6, 7, 8	129	17, 28
32	2[e]	16-Bit Analog Change Event Without Time	1	6, 7, 8	129,130	17, 28
32	3	32-Bit Analog Change Event With Time	1	6, 7, 8	129	17, 28

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Table E.10   SEL-651R-2 DNP3 Object List (Sheet 5 of 6)

Obj.	Var.	Description	Request[a]		Response[b]	
			Funct. Codes[c]	Qual. Codes[d]	Funct. Codes[c]	Qual. Codes[d]
32	4	16-Bit Analog Change Event With Time	1	6, 7, 8	129	17, 28
32	5	Short Floating Point Analog Change Event	1	6, 7, 8	129	17, 28
32	6	Long Floating Point Analog Change Event	1	6, 7, 8	129	17, 28
32	7	Short Floating Point Analog Change Event With Time	1	6, 7, 8	129	17, 28
32	8	Long Floating Point Analog Change Event With Time	1	6, 7, 8	129	17, 28
33	0	Frozen Analog Event—All Variations				
33	1	32-Bit Frozen Analog Event Without Time				
33	2	16-Bit Frozen Analog Event Without Time				
33	3	32-Bit Frozen Analog Event With Time				
33	4	16-Bit Frozen Analog Event With Time				
33	5	Short Floating Point Frozen Analog Event				
33	6	Long Floating Point Frozen Analog Event				
33	7	Short Floating Point Frozen Analog Event With Time				
33	8	Long Floating Point Frozen Analog Event With Time				
34	0	Analog Dead Band—All Variations				
34	1[e]	16-Bit Analog Dead Band	1, 2	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
34	2	32-Bit Analog Dead Band	1, 2	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
34	3	Short Floating Point Dead Band	1, 2	0, 1, 6, 7, 8, 17, 28	129	0, 1, 17, 28
40	0	Analog Output Status—All Variations	1	0, 1, 6, 7, 8		
40	1	32-Bit Analog Output Status	1	0, 1, 6, 7, 8	129	0, 1, 17, 28
40	2[e]	16-Bit Analog Output Status	1	0, 1, 6, 7, 8	129	0, 1, 17, 28
40	3	Short Floating Point Analog Output Status	1	0, 1, 6, 7, 8	129	0, 1, 17, 28
40	4	Long Floating Point Analog Output Status	1	0, 1, 6, 7, 8	129	0, 1, 17, 28
41	0	Analog Output Block—All Variations				
41	1	32-Bit Analog Output Block	3, 4, 5, 6	17, 28	129	echo of request
41	2	16-Bit Analog Output Block	3, 4, 5, 6	17, 28	129	echo of request
41	3	Short Floating Point Analog Output Block	3, 4, 5, 6	17, 28	129	echo of request
41	4	Long Floating Point Analog Output Block	3, 4, 5, 6	17, 28	129	echo of request
50	0	Time and Date—All Variations				
50	1	Time and Date	1, 2	7, 8 index = 0	129	07, quantity=1
50	2	Time and Date With Interval				
50	3	Time and Date (Last Recorded Time)	2	7 (quantity=1)	129	
51	0	Time and Date CTO—All Variations				
51	1	Time and Date CTO			129	07, quantity=1
51	2	Unsynchronized Time and Date CTO			129	07, quantity=1
52	0	Time Delay—All Variations				

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Table E.10   SEL-651R-2 DNP3 Object List (Sheet 6 of 6)

Obj.	Var.	Description	Request[a]		Response[b]	
			Funct. Codes[c]	Qual. Codes[d]	Funct. Codes[c]	Qual. Codes[d]
52	1	Time Delay Coarse				
52	2	Time Delay Fine			129	07, quantity=1
60	0	All Classes of Data	1, 20, 21	6		
60	1	Class 0 Data	1, 22	6		
60	2	Class 1 Data	1, 20, 21, 22	6, 7, 8		
60	3	Class 2 Data	1, 20, 21, 22	6, 7, 8		
60	4	Class 3 Data	1, 20, 21, 22	6, 7, 8		
70	1	File Identifier				
70	2	Authentication Object				
70	3	File Command Object				
70	4	File Command Status Object				
70	5	File Transport Object				
70	6	File Transport Status Object				
70	7	File Descriptor Object				
80	1	Internal Indications	2	0, 1 index=7		
81	1	Storage Object				
82	1	Device Profile				
83	1	Private Registration Object				
83	2	Private Registration Object Descriptor				
90	1	Application Identifier				
100	1	Short Floating Point				
100	2	Long Floating Point				
100	3	Extended Floating Point				
101	1	Small Packed Binary-Coded Decimal				
101	2	Medium Packed Binary-Coded Decimal				
101	3	Large Packed Binary-Coded Decimal				
110	all	Octet String				
111	all	Octet String Event				
112	all	Virtual Terminal Output Block	2	6	129	
113	all	Virtual Terminal Event Data	1	6	129, 130	17, 28
N/A		No object required for the following function codes: 13 cold start 14 warm start 23 delay measurement	13, 14, 23			

[a] Supported in requests from master.
[b] May generate in response to master.
[c] Decimal.
[d] Hexadecimal.
[e] Default variation.
[f] The relay accepts function codes 7, 8, 9, and 10 and responds without an error, but no action is taken because frozen counters are not supported.
[g] DNP3 implementation Level 2 functionality, which the relay does not support.

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Reference Data Map

Table E.11 shows the SEL-651R-2 reference data map. The reference map shows the data available to a DNP3 master. You can use the default map or the custom DNP3 mapping functions of the SEL-651R-2 to retrieve only the points required by your application.

To retrieve SER-quality binary inputs, SEL-651R-0, -1 models required mapping points within the range of indexes (800–999/1000–1199) dedicated to SER inputs. This is not necessary for the SEL-651R-2 recloser control. If a point is registered in the SER, it will automatically have an SER time stamp when included in the default or custom data map.

The relay scales analog values by the indicated settings or fixed scaling indicated in the description. Analog dead bands for event reporting use the indicated settings, or ANADBM if you have specified no setting.

Table E.11   DNP3 Reference Data Map (Sheet 1 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
01,02	Relay Word	Relay Word Bit label	000–799 (651R-0) 000–999 (651R-1)
01,02	Relay Word	SER indices derived from SER trigger settings SER1–SER4	800–999 (651R-0) 1000–1199 (651R-1)
01,02	TLED_01–TLED_16	Relay front-panel targets (01–16), product specific meaning	1600–1615
01,02	RLYDIS	Relay disabled	1616
01,02	STFAIL	Relay diagnostic failure	1617
01,02	STWARN	Relay diagnostic warning	1618
01,02	UNRDEV	An unread relay event is available	1619
01,02	STSET	Settings change or relay restart	1620
01,02	LDPFA	Power factor leading for A-phase	1632
01,02	LDPFB	Power factor leading for B-phase	1633
01,02	LDPFC	Power factor leading for C-phase	1634
01,02	LDPF3	Power factor leading for three-phase	1635
01,02	TLED_17–TLED_24	Relay front-panel targets (17–24), product specific meaning	1636–1643
01,02	NUNREV	A more recent unread relay event is available	1644
10,12	RB01–RB16	Remote bits RB01–RB16	00–15
10,12	OC3	Pulse Open Breaker OC3 (Breaker 1, 3-pole)	16
10,12	CC3	Pulse Close Breaker CC3 (Breaker 1, 3-pole)	17
10,12	OCA	Pulse Open Command OCA (Breaker 1, Phase A)	18
10,12	CCA	Pulse Close Command CCA (Breaker 1, Phase A)	19
10,12	OCB	Pulse Open Command OCB (Breaker1, Phase B)	20
10,12	CCB	Pulse Close Command CCB (Breaker 1, Phase B)	21
10,12	OCC	Pulse Open Command OCC (Breaker 1, Phase C)	22
10,12	CCC	Pulse Close Command CCC (Breaker 1, Phase C)	23
10,12	RB01:RB02, RB03:RB04, RB05:RB06, RB07:RB08, RB09:RB10, RB11:RB12, RB13:RB14, RB15:RB16	Remote bit pairs RB01–RB16	24–31
10,12	OC3:CC3	Open/Close pair OC3 and CC3 (Breaker 1, 3-pole)	32
10,12	OCA:CCA	Open/Close pair OCA and CCA (Breaker 1, Phase A)	33

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Table E.11 DNP3 Reference Data Map (Sheet 2 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
10,12	OCB:CCB	Open/Close pair OCB and CCA (Breaker 1, Phase B)	34
10,12	OCC:CCC	Open/Close pair OCC and CCC (Breaker 1, Phase C)	35
10,12	DRST_DEM	Reset demands	36
10,12	DRST_PDM	Reset peak demands	37
10,12	DRST_ENE	Reset energies	38
10,12	DRST_BK	Reset breaker monitor	39
10,12	DRST_TAR	Reset front-panel targets	40
10,12	SINGEVE	Single Event	41
10,12	DRST_MML	Reset Max/Min	42
10,12	DRST_HIS	Reset history	–
10,12	DRST_HAL	Reset HALARM	–
10,12	DRSTDNPE	Reset DNP Event Registers/Buffers	–
10,12	RB17–RB32	Remote bits RB17–RB32	44–59
10,12	RB17:RB18, RB19:RB20, RB21:RB22, RB23:RB24, RB25:RB26, RB27:RB28, RB29:RB30, RB31:RB32	Remote bit pairs RB17–RB32	60–67
10,12	NXTEVE	Load Event	68
20,22	ACTGRP	Active settings group (Read)	00
20,22	INTTA	Internal breaker trips—Phase A	01
20,22	INTTB	Internal breaker trips—Phase B	02
20,22	INTTC	Internal breaker trips—Phase C	03
20,22	EXTTA	External breaker trips—Phase A	04
20,22	EXTTB	External breaker trips—Phase B	05
20,22	EXTTC	External breaker trips—Phase C	06
20,22	FUNR	Number of unread fault event reports	07
20,22	OPSCTRA	Total number of internal and external trips—Phase A	–
20,22	OPSCTRB	Total number of internal and external trips—Phase B	–
20,22	OPSCTRC	Total number of internal and external trips—Phase C	–
20,22	SC01–SC16	SELOGIC Counters 1–16	11–26
30,32,34	IA, IAFA[a]	IA magnitude and angle	00,01
30,32,34	IB, IBFA[a]	IB magnitude and angle	02,03
30,32,34	IC, ICFA[a]	IC magnitude and angle	04,05
30,32,34	IN, INFA[a]	IN magnitude and angle	06,07
30,32,34	IG, IGFA[a]	IG magnitude and angle	34,35
30,32,34	VAY, VAYFA[b]	VAY magnitude (kV) and angle	36,37
30,32,34	VBY, VBYFA[b]	VBY magnitude (kV) and angle	38,39
30,32,34	VCY, VCYFA[b]	VCY magnitude (kV) and angle	40,41
30,32,34	VAZ, VAZFA[b]	VAZ magnitude (kV) and angle	42,43
30,32,34	VBZ, VBZFA[b]	VBZ magnitude (kV) and angle	44,45
30,32,34	VCZ, VCZFA[b]	VCZ magnitude (kV) and angle	46,47

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Table E.11   DNP3 Reference Data Map (Sheet 3 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
30,32,34	VABY, VABYFA[b]	VABY magnitude (kV) and angle	–
30,32,34	VBCY, VBCYFA[b]	VBCY magnitude (kV) and angle	–
30,32,34	VCAY, VCAYFA[b]	VCAY magnitude (kV) and angle	–
30,32,34	VABZ, VABZFA[b]	VABZ magnitude (kV) and angle	–
30,32,34	VBCZ, VBCZFA[b]	VBCZ magnitude (kV) and angle	–
30,32,34	VCAZ, VCAZFA[b]	VCAZ magnitude (kV) and angle	–
30,32,34	3I0, 3I0FA[a]	3I0 magnitude and angle	48,49
30,32,34	I1, I1FA[a]	I1 magnitude and angle	50,51
30,32,34	3I2, 3I2FA[a]	3I2 magnitude and angle	52,53
30,32,34	3V0Y, 3V0YFA[b]	3V0Y magnitude (kV) and angle	72,73
30,32,34	V1Y, V1YFA[b]	V1Y magnitude (kV) and angle	74,75
30,32,34	V2Y, V2YFA[b]	V2Y magnitude (kV) and angle	76,77
30,32,34	3V0Z, 3V0ZFA[b]	3V0Z magnitude (kV) and angle	78,79
30,32,34	V1Z, V1ZFA[b]	V1Z magnitude (kV) and angle	80,81
30,32,34	V2Z, V2ZFA[b]	V2Z magnitude (kV) and angle	82,83
30,32,34	MWA[c], MWB[c], MWC[c], MW3[c]	MW A-, B-, C- and three-phase	84–87
30,32,34	MVARA[c], MVARB[c], MVARC[c], MVAR3[c]	MVAR A-, B-, C- and three-phase	88–91
30,32,34	PFA[c], PFB[c], PFC[c], PF3[c]	Power factor A-, B-, C- and three-phase	92–95
30,32,34	FREQ[d]	Frequency	104
30,32,34	TEMP[e]	Relay Internal Temperature	105
30,32,34	MWHAI[c], MWHAO[c]	A-phase MWhr in and out	106,107
30,32,34	MWHBI[c], MWHBO[c]	B-phase MWhr in and out	108,109
30,32,34	MWHCI[c], MWHCO[c]	C-phase MWhr in and out	110,111
30,32,34	MWH3I[c], MWH3O[c]	Three-phase MWhr in and out	112,113
30,32,34	MVRHAI[c], MVRHAO[c]	A-phase MVARhr in and out	114,115
30,32,34	MVRHBI[c], MVRHBO[c]	B-phase MVARhr in and out	116,117
30,32,34	MVRHCI[c], MVRHCO[c]	C-phase MVARhr in and out	118,119
30,32,34	MVRH3I[c], MVRH3O[c]	Three-phase MVARhr in and out	120,121
30,32,34	IADEM[a], IBDEM[a], ICDEM[a], IGDEM[a], 3I2DEM[a]	Demand IA, IB, IC, IG (IN or 3I0), and 3I2 magnitudes	122–126
30,32,34	INDEM[a]	Demand IN magnitude	127
30,32,34	MWADI[c], MWBDI[c], MWCDI[c], MW3DI[c]	A-, B-, C- and three-phase demand MW in	128–131
30,32,34	MVRADI[c], MVRBDI[c], MVRCDI[c], MVR3DI[c]	A-, B-, C- and three-phase demand MVAR in	132–135
30,32,34	MWADO[c], MWBDO[c], MWCDO[c], MW3DO[c]	A-, B-, C- and three-phase demand MW out	136–139
30,32,34	MVRADO[c], MVRBDO[c], MVRCDO[c], MVR3DO[c]	A-, B-, C- and three-phase demand MVAR out	140–143

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Table E.11 DNP3 Reference Data Map (Sheet 4 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
30,32,34	IAPK[a], IBPK[a], ICPK[a], IGPK[a], 3I2PK[a]	Peak demand IA, IB, IC, IG (IN or 3I0), and 3I2 magnitudes	144–148
30,32,34	INPK[a]	Peak demand IN magnitude	149
30,32,34	MWAPI[c], MWBPI[c], MWCPI[c], MW3PI[c]	A-, B-, C- and three-phase peak demand MW in	150–153
30,32,34	MVRAPI[c], MVRBPI[c], MVRCPI[c], MVR3PI[c]	A-, B-, C- and three-phase peak demand MVAR in	154–157
30,32,34	MWAPO[c], MWBPO[c], MWCPO[c], MW3PO[c]	A-, B-, C- and three-phase peak demand MW out	158–161
30,32,34	MVRAPO[c], MVRBPO[c], MVRCPO[c], MVR3PO[c]	A-, B-, C- and three-phase peak demand MVAR out	162–165
30,32,34	WEARA[f], WEARB[f], WEARC[f]	Breaker contact wear percentage (A, B, C)	166–168
30,32,34	MAXWEAR[f]	Greatest wear of WEARA, WEARB, or WEARC	–
30,32	FTYPE[f,g]	Fault type	176
30,32	FTYPE16[f,g]	Same as FTYPE, but populated to be read as a 16-bit signed value	–
30,32	FTARHI[f,g]	Fault Targets (corresponding to rows 0 and 1 of Relay Word)	177
30,32	FLOC[c,g]	Fault location	178
30,32	FFREQ[d,g]	Fault frequency	180
30,32	FGRP[f,g]	Fault settings group (1–8)	181
30,32	FSHO[f,g]	Fault recloser shot counter	182
30,32	FTIMEH[f,g], FTIMEM[f,g], FTIMEL[f,g]	Fault time in DNP format (high, middle, and low 16 bits)	184–186
30,32	FTIMEH16[f,g], FTIMEM16[f,g], FTIMEL16[f,g]	Same as FTIMEH, FTIMEM and FTIMEL, but populated to be read as 16-bit signed values	–
30,32	FI[a,g]	Maximum fault current in primary amperes	–
30,32	FIA[a,g]	Phase A Fault current in primary amperes	187
30,32	FIB[a,g]	Phase B Fault current in primary amperes	188
30,32	FIC[a,g]	Phase C Fault current in primary amperes	189
30,32	FIG[a,g]	Ground Fault current in primary amperes	190
30,32	FIQ[a,g]	Negative Sequence Fault current in primary amperes	191
30,32	FTARLO[f,g]	Fault Targets (lower 16 bits)	192
30,32	FUNR[f,g]	Number of unread fault event reports	–
30,32,34	MV01–MV64[f]	Math Variables 1–64	–
30,32,34	SC01–SC16[f]	SELOGIC Counters 1–16	–
30,32	LDPFA[f]	Power Factor Leading = 1, A-phase	–
30,32	LDPFB[f]	Power Factor Leading = 1, B-phase	–
30,32	LDPFC[f]	Power Factor Leading = 1, C-phase	–
30,32	LDPF3[f]	Power Factor Leading = 1, three-phase	–
30,32,34	MVAA[c], MVAB[c], MVAC[c], MVA3[c]	MVA for A-, B-, C- and three-phase	197–200
30,32,34	MVAAD[c], MVABD[c], MVACD[c], MVA3D[c]	MVA Demand for A-, B-, C- and three-phase	201–204

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Table E.11   DNP3 Reference Data Map (Sheet 5 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
30,32,34	MVAAP[c], MVABP[c], MVACP[c], MVA3P[c]	MVA Peak Demand for A-, B-, C- and three-phase	205–208
30,32,34	IAMIN[a,h], IBMIN[a,h], ICMIN[a,h], INMIN[a,h], IGMIN[a,h]	Minimum IA, IB, IC, IN, IG (IN or 3I0) magnitudes	209–213
30,32,34	VAYMIN[b,h], VBYMIN[b,h], VCYMIN[b,h], VAZMIN[b,h], VBZMIN[b,h], VCZMIN[b,h]	Minimum VAY, VBY, VCY, VAZ, VBZ, VCZ magnitudes (kV)	214–219
30,32,34	MW3MIN[c,h]	Minimum MW three-phase magnitude	223
30,32,34	MVR3MIN[c,h]	Minimum MVAR three-phase magnitude	227
30,32,34	MVA3MIN[c,h]	Minimum MVA three-phase magnitude	231
30,32,34	IAMAX[a,h], IBMAX[a,h], ICMAX[a,h], INMAX[a,h], IGMAX[a,h]	Maximum IA, IB, IC, IN, IG (IN or 3I0) magnitudes	232–236
30,32,34	VAYMAX[b,h], VBYMAX[b,h], VCYMAX[b,h], VAZMAX[b,h], VBZMAX[b,h], VCZMAX[b,h]	Maximum VAY, VBY, VCY, VAZ, VBZ, VCZ magnitudes (kV)	237–242
30,32,34	MW3MAX[c,h]	Maximum MW three-phase magnitude	246
30,32,34	MVR3MAX[c,h]	Maximum MVAR three-phase magnitude	250
30,32,34	MVA3MAX[c,h]	Maximum MVA three-phase magnitude	254
30,32,34	IAR[a], IBR[a], ICR[a], INR[a]	RMS IA, IB, IC, IN magnitudes	255–258
30,32,34	VAYR[b], VBYR[b], VCYR[b], VAZR[b], VBZR[b], VCZR[b]	RMS VAY, VBY, VCY, VAZ, VBZ, VCZ magnitudes	259–264
30,32,34	MWAR[c], MWBR[c], MWCR[c], MW3R[c]	RMS MWA, MWB, MWC, MW3 phase magnitudes	265–268
30,32,34	IAHT[c], IBHT[c], ICHT[c], INHT[c]	THD IA, IB, IC, IN (percent)	290–293
30,32,34	VAYHT[c], VBYHT[c], VCYHT[c], VAZHT[c], VBZHT[c], VCZHT[c]	THD VAY, VBY, VCY, VAZ, VBZ, VCZ (percent)	294–299
30,32,34	IAH01[a]	Harmonics IA Fundamental	300
30,32,34	IAH02–IAH15[c]	Harmonics IA 2nd–15th (as percent of fundamental)	301–314
30,32,34	IAH16[c]	Harmonic IA 16th (as percent of fundamental)	–
30,32,34	IBH01[a]	Harmonics IB Fundamental	315
30,32,34	IBH02–IBH15[c]	Harmonics IB 2nd–15th (as percent of fundamental)	316–329
30,32,34	IBH16[c]	Harmonic IB 16th (as percent of fundamental)	–
30,32,34	ICH01[a]	Harmonics IC Fundamental	330
30,32,34	ICH02–ICH15[c]	Harmonics IC 2nd–15th (as percent of fundamental)	331–344
30,32,34	ICH16[c]	Harmonic IC 16th (as percent of fundamental)	–
30,32,34	INH01[a]	Harmonics IN Fundamental	345
30,32,34	INH02–INH15[c]	Harmonics IN 2nd–15th (as percent of fundamental)	346–359
30,32,34	INH16[c]	Harmonic IN 16th (as percent of fundamental)	–
30,32,34	VAYH01[b]	Harmonics VAY Fundamental (kV)	390
30,32,34	VAYH02–VAYH15[c]	Harmonics VAY 2nd–15th (as percent of fundamental)	391–404
30,32,34	VAYH16[c]	Harmonics VAY 16th (as percent of fundamental)	–

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Object Type	Label	Description	SEL-651R-0/1 Index
30,32,34	VBYH01[b]	Harmonics VBY Fundamental (kV)	405
30,32,34	VBYH02–VBYH15[c]	Harmonics VBY 2nd–15th (as percent of fundamental)	406–419
30,32,34	VBYH16[c]	Harmonic VBY 16th (as percent of fundamental)	–
30,32,34	VCYH01[b]	Harmonics VCY Fundamental (kV)	420
30,32,34	VCYH02–VCYH15[c]	Harmonics VCY 2nd–15th (as percent of fundamental)	421–434
30,32,34	VCYH16[c]	Harmonic VCY 16th (as percent of fundamental)	–
30,32,34	VAZH01[b]	Harmonics VAZ Fundamental (kV)	435
30,32,34	VAZH02–VAZH15[c]	Harmonics VAZ 2nd–15th (as percent of fundamental)	436–449
30,32,34	VAZH16[c]	Harmonic VAZ 16th (as percent of fundamental)	–
30,32,34	VBZH01[b]	Harmonics VBZ Fundamental (kV)	450
30,32,34	VBZH02–VBZH15[c]	Harmonics VBZ 2nd–15th (as percent of fundamental)	451–464
30,32,34	VBZH16[c]	Harmonic VBZ 16th (as percent of fundamental)	–
30,32,34	VCZH01[b]	Harmonics VCZ Fundamental (kV)	465
30,32,34	VCZH02–VCZH15[c]	Harmonics VCZ 2nd–15th (as percent of fundamental)	466–479
30,32,34	VCZH16[c]	Harmonic VCZ 16th (as percent of fundamental)	–
30,32,34	51PJP[a]	51PJP setting in secondary units	480
30,32,34	51PKP[a]	51PKP setting in secondary units	481
30,32,34	51N1JP[a]	51N1JP setting in secondary units	–
30,32,34	51N1KP[a]	51N1KP setting in secondary units	–
30,32,34	51N2JP[a]	51N2JP setting in secondary units	–
30,32,34	51N2KP[a]	51N2KP setting in secondary units	–
30,32,34	51G1JP[a]	51G1JP setting in secondary units	482
30,32,34	51G1KP[a]	51G1KP setting in secondary units	483
30,32,34	51G2JP[a]	51G2JP setting in secondary units	484
30,32,34	51G2KP[a]	51G2KP setting in secondary units	485
30,32,34	51QJP[a]	51QJP setting in secondary units	486
30,32,34	51QKP[a]	51QKP setting in secondary units	487
30,32,34	51AJP[a]	51AJP setting in secondary units	488
30,32,34	51AKP[a]	51AKP setting in secondary units	489
30,32,34	51BJP[a]	51BJP setting in secondary units	490
30,32,34	51BKP[a]	51BKP setting in secondary units	491
30,32,34	51CJP[a]	51CJP setting in secondary units	492
30,32,34	51CKP[a]	51CKP setting in secondary units	493
30,32,34	51PJP_P[a]	51PJP setting in primary units	–
30,32,34	51PKP_P[a]	51PKP setting in primary units	–
30,32,34	51N1JP_P[a]	51N1JP setting in primary units	–
30,32,34	51N1KP_P[a]	51N1KP setting in primary units	–
30,32,34	51N2JP_P[a]	51N2JP setting in primary units	–
30,32,34	51N2KP_P[a]	51N2KP setting in primary units	–
30,32,34	51G1JP_P[a]	51G1JP setting in primary units	–

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Table E.11   DNP3 Reference Data Map (Sheet 7 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
30,32,34	51G1KP_P[a]	51G1KP setting in primary units	–
30,32,34	51G2JP_P[a]	51G2JP setting in primary units	–
30,32,34	51G2KP_P[a]	51G2KP setting in primary units	–
30,32,34	51QJP_P[a]	51QJP setting in primary units	–
30,32,34	51QKP_P[a]	51QKP setting in primary units	–
30,32,34	51AJP_P[a]	51AJP setting in primary units	–
30,32,34	51AKP_P[a]	51AKP setting in primary units	–
30,32,34	51BJP_P[a]	51BJP setting in primary units	–
30,32,34	51BKP_P[a]	51BKP setting in primary units	–
30,32,34	51CJP_P[a]	51CJP setting in primary units	–
30,32,34	51CKP_P[a]	51CKP setting in primary units	–
30,32,34	P5V_PS[c]	+5 Volt Power Supply	494
30,32,34	P5V_REG[c]	+5 Volt Regulated Power Supply	495
30,32,34	P15V_PS[c]	+15 Volt Power Supply	499
30,32,34	N15V_PS[c]	–15 Volt Power Supply	500
30,32,34	P12V_TC[c]	+12 Volt Trip/Close Capacitors Control Supply	–
30,32,34	P5VA_PS[c]	+5 Volt Analog Power Supply	–
30,32,34	N5VA_PS[c]	–5 Volt Analog Power Supply	–
30,32,34	TBAT[c]	Battery Temperature in degrees C	505
30,32,34	CMODE[c]	Charger Mode, see *Table E.14* for definitions	506
30,32,34	VBAT[c]	Battery Voltage in Volts dc	507
30,32,34	IBAT[c]	Battery Current in amperes dc	508
30,32,34	INPBV[c]	Input Power Bus Voltage	510
30,32,34	12VAUX[c]	12 V AUX Power	511
30,32,34	TCCAPV[c]	Trip/Close Cap Voltage (TCCAPV)	512
30,32,34	BKTYP	Breaker Type, follows BKTYP Global setting	–
30,32,34	INTIA[a], INTIB[a], INTIC[a]	Internal Trip Accumulated Current IA, IB, IC	516–518
30,32,34	EXTIA[a], EXTIB[a], EXTIC[a]	External Trip Accumulated Current IA, IB, IC	519–521
30,32,34	APHTR[f], BPHTR[f], CPHTR[f], GNDCTR[f]	Involved Phase Count A, B, C, and G	522–525
30	FWREV	Relay Firmware Revision Number	526
30	FWVNUM	Relay firmware version number	–
30	REPADR	DNP Master Address	527
30	SNUMBL	Lowest 4 digits of the relay serial number	528
30	SNUMBM	Middle 4 digits of the relay serial number	529
30	SNUMBH	Highest 4 digits of the relay serial number	530
30	DNPADR	DNP Slave Address of the relay	531
40,41	ACTGRP	Active settings group (Write)	00
50		Time and Date	
60		Class Data	

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Table E.11   DNP3 Reference Data Map (Sheet 8 of 8)

Object Type	Label	Description	SEL-651R-0/1 Index
80		Internal Indications	
112		Virtual Terminal Output Block	
113		Virtual Terminal Event Data	

ᵃ Default current scaling DECPLA on magnitudes and angles multiplied by 100. Dead band ANADBA on magnitudes and ANADBM on angles.
ᵇ Default voltage scaling DECPLV on magnitudes and angles multiplied by 100. Dead band ANADBV on magnitudes and ANADBM on angles.
ᶜ Default miscellaneous scaling DECPLM and dead band ANADBM.
ᵈ Default scaling = 100 and dead band ANADBM.
ᵉ Default scaling = 100 and dead band = 1.
ᶠ Default scaling = 1 and dead band ANADBM.
ᵍ ANADBA, ANADBV, and ANADBM are not applicable to fault Analog Inputs. See Relay Event Data on page E.22 for a detailed description of the labels.
ʰ Minimum values that have been reset report the largest positive value possible. Maximum values that have been reset report the largest negative value possible.

Fault summary information (fault type, targets, location, frequency, settings group, and recloser shot counter) are available through Object 30. Depending upon setting RPEVTYP, any new trip event (TRIPA, TRIPB, TRIPC, or TRIP3P, when RPEVTYP := TRIP) or any new event (rising edge of TRIP*x* Relay Word bits, rising edge of SELOGIC control equation setting ER, **TRI** command, pulsing an output when RPEVTYP := ALL) is latched into these event registers. The event registers will be locked (they will not update) for time EVELOCK. The event registers are cleared by an assertion of the TRGTR Relay Word bit.

Object 30, Fault Type, is a 16-bit composite value, where the upper byte value indicates an event cause as shown in *Table E.12* and the lower byte indicates a fault type as shown in *Table E.13*. The upper and lower byte will be the sum of the applicable event cause and fault types. For example, a Fault Type of 3079 decimal would translate to 0C07 hex, and indicate a Trip and an ER element Event Cause ($4 + 8 = 12$ or 0C hex) on A Phase, B Phase and C Phase ($1 + 2 + 4 = 07$). If input FTYPE is 0, fault information has not yet been read and the fault analog inputs do not contain valid event data.

Table E.12   Object 30, Fault Type Upper Byte–Event Cause

Byte Value	Description
1	Trigger command
2	Pulse command
4	Trip element
8	Event report element

Table E.13   Object 30, Fault Type Lower Byte–Fault Type

Byte Value	Description
0	Indeterminate
1	A-phase
2	B-phase
4	C-phase
8	Ground

In some instances, the values in the FTIME*x* registers and FTYPE register may contain a value greater than 32767, which can be read correctly using Object 30 variation 1 or 3 (32-bit value). However, some DNP masters cannot

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read a 32-bit value, so the 16-bit variations (2 and 4) clamp the value and variation 2 reports an over range flag. FTYPE16, FTIMEH16, FTIMEM16, and FTIMEL16 contain a 16-bit signed value that can be read using variation 2 or 4. The FIMEx16 and FTYPE16 registers contain the FTIMEx or FTYPE value minus 65536 if the value is greater than 32767. The value is reported as a negative number without an over range flag.

Use *Table E.14* to determine the charger mode (CMODE).

Table E.14   Object 30, CMODE

CMODE Value	Description
0	Shutdown
1	Startup
2	Constant Current Charge
3	Fast Charge
4	Float Charge
5	Discharge
6	Bad Battery
7	Capacitor Charging
8	Battery Test

Event Data

DNP event data objects contain change-of-state and time-stamp information that the SEL-651R-2 collects and stores in a buffer. You can configure the SEL-651R-2 to either report the data without a polling request from the master (unsolicited data) or hold the data until the master requests the information with an event poll message.

With the event class settings ECLASSBn, ECLASSCn, and ECLASSAn, you can set the event class for binary, counter, and analog inputs for Ethernet port session n (the suffix n is not present for serial port event class settings). ECLASSV sets the event class for virtual terminal in serial sessions only. You can use the classes as a simple priority system for collecting event data. The relay does not treat data of different classes differently with respect to message scanning, but the relay does allow the master to perform independent class polls.

NOTE: Most RTUs that act as substation DNP masters perform an event poll that collects event data of all classes simultaneously. Confirm that the polling configuration of your master allows independent polling for each class before implementing separate classes in the SEL-651R-2.

For event data collection you must also consider and enter appropriate settings for dead band and scaling operation on analog points shown in *Table E.11*. You can either set and use default dead band and scaling according to data type or use a custom data map to select dead bands on a point-by-point basis. See *Configurable Data Mapping on page E.14* for a discussion of how to set scaling and dead band operation on a point-by-point basis.

Dead bands for analog inputs can be modified at run-time by writing to Object 34. Dead band changes via Object 34 are stored in volatile memory. Make sure to reissue the Object 34 dead band changes you want to retain after a change to DNP port settings, after issuing an **STA C** command, or after a relay power cycle.

The settings ANADBAn, ANADBVn, and ANADBMn control default dead band operation for the specified data type.

The relay uses the NUMcEVEn and AGEcEVEn settings to decide when to send unsolicited data to the master. The relay sends an unsolicited report when the total number of class c (where c is 1, 2, or 3) events accumulated in the event buffer for master n reaches NUMcEVEn (where n is 1–6). The relay also

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sends an unsolicited report if the age of the oldest class *c* event in the master *n* buffer exceeds AGE*c*EVE*n*. The SEL-651R-2 has the buffer capacities listed in *Table E.15*. If event limits are exceeded, then some event data will be lost.

Table E.15   SEL-651R-2 Event Data Buffer Limits

Event Data Type	Maximum Number of Events
Binary Inputs (object 2)	1024
Counter (object 22)	16
Analog Inputs (object 32)	200
Virtual Terminal (object 113)	5

Reading Relay Events

The SEL-651R-2 provides protective relay event history information in one of two modes: single-event or multiple-event mode. The port setting EVEMODE determines which mode each DNP session will start up in after a relay cold start, DNP port settings change, DNP map change or SER settings change. The default setting for EVEMODE is SINGLE. The reporting method can also be changed by asserting a binary output control point. The relay changes to multiple-event mode on a per-session basis if the NXTEVE control point is pulsed. The relay changes to single-event mode on a per-session basis if the SINGEVE control point is pulsed. Multiple-event mode supports first-in, first-out (FIFO) and last-in, first-out (LIFO) data access. A relay power cycle, a DNP port settings change, a DNP map change, or a SER settings change returns the reporting method to the mode specified by EVEMODE.

Port setting RPEVTYP determines the types of event reports reported in the DNP event summary data. When RPEVTYP := TRIP, only TRIP events are reported in the DNP event summary data. When RPEVTYP := ALL, all events are reported in the DNP event summary data. Single-Event mode provides the most recent RPEVTYP type event to the event summary area. In Single-Event mode, any new RPEVTYP type event causes event data to be latched into the event registers and made available in the DNP event summary data. The relay shall ignore any subsequent events for EVELOCK (port setting) time. The event registers will be cleared on a rising edge of the TRGTR Relay Word bit. The relay element EVELOCK is set when an event is triggered and reset when EVELOCK time expires.

Multiple-Event mode shall be initiated if the NXTEVE control point is pulsed or after a relay cold start, DNP port settings change, DNP map change, or SER settings change when EVEMODE := MULTI. In multiple-event mode, an event is loaded into the event registers when a control point is pulsed. The order that events are loaded depends on the binary output point controlled— Load-Event LIFO Mode or Load-Event FIFO Mode. The user cannot traverse event summaries forward, then backwards. When switching from multi-event mode to single-event mode by operating SINGEVE, the event registers are set to zero, but the event buffer is not reset. For example, if the relay is in single-event mode, three events occur, and the relay is switched to multiple-event mode by latching on NXTEVE, a read of the analog event registers will show data for the oldest event and FUNR will be equal to 2. If the relay is switched to single-event mode by operating SINGEVE, a read of the analog event registers will show that they are all zero but the event buffer will still contain two unread events. This can be seen by latching on NXTEVE to switch back to multiple-event mode. Once in multiple-event mode, a read of the analog event registers will show data for the oldest event and FUNR will be equal to 1, indicating that there is still one unread event in the event buffer. Note that

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the switching between modes is not normal behavior for a DNP master and is only discussed here to illustrate the event buffer functionality when switching modes.

To use Multiple-Event FIFO Mode, the master should monitor the UNRDEV binary input point (Unread Event Available, *Table E.11*), which will be asserted when there is an unread relay event summary. To read the oldest relay event summary, the master should latch on the NXTEVE binary output point (Load-Event FIFO Mode, see *Table E.8*). This will load the relay event summary analogs (fault type, location, current, frequency, settings group, shot country, and time, *Table E.11*) with information from the oldest relay event summary, discarding the values from the previous load.

After reading the analogs, the master should again check the UNRDEV binary input point, which will be asserted if another unread relay event summary is available. The master should continue to be asserted if another unread relay event summary is available. The master should continue this monitor-latch-on-read events process until the UNRDEV binary input point deasserts. If the master attempts to load values by latching on the NXTEVE binary output point with the UNRDEV binary input point deasserted, the relay event summary analogs will be filled with zeroes. With the FIFO method, the relay event summaries will always be collected in chronological order.

Similarly, to use Multiple-Event LIFO Mode, the master should also monitor the UNRDEV binary input point (Unread Event Available), which will be asserted when there is an unread relay summary. To read the newest relay event summary, the master should latch off the NXTEVE binary output point (Load-Event LIFO Mode, see *Table E.8*). This will load the relay event summary analogs with information from the newest relay event summary, discarding the values from the previous load. After reading the events, the master should check the UNRDEV binary input points and latch off the NXTEVE binary output point, if it is asserted, to read the next newest event. The master should continue this process until the UNRDEV binary input point deasserts. If the master attempts to load values by latching off the NXTEVE binary output point with the UNRDEV binary input point deasserted, the relay event summary analogs will be filled with zeroes. Note that events will be in chronological order if no new events have occurred, the most recent event will always be in the event registers if the load-event control point is latched after an event, and events will always be out of order if new events occur before all of the previous events have been read.

SELOGIC control equation RSTDNPE is used to clear the DNP event registers and the DNP event buffer for both single-event mode and multiple-event mode for all DNP sessions. When RSTDNPE is evaluated to one, the DNP event registers are set to zero and the DNP event buffer is cleared. The DNP binary output DRSTDNPE is similar in function to RSTDNPE, and can also be used to clear the DNP event registers and the DNP event buffer when the relay is in single-event mode or multiple-event mode on a per-session basis. Likewise, the SELOGIC control equation RSTTRGT can be used to clear the DNP event data in single-event mode.

Default Data Map

NOTE: Dead band changes via Object 34 are stored in volatile memory. Make sure to reissue the Object 34 dead bands after a warm (**HIS C**) or cold start (power cycle).

Table E.16 shows the SEL-651R-2 default data map. The default map is a subset of the reference map to reduce the response time. Use the custom DNP3 mapping functions to create the map required for your application.

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Table E.16   SEL-651R-2 DNP3 Default Data Map (Sheet 1 of 2)

DNP3 Setting	Object	Point Label	Index
BI_000	01,02	TRIPLED	006
BI_001	01,02	EN	007
BI_002–BI_025	01,02	TLED_01–TLED_24	008–031
BI_026	01,02	52A3P	148
BI_027	01,02	52AC	149
BI_028	01,02	52AB	150
BI_029	01,02	52AA	151
BI_030–BI_041	01,02	PB01_LED–PB12_LED	288–293, 296–301
BI_042	01,02	BTFAIL	305
BI_043	01,02	DISCHG	307
BI_044	01,02	CHRGG	308
BI_045	01,02	PWR_SRC1	311
BI_046	01,02	TCCAP	318
BI_047–BI_054	01,02	LT08–LT01	344–351
BI_055–BI_062	01,02	LT16–LT09	352–359
BI_063–BI_070	01,02	LT24–LT17	360–367
BI_071–BI_078	01,02	LT32–LT25	368–375
BI_079	01,02	SALARM	639
BI_080	01,02	HALARM	638
BI_081	01,02	RLYDIS	1616
BI_082	01,02	STFAIL	1617
BI_083	01,02	STWARN	1618
BI_084–BI_199	01,02	NA	
BO_000–BO_015	10,12	RB01–RB16	00–15
BO_016	10,12	DRST_DEM	36
BO_017	10,12	DRST_PDM	37
BO_018	10,12	DRST_ENE	38
BO_019	10,12	DRST_BK	39
BO_020	10,12	DRST_TAR	40
BO_021–070	10,12	NA	
AI_000	30,32,34	IA	00
AI_001	30,32,34	IB	02
AI_002	30,32,34	IC	04
AI_003	30,32,34	IN	06
AI_004	30,32,34	IG	34
AI_005	30,32,34	VAY	36
AI_006	30,32,34	VBY	38
AI_007	30,32,34	VCY	40
AI_008	30,32,34	VAZ	42
AI_009	30,32,34	VBZ	44
AI_010	30,32,34	VCZ	46

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Table E.16 SEL-651R-2 DNP3 Default Data Map (Sheet 2 of 2)

DNP3 Setting	Object	Point Label	Index
AI_011	30,32,34	MW3	87
AI_012	30,32,34	MVAR3	91
AI_013	30,32,34	PF3	95
AI_014	30,32,34	FREQ	104
AI_015	30,32,34	TEMP	105
AI_016	30,32,34	MWH3I	112
AI_017	30,32,34	MWH3O	113
AI_018	30,32,34	MVRH3I	120
AI_019	30,32,34	MVRH3O	121
AI_020	30,32,34	WEARA	166
AI_021	30,32,34	WEARB	167
AI_022	30,32,34	WEARC	168
AI_023–AI_199	30,32,34	NA	
AO_000	40,41	ACTGRP	00
AO_001–AI_007	40,41	NA	
CO_000	20,22	ACTGRP	00
CO_001	20,22	INTTA	01
CO_002	20,22	INTTB	02
CO_003	20,22	INTTC	03
CO_004	20,22	EXTTA	04
CO_005	20,22	EXTTB	05
CO_006	20,22	EXTTC	06
CO_007–CO_015	20,22	NA	

Appendix F

Relay Word Bits

Relay Word bits show the status of functions within the relay. The bits are available via communications protocols and the front panel.

Any Relay Word bit can be used in SELOGIC control equations (see *Section 7: SELOGIC Control Equation Programming*) and the Sequential Events Recorder (SER) trigger list settings (see *Section 12: Analyzing Events*).

Use *Table F.1* for an overview of what bits are available and their row number. You can display the bits with either the row number (**TAR** *row_number*) or the bit name (**TAR** *bit_name*).

Table F.2 provides an alphabetical listing of the Relay Word bits that includes a description of each bit.

Table F.1 and *Table F.2* include cross-reference information for most Relay Word bits. *Table F.3* describes Relay Word bits that are not described elsewhere in the manual.

Table F.1   Relay Word Bit Mapping (Sheet 1 of 6)

Row	Relay Word Bits[a]							
Enable and Target Bits (see Section 5 and Section 11)								
0	EN	TRIPLED	*	*	*	*	*	*
1	TLED_08	TLED_07	TLED_06	TLED_05	TLED_04	TLED_03	TLED_02	TLED_01
2	TLED_16	TLED_15	TLED_14	TLED_13	TLED_12	TLED_11	TLED_10	TLED_09
3	TLED_24	TLED_23	TLED_22	TLED_21	TLED_20	TLED_19	TLED_18	TLED_17
Instantaneous Overcurrent Elements (see Section 4)								
4	50A1	50B1	50C1	50P1	50A2	50B2	50C2	50P2
5	50A3	50B3	50C3	50P3	50A4	50B4	50C4	50P4
6	50G1	50G2	50G3	50G4	50Q1	50Q2	50Q3	50Q4
7	50N1	50N2	50N3	50N4	50A	50B	50C	50P32
8	50P5	50P6	50G5	50G6	50Q5	50Q6	50N5	50N6
9	50LA	50LB	50LC	50L	50GF	50GR	50QF	50QR
Inverse-Time and Definite-Time Overcurrent Elements (see Section 4)								
10	51AS	51AR	51A	51AT	51BS	51BR	51B	51BT
11	51CS	51CR	51C	51CT	51PS	51PR	51P	51PT
12	51G1S	51G1R	51G1	51G1T	51G2S	51G2R	51G2	51G2T
13	51QS	51QR	51Q	51QT	51N1S	51N1R	51N1	51N1T
14	50A1T	50B1T	50C1T	50P1T	50A2T	50B2T	50C2T	50P2T
15	50A3T	50B3T	50C3T	50P3T	50A4T	50B4T	50C4T	50P4T
16	50G1T	50G2T	50G3T	50G4T	50Q1T	50Q2T	50Q3T	50Q4T
17	50N1T	50N2T	50N3T	50N4T	51N2S	51N2R	51N2	51N2T

Table F.1 Relay Word Bit Mapping (Sheet 2 of 6)

Row	Relay Word Bits[a]							
Breaker Status, Loss-of-Potential, Ground Switch, Fault Identification, and Load Encroachment (see Section 4 and Section 5)								
18	52AA	52AB	52AC	52A3P	SPOA	SPOB	SPOC	SPO
19	V1GOOD	LOP	VPOLV	GNDSW	DD	SPE	SW1	3PO
20	FSA	FSB	FSC	*	PHASE_A	PHASE_B	PHASE_C	*
21	ZLOUT	ZLIN	ZLOAD	*	FAULT	*	*	*
Voltage Elements (see Section 4)								
22	27YA1	27YB1	27YC1	27YA2	27YB2	27YC2	59YA1	59YB1
23	59YC1	59YA2	59YB2	59YC2	27YAB1	27YBC1	27YCA1	59YAB1
24	59YBC1	59YCA1	59YN1	59YN2	59YQ1	59YV1	3P27Y	3P59Y
25	*	*	*	*	*	*	*	VSELY
26	27ZA1	27ZB1	27ZC1	27ZA2	27ZB2	27ZC2	59ZA1	59ZB1
27	59ZC1	59ZA2	59ZB2	59ZC2	27ZAB1	27ZBC1	27ZCA1	59ZAB1
28	59ZBC1	59ZCA1	59ZN1	59ZN2	59ZQ1	59ZV1	3P27Z	3P59Z
29	*	*	*	*	*	*	*	VSELZ
Synchronism-Check Elements (see Section 4)								
30	SF	25A1	25A2	SFAST	SSLOW	*	59VS	59VP
Frequency Elements (see Section 4) and FREQOK Relay Word bit (see Analog Scaling and Frequency Indicators on page F.19)								
31	81D1	81D2	81D3	81D4	81D5	81D6	FREQOK	*
32	81D1T	81D2T	81D3T	81D4T	81D5T	81D6T	27B81	*
Digital Inputs (see Section 7)								
33	*	IN107[b]	IN106[b]	IN105[b]	IN104[b]	IN103[b]	IN102[b]	IN101[b]
34	*	*	IN206	IN205	IN204	IN203	IN202	IN201
Rate-of-Change-of-Frequency Elements (see Section 4)								
35	*	*	*	81R4T	81R3T	81R2T	81R1T	81RT
Pushbutton LEDs (see Section 7 and Section 11)								
36	*	*	PB06_LED	PB05_LED	PB04_LED	PB03_LED	PB02_LED	PB01_LED
37	*	*	PB12_LED	PB11_LED	PB10_LED	PB09_LED	PB08_LED	PB07_LED
Power Supply, Battery Charger, and Recloser Interface (see Section 2, Section 7, and Section 8)								
38	PWR_SRC1	*	DISTST	CHRGG	DISCHG	DTFAIL	BTFAIL	TOSLP
39	*	TCCAP	XS_TRIP1	XS_TRIP2	XS_TRIP3	XS_CLOS1	XS_CLOS2	XS_CLOS3
Local and Breaker Operate Bits (see Section 5, Section 6, and Section 11)								
40	LB01	LB02	LB03	LB04	LB05	LB06	LB07	LB08
41	LB09	LB10	LB11	LB12	LB13	LB14	LB15	LB16
42	CCA	CCB	CCC	CC3	OCA	OCB	OCC	OC3
SOTF and Tripping Elements (see Section 5)								
43	SOTFE	SOTFT	TRGTR	*	TRIPA	TRIPB	TRIPC	TRIP3P

Table F.1   Relay Word Bit Mapping (Sheet 3 of 6)

Row	Relay Word Bits[a]							
Latch Bits (see Section 7)								
44	LT01	LT02	LT03	LT04	LT05	LT06	LT07	LT08
45	LT09	LT10	LT11	LT12	LT13	LT14	LT15	LT16
46	LT17	LT18	LT19	LT20	LT21	LT22	LT23	LT24
47	LT25	LT26	LT27	LT28	LT29	LT30	LT31	LT32
SELOGIC Variables/Timers (see Section 7)								
48	SV01	SV02	SV03	SV04	SV01T	SV02T	SV03T	SV04T
49	SV05	SV06	SV07	SV08	SV05T	SV06T	SV07T	SV08T
50	SV09	SV10	SV11	SV12	SV09T	SV10T	SV11T	SV12T
51	SV13	SV14	SV15	SV16	SV13T	SV14T	SV15T	SV16T
52	SV17	SV18	SV19	SV20	SV17T	SV18T	SV19T	SV20T
53	SV21	SV22	SV23	SV24	SV21T	SV22T	SV23T	SV24T
54	SV25	SV26	SV27	SV28	SV25T	SV26T	SV27T	SV28T
55	SV29	SV30	SV31	SV32	SV29T	SV30T	SV31T	SV32T
56	SV33	SV34	SV35	SV36	SV33T	SV34T	SV35T	SV36T
57	SV37	SV38	SV39	SV40	SV37T	SV38T	SV39T	SV40T
58	SV41	SV42	SV43	SV44	SV41T	SV42T	SV43T	SV44T
59	SV45	SV46	SV47	SV48	SV45T	SV46T	SV47T	SV48T
SELOGIC Counters (see Section 7)								
60	SC01QU	SC02QU	SC03QU	SC04QU	SC05QU	SC06QU	SC07QU	SC08QU
61	SC01QD	SC02QD	SC03QD	SC04QD	SC05QD	SC06QD	SC07QD	SC08QD
62	SC09QU	SC10QU	SC11QU	SC12QU	SC13QU	SC14QU	SC15QU	SC16QU
63	SC09QD	SC10QD	SC11QD	SC12QD	SC13QD	SC14QD	SC15QD	SC16QD
Reclosing Relays (see Section 6)								
64	79RS3P	79CY3P	79LO3P	SH03P	SH13P	SH23P	SH33P	SH43P
65	79RSA	79CYA	79LOA	SH0A	SH1A	SH2A	SH3A	SH4A
66	79RSB	79CYB	79LOB	SH0B	SH1B	SH2B	SH3B	SH4B
67	79RSC	79CYC	79LOC	SH0C	SH1C	SH2C	SH3C	SH4C
68	CLOSEA	CLOSEB	CLOSEC	CLOSE3P	CFA	CFB	CFC	CF3P
69	RCSFA	RCSFB	RCSFC	RCSF3P	OPTMNA	OPTMNB	OPTMNC	OPTMN3P
70	RSTMNA	RSTMNB	RSTMNC	RSTMN3P	ULCLA	ULCLB	ULCLC	ULCL3P
Directional Control (see Section 4)								
71	32QE	32QGE	32VE	*	F32Q	R32Q	F32QG	R32QG
72	F32V	R32V	F32P	R32P	*	*	*	*
73	32QF	32QR	32GF	32GR	32PF	32PR	*	*
Breaker Monitor, Demand Elements (see Section 8)								
74	BCWA	BCWB	BCWC	BCW	PDEM	NDEM	GDEM	QDEM
Digital Outputs (see Section 7)								
75	OUT108[b]	OUT107[b]	OUT106[b]	OUT105[b]	OUT104[b]	OUT103[b]	OUT102[b]	OUT101[b]
76	OUT202	OUT201	RCCL3X	RCTR3X	RCCL2X	RCTR2X	RCCL1X	RCTR1X

Table F.1 Relay Word Bit Mapping (Sheet 4 of 6)

Row	Relay Word Bits[a]							
77	*	*	*	*	*	*	*	*
Settings Group Bits								
78	SG1	SG2	SG3	SG4	SG5	SG6	SG7	SG8
Analog Scaling and IRIG-B Status (see Analog Scaling and Frequency Indicators on page F.19 and Appendix L)								
79	*	*	*	IRIGOK	INMET	ICMET	IBMET	IAMET
Mirrored Bits (see Appendix D)								
80	RMB8A	RMB7A	RMB6A	RMB5A	RMB4A	RMB3A	RMB2A	RMB1A
81	TMB8A	TMB7A	TMB6A	TMB5A	TMB4A	TMB3A	TMB2A	TMB1A
82	RMB8B	RMB7B	RMB6B	RMB5B	RMB4B	RMB3B	RMB2B	RMB1B
83	TMB8B	TMB7B	TMB6B	TMB5B	TMB4B	TMB3B	TMB2B	TMB1B
84	LBOKA	CBADA	RBADA	ROKA	LBOKB	CBADB	RBADB	ROKB
Voltage Sag/Swell/Interruption Elements and TESTDB Indication (see Section 4 and Section 10)								
85	SAGA	SAGB	SAGC	SAG3P	SWA	SWB	SWC	SW3P
86	*	*	*	*	*	*	*	*
87	INTA	INTB	INTC	INT3P	*	*	*	TESTDB
Power Elements (see Section 4)								
88	*	*	*	3PWR1	*	*	*	3PWR2
89	*	*	*	3PWR3	*	*	*	3PWR4
Operator Controls (see Section 11)								
90	*	*	PB06	PB05	PB04	PB03	PB02	PB01
91	*	*	PB06_PUL	PB05_PUL	PB04_PUL	PB03_PUL	PB02_PUL	PB01_PUL
92	*	*	PB12	PB11	PB10	PB09	PB08	PB07
93	*	*	PB12_PUL	PB11_PUL	PB10_PUL	PB09_PUL	PB08_PUL	PB07_PUL
Remote Bits (see Section 10 and Appendix C)								
94	RB01	RB02	RB03	RB04	RB05	RB06	RB07	RB08
95	RB09	RB10	RB11	RB12	RB13	RB14	RB15	RB16
96	RB17	RB18	RB19	RB20	RB21	RB22	RB23	RB24
97	RB25	RB26	RB27	RB28	RB29	RB30	RB31	RB32
Target Reset Control (see Section 5 and Appendix E), Metering Reset Control (see Section 8), and Alarm Reset Control (see Section 9 and Section 13)								
98	RSTTRGT	RST_MML	RST_ENE	RST_HIS	RST_BK	RST_PDM	RST_DEM	RST_HAL
Ethernet Status (see Section 10)								
99	LINK5[c]	LINK5A[d]	LINK5B[d]	LNKFAIL	P5ASEL[d]	P5BSEL[d]	TSNTPP	TSNTPB
SELogic Variables/Timers (see Section 7)								
100	SV49	SV50	SV51	SV52	SV49T	SV50T	SV51T	SV52T
101	SV53	SV54	SV55	SV56	SV53T	SV54T	SV55T	SV56T
102	SV57	SV58	SV59	SV60	SV57T	SV58T	SV59T	SV60T
103	SV61	SV62	SV63	SV64	SV61T	SV62T	SV63T	SV64T

Table F.1   Relay Word Bit Mapping (Sheet 5 of 6)

Row	Relay Word Bits[a]							
IRIG Time Quality Information, Phasor Measurement Status and Trigger Status (see Appendix J)								
104	DST	DSTP	LPSEC	LPSECP	TQUAL4	TQUAL3	TQUAL2	TQUAL1
105	TSOK	TIRIG	PMDOK	PMTRIG	TREA4	TREA3	TREA2	TREA1
Diagnostic and Alarm Bits (see Section 9, Section 10, and Section 13)								
106	SALARM	ACCESS	*	*	HALARMA	HALARMP	HALARML	HALARM
107	*	*	PASNVAL	ACCESSP	GRPSW	SETCHG	CHGPASS	BADPASS
Virtual Bits (see Appendix L)								
108[e]	VB001	VB002	VB003	VB004	VB005	VB006	VB007	VB008
109[e]	VB009	VB010	VB011	VB012	VB013	VB014	VB015	VB016
110[e]	VB017	VB018	VB019	VB020	VB021	VB022	VB023	VB024
111[e]	VB025	VB026	VB027	VB028	VB029	VB030	VB031	VB032
112[e]	VB033	VB034	VB035	VB036	VB037	VB038	VB039	VB040
113[e]	VB041	VB042	VB043	VB044	VB045	VB046	VB047	VB048
114[e]	VB049	VB050	VB051	VB052	VB053	VB054	VB055	VB056
115[e]	VB057	VB058	VB059	VB060	VB061	VB062	VB063	VB064
116[e]	VB065	VB066	VB067	VB068	VB069	VB070	VB071	VB072
117[e]	VB073	VB074	VB075	VB076	VB077	VB078	VB079	VB080
118[e]	VB081	VB082	VB083	VB084	VB085	VB086	VB087	VB088
119[e]	VB089	VB090	VB091	VB092	VB093	VB094	VB095	VB096
120[e]	VB097	VB098	VB099	VB100	VB101	VB102	VB103	VB104
121[e]	VB105	VB106	VB107	VB108	VB109	VB110	VB111	VB112
122[e]	VB113	VB114	VB115	VB116	VB117	VB118	VB119	VB120
123[e]	VB121	VB122	VB123	VB124	VB125	VB126	VB127	VB128
High-Impedance Fault Detection and 50G High-Impedance (HIZ) Fault Detection[f] (see Section 4)								
124	*	*	*	*	*	*	HIFMODE[g]	HIFREC
125	*	*	*	*	HIF2_A	HIF2_B	HIF2_C	3PH_EVE
126	HIA2_A	HIA2_B	HIA2_C	FRZCLRA	FRZCLRB	FRZCLRC	HIFER[g]	HIFFRZ[g]
127	DIA_DIS	DIB_DIS	DIC_DIS	DVA_DIS	DVB_DIS	DVC_DIS	*	OREDHIF2
128	DL2CLRA	DL2CLRB	DL2CLRC	ITUNE_A	ITUNE_B	ITUNE_C	INI_HIF	HIFITUNE[g]
129	NTUNE_A	NTUNE_B	NTUNE_C	DUPA	DUPB	DUPC	CPUDO0	CHIZ0
130	DDNA	DDNB	DDNC	LRA	LRB	LRC	LR3	50GHIZ
131	HIZ170	HIZ171	HIZ172	HIZ173	HIZ174	HIZ175	HIZ180	HIZ181
132	HIZ190	HIZ191	HIZ192	50GHIZA	HIZRST[g]	*	*	*
Second-Harmonic Blocking (see Section 4)								
133	HBL2AT	HBL2BT	HBL2CT	HBL2T	*	*	*	*

Table F.1 Relay Word Bit Mapping (Sheet 6 of 6)

Row	Relay Word Bits[a]							
Multi-Recloser Interface[h] (see Section 2)								
134	A1_CFG	A2_CFG	A3_CFG	*	*	*	*	69_YH
DNP Event Register/Buffer Reset Equation (see Appendix E)								
135	*	*	*	*	*	*	*	RSTDNPE

a An asterisk (*) denotes "reserved for future use."
b IN101–IN107 and OUT101–OUT108 are displayed only if the extra I/O is ordered.
c LINK5 is replaced by "*" when dual Ethernet connectors are present.
d Relay Word bits (for dual Ethernet ports) are replaced by "*" when a single Ethernet connector is present.
e Virtual bits VB001–VB128 are only present in relays ordered with IEC 61850 protocol.
f Relay Word bits for row 124–132 are only present in relays ordered with High-Impedance Fault Detection.
g Relay Word bits follows SELᴏɢɪᴄ Setting of same name.
h Relay Word bits are only present in relays ordered with Multi-Recloser Interface.

Table F.2 Alphabetic List of Relay Word Bits (Sheet 1 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
25A1, 25A2	Synchronism-check elements (see *Figure 4.31*)	Control	30
27B81	Undervoltage element for frequency element blocking (see *Figure 4.34* and *Figure 4.35*)	Control	32
27YA1, 27YA2	A-phase undervoltage elements, Y-terminal (see *Figure 4.26*)	Control	22
27YAB1	AB-phase-to-phase undervoltage element, Y-terminal (see *Figure 4.27*)	Control	23
27YB1, 27YB2	B-phase undervoltage elements, Y-terminal (see *Figure 4.26*)	Control	22
27YBC1	BC-phase-to-phase undervoltage element, Y-terminal (see *Figure 4.27*)	Control	23
27YC1, 27YC2	C-phase undervoltage elements, Y-terminal (see *Figure 4.26*)	Control	22
27YCA1	CA-phase-to-phase undervoltage, Y-terminal (see *Figure 4.27*)	Control	23
27ZA1, 27ZA2	A-phase undervoltage elements, Z-terminal (see *Figure 4.28*)	Control	26
27ZAB1	AB-phase-to-phase undervoltage element, Z-terminal (see *Figure 4.29*)	Control	27
27ZB1, 27ZB2	B-phase undervoltage elements, Z-terminal (see *Figure 4.28*)	Control	26
27ZBC1	BC-phase-to-phase undervoltage element, Z-terminal (see *Figure 4.29*)	Control	27
27ZC1, 27ZC2	C-phase undervoltage elements, Z-terminal (see *Figure 4.28*)	Control	26
27ZCA1	CA-phase-to-phase undervoltage element, Z-terminal (see *Figure 4.29*)	Control	27
32GF	Forward directional control for ground overcurrent elements (see *Figure 4.57*)	Testing, Special directional control schemes	73
32GR	Reverse directional control for ground overcurrent elements (see *Figure 4.57*)	Testing, Special directional control schemes	73
32PF	Forward directional control for phase overcurrent elements (see *Figure 4.61*)	Testing, Special directional control schemes	73
32PR	Reverse directional control for phase overcurrent elements (see *Figure 4.61*)	Testing, Special directional control schemes	73
32QE	Enable for negative-sequence voltage-polarized directional element (see *Figure 4.52*)	Testing	71
32QF	Forward directional control for negative-sequence overcurrent elements (see *Figure 4.61*)	Testing, Special directional control schemes	73

Table F.2   Alphabetic List of Relay Word Bits (Sheet 2 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
32QGE	Enable for negative-sequence voltage-polarized directional element for ground (see *Figure 4.52*)	Testing	71
32QR	Reverse directional control for negative-sequence overcurrent elements (see *Figure 4.61*)	Testing, Special directional control schemes	73
32VE	Enable for zero-sequence voltage-polarized directional element (see *Figure 4.53*)	Testing	71
3P27Y	Three-phase undervoltage element, Y-terminal = 27YA1 AND 27YB1 AND 27YC1 (see *Figure 4.26*)	Control	24
3P27Z	Three-phase undervoltage element, Z-terminal = 27ZA1 AND 27ZB1 AND 27ZC1 (see *Figure 4.28*)	Control	28
3P59Y	Three-phase overvoltage element, Y-terminal = 59YA1 AND 59YB1 AND 59YC1 (see *Figure 4.26*)	Control	24
3PH_EVE	Three-phase Event Detection in the Difference Current Quantity (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	125
3P59Z	Three-phase overvoltage element, Z-terminal = 59ZA1 AND 59ZB1 AND 59ZC1 (see *Figure 4.28*)	Control	28
3PO	Three-pole open condition (see *Figure 5.5*)	Testing	19
3PWR1–3PWR4	Three-phase power elements, 1–4 (see *Figure 4.44*)	Tripping, Control	88, 89
50A	A-phase instantaneous overcurrent element = 50A1 OR 50A2 OR 50A3 OR 50A4 (see *Figure 4.7*)	Tripping, Control	7
50A1–50A4	Level 1–Level 4 A-phase instantaneous overcurrent elements (see *Figure 4.1*)	Tripping, Control	4, 5
50A1T–50A4T	Level 1–Level 4 A-phase definite time-overcurrent elements (see *Figure 4.4*)	Tripping, Control	14, 15
50B	B-phase instantaneous overcurrent element = 50B1 OR 50B2 OR 50B3 OR 50B4 (see *Figure 4.7*)	Tripping, Control	7
50B1–50B4	Level 1–Level 4 B-phase instantaneous overcurrent elements (see *Figure 4.1*)	Tripping, Control	4, 5
50B1T–50B4T	Level 1–Level 4 B-phase definite time-overcurrent elements (see *Figure 4.5*)	Tripping, Control	14, 15
50C	C-phase instantaneous overcurrent element = 50C1 OR 50C2 OR 50C3 OR 50C4 (see *Figure 4.7*)	Tripping, Control	7
50C1–50C4	Level 1–Level 4 C-phase instantaneous overcurrent elements (see *Figure 4.1*)	Tripping, Control	4, 5
50C1T–50C4T	Level 1–Level 4 C-phase definite time-overcurrent elements (see *Figure 4.6*)	Tripping, Control	14, 15
50G1–50G6	Level 1–Level 6 ground instantaneous overcurrent elements (see *Figure 4.12* and *Figure 4.13*)	Tripping, Testing, Control	6, 8
50G1T–50G4T	Level 1–Level 4 ground definite time-overcurrent elements (see *Figure 4.12*)	Tripping, Testing, Control	16
50GF	Forward direction ground overcurrent threshold exceeded (see *Figure 4.53*)	Testing	9
50GHIZ	Ground HIZ Instantaneous Overcurrent Pickup (see *Figure 4.77*)	Testing, Control	130
50GHIZA	50G HIZ Alarm (see *Figure 4.80*)	Indication, Control	132
50GR	Reverse direction ground overcurrent threshold exceeded (see *Figure 4.53*)	Testing	9

Table F.2   Alphabetic List of Relay Word Bits (Sheet 3 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
50L	Phase instantaneous overcurrent element for load detection = 50LA OR 50LB OR 50LC (see *Figure 5.5*)	Testing	9
50LA	A-phase instantaneous overcurrent element for load detection (see *Figure 5.6*)	Testing	9
50LB	B-phase instantaneous overcurrent element for load detection (see *Figure 5.6*)	Testing	9
50LC	C-phase instantaneous overcurrent element for load detection (see *Figure 5.6*)	Testing	9
50N1–50N6	Level 1–Level 6 neutral instantaneous overcurrent elements (see *Figure 4.10*)	Tripping, Testing, Control	7, 8
50N1T–50N4T	Level 1–Level 4 neutral definite time-overcurrent elements (see *Figure 4.10*)	Tripping, Testing, Control	17
50P1–50P6	Level 1–Level 6 phase instantaneous overcurrent elements (see *Figure 4.1* and *Figure 4.2*)	Tripping, Testing, Control	4, 5, 8
50P1T–50P4T	Level 1–Level 4 phase definite time-overcurrent elements (see *Figure 4.3*)	Tripping, Testing, Control	14, 15
50P32	Three-phase overcurrent threshold exceeded for phase directional element (see *Figure 4.60*)	Testing	7
50Q1–50Q6	Level 1–Level 6 negative-sequence instantaneous overcurrent elements (see *Figure 4.14* and *Figure 4.15*)	Testing, Control	6, 8
50Q1T–50Q4T	Level 1–Level 4 negative-sequence definite time-overcurrent elements (see *Figure 4.14*)	Testing, Control	16
50QF	Forward direction negative-sequence overcurrent threshold exceeded (see *Figure 4.52*)	Testing	9
50QR	Reverse direction negative-sequence overcurrent threshold exceeded (see *Figure 4.52*)	Testing	9
51A	A-phase time-overcurrent element picked up (see *Figure 4.17*)	Testing, Control	10
51AR	A-phase time-overcurrent element reset (see *Figure 4.17*)	Testing	10
51AS	A-phase time-overcurrent element, J/K setting indication[b] (see *Figure 4.17*)	Control	10
51AT	A-phase time-overcurrent element timed out (see *Figure 4.17*)	Tripping	10
51B	B-phase time-overcurrent element picked up (see *Figure 4.18*)	Testing, Control	10
51BR	B-phase time-overcurrent element reset (see *Figure 4.18*)	Testing	10
51BS	B-phase time-overcurrent element, J/K setting indication[b] (see *Figure 4.18*)	Control	10
51BT	B-phase time-overcurrent element timed out (see *Figure 4.18*)	Tripping	10
51C	C-phase time-overcurrent element picked up (see *Figure 4.19*)	Testing, Control	11
51CR	C-phase time-overcurrent element reset (see *Figure 4.19*)	Testing	11
51CS	C-phase time-overcurrent element, J/K setting indication[b] (see *Figure 4.19*)	Control	11
51CT	C-phase time-overcurrent element timed out (see *Figure 4.19*)	Tripping	11
51G1	#1 Ground time-overcurrent element picked up (see *Figure 4.22*)	Testing, Control	12
51G1R	#1 Ground time-overcurrent element reset (see *Figure 4.22*)	Testing	12
51G1S	#1 Ground time-overcurrent element, J/K setting indication[b] (see *Figure 4.22*)	Control	12
51G1T	#1 Ground time-overcurrent element timed out (see *Figure 4.22*)	Tripping	12

Table F.2   Alphabetic List of Relay Word Bits (Sheet 4 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
51G2	#2 Ground time-overcurrent element picked up (see *Figure 4.23*)	Testing, Control	12
51G2R	#2 Ground time-overcurrent element reset (see *Figure 4.23*)	Testing	12
51G2S	#2 Ground time-overcurrent element, J/K setting indication[b] (see *Figure 4.23*)	Control	12
51G2T	#2 Ground time-overcurrent element timed out (see *Figure 4.23*)	Tripping	12
51N1	#1 Neutral time-overcurrent element picked up (see *Figure 4.20*)	Testing, Control	13
51N1R	#1 Neutral time-overcurrent element reset (see *Figure 4.20*)	Testing	13
51N1S	#1 Neutral time-overcurrent element, J/K setting indication[b] (see *Figure 4.20*)	Control	13
51N1T	#1 Neutral time-overcurrent element timed out (see *Figure 4.20*)	Tripping	13
51N2	#2 Neutral time-overcurrent element picked up (see *Figure 4.21*)	Testing, Control	17
51N2R	#2 Neutral time-overcurrent element reset (see *Figure 4.21*)	Testing	17
51N2S	#2 Neutral time-overcurrent element, J/K setting indication[b] (see *Figure 4.21*)	Control	17
51N2T	#2 Neutral time-overcurrent element timed out (see *Figure 4.21*)	Tripping	17
51P	Maximum-phase time-overcurrent element picked up (see *Figure 4.16*)	Testing, Control	11
51PR	Maximum-phase time-overcurrent element reset (see *Figure 4.16*)	Testing	11
51PS	Maximum-phase time-overcurrent element, J/K setting indication[b] (see *Figure 4.16*)	Control	11
51PT	Maximum-phase time-overcurrent element timed out (see *Figure 4.16*)	Tripping	11
51Q	Negative-sequence time-overcurrent element picked up (see *Figure 4.24*)	Testing, Control	13
51QR	Negative-sequence time-overcurrent element reset (see *Figure 4.24*)	Testing	13
51QS	Negative-sequence time-overcurrent element, J/K setting indication[b] (see *Figure 4.24*)	Control	13
51QT	Negative-sequence time-overcurrent element timed out (see *Figure 4.24*)	Tripping	13
52A3P	Circuit breaker status (see *Figure 6.2*)	Indication	18
52AA, 52AB, 52AC	A-, B-, or C-phase circuit breaker status (available when setting BKTYP := 1) (see *Figure 6.2*)	Indication	18
59VP	Healthy voltage VP for synchronism check (see *Figure 4.30*)	Testing	30
59VS	Healthy voltage VS for synchronism check (see *Figure 4.30*)	Testing	30
59YA1, 59YA2	A-phase overvoltage elements, Y-terminal (see *Figure 4.26*)	Control	22, 23
59YAB1	AB-phase-to-phase overvoltage element, Y-terminal (see *Figure 4.27*)	Control	23
59YB1, 59YB2	B-phase overvoltage elements, Y-terminal (see *Figure 4.26*)	Control	22, 23
59YBC1	BC-phase-to-phase overvoltage element, Y-terminal (see *Figure 4.27*)	Control	24
59YC1, 59YC2	C-phase overvoltage elements, Y-terminal (see *Figure 4.26*)	Control	23
59YCA1	CA-phase-to-phase overvoltage element, Y-terminal (see *Figure 4.27*)	Control	24
59YN1, 59YN2	Zero-sequence overvoltage elements, Y-terminal (see *Figure 4.27*)	Control	24
59YQ1	Negative-sequence overvoltage element, Y-terminal (see *Figure 4.27*)	Control	24
59YV1	Positive-sequence overvoltage element, Y-terminal (see *Figure 4.27*)	Control	24
59ZA1, 59ZA2	A-phase overvoltage elements, Z-terminal (see *Figure 4.28*)	Control	26, 27

Table F.2 Alphabetic List of Relay Word Bits (Sheet 5 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
59ZAB1	AB-phase-to-phase overvoltage element, Z-terminal (see *Figure 4.29*)	Control	27
59ZB1, 59ZB2	B-phase overvoltage elements, Z-terminal (see *Figure 4.28*)	Control	26, 27
59ZBC1	BC-phase-to-phase overvoltage element, Z-terminal (see *Figure 4.29*)	Control	28
59ZC1, 59ZC2	C-phase overvoltage elements, Z-terminal (see *Figure 4.28*)	Control	27
59ZCA1	CA-phase-to-phase overvoltage element, Z-terminal (see *Figure 4.29*)	Control	28
59ZN1, 59ZN2	Zero-sequence overvoltage elements, Z-terminal (see *Figure 4.29*)	Control	28
59ZQ1	Negative-sequence overvoltage element, Z-terminal (see *Figure 4.29*)	Control	28
59ZV1	Positive-sequence overvoltage elements, Z-terminal (see *Figure 4.29*)	Control	28
69__YH	Yellow operating handle in lock-open position (Multi-Recloser Interface only; see *Figure 5.2* and *Figure 6.11*)	Tripping, Control	134
79CY3P	Reclosing relay in the Reclose Cycle State (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
79CYA, 79CYB, 79CYC	A-, B-, or C-phase reclosing relay in the Reclose Cycle State (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
79LO3P	Reclosing relay in the Lockout State (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
79LOA, 79LOB, 79LOC	A-, B-, or C-phase reclosing relay in the Lockout State (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
79RS3P	Reclosing relay in the Reset State (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
79RSA, 79RSB, 79RSC	A-, B-, or C-phase reclosing relay in the Reset State (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
81D1–81D6	Level 1–Level 6 instantaneous frequency elements (for testing only) (see *Figure 4.38*)	Testing	31
81D1T–81D6T	Level 1–Level 6 definite-time frequency elements (see *Figure 4.38*)	Tripping, Control	32
81R1T–81R4T	Level 1–Level 4 rate-of-change-of-frequency elements (see *Figure 4.39*	Tripping, Control	35
81RT	81R1T OR 81R2T OR 81R3T OR 81R4T	Tripping, Control	35
A1_CFG	Global setting RECL_CFG := A1 (Multi-Recloser Interface only; see *Table 2.4*, *Figure 5.2*, and *Figure 6.11*)	Indication, Control	134
A2_CFG	Global setting RECL_CFG := A2 (Multi-Recloser Interface only; see *Table 2.4*, *Figure 5.2*, and *Figure 6.11*)	Indication, Control	134
A3_CFG	Global Setting RECL_CFG := A3 (Multi-Recloser Interface only; see *Table 2.4*, *Figure 5.2*, and *Figure 6.11*.	Indication, Control	134
ACCESS	Asserted while any user is logged in at Access Level B or higher (see *Port Access Levels on page 10.21*)	Indication	106
ACCESSP	Pulses for approximately 1 second when any user increases their access level to B or higher (see *Port Access Levels on page 10.21*)	Indication	107
BADPASS	Pulses for approximately 1 second whenever a user enters three successive bad passwords (see *Port Access Levels on page 10.21*)	Indication	107
BCW	Any contact wear has reached 100% wear level = BCWA OR BCWB OR BCWC (see *Breaker/Recloser Contact Wear Monitor on page 8.23*)	Indication	74
BCWA	A-phase breaker contact wear has reached 100% wear level (see *Breaker/Recloser Contact Wear Monitor on page 8.23*)	Indication	74

Table F.2 Alphabetic List of Relay Word Bits (Sheet 6 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
BCWB	B-phase breaker contact wear has reached 100% wear level (see *Breaker/Recloser Contact Wear Monitor on page 8.23*)	Indication	74
BCWC	C-phase breaker contact wear has reached 100% wear level (see *Breaker/Recloser Contact Wear Monitor on page 8.23*)	Indication	74
BTFAIL	Battery failure (see *Battery Status on page 8.43*)	Indication, Control	38
CBADA, CBADB	MIRRORED BITS channel unavailability over threshold, Channels A and B (see *Appendix D: MIRRORED BITS Communications*)	Indication	84
CC3	Asserts for one processing interval for CLOSE command execution (see *Figure 6.4*)	Testing, Control	42
CCA	Asserts for one processing interval for CLOSE A command execution	Testing, Control	42
CCB	Asserts for one processing interval for CLOSE B command execution	Testing, Control	42
CCC	Asserts for one processing interval for CLOSE C command execution	Testing, Control	42
CF3P	Close Failure condition (available when setting ESPB := N) (see *Figure 6.1*)	Indication	68
CFA, CFB, CFC	A-, B-, or C-phase Close Failure condition (available when setting ESPB := Y) (see *Figure 6.1*)	Indication	68
CHGPASS	Pulses for approximately one second whenever a password changes. (see *Port Access Levels on page 10.21*)	Indication	107
CHIZ0	HIZ Counts = 0 (see *50G High-Impedance (HIZ) Fault Detection on page 4.116*)	Control	129
CHRGG	Battery is charging (see *Battery Status on page 8.43*)	Indication	38
CLOSE3P	Close logic output asserted (available when setting ESPB := N) (see *Close Logic on page 6.5*)	Testing, Control	68
CLOSEA, CLOSEB, CLOSEC	A-, B-, or C-phase close logic output asserted (available when setting ESPB := Y) (see *Close Logic on page 6.5*)	Testing, Control	68
CPUDO0	50G HIZ Pickup/Dropout counts = 0 (see *50G High-Impedance (HIZ) Fault Detection on page 4.116*)	Control	129
DD	Disturbance Detector (see *Switch-Onto-Fault (SOTF) Trip Logic on page 5.11*)	Indication	19
DDNA, DDNB, DDNC	A-, B-, C-Phase Tuning Threshold Decrease (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	130
DIA_DIS, DIB_DIS, DIC_DIS	A-, B-, C-Phase Large Difference Current Disturbance (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	127
DISCHG	Battery is discharging (see *Battery Status on page 8.43*)	Indication	38
DISTST	Battery Discharge Test in Progress (see *Battery System Operation on page 8.40*)	Testing, Indication	38
DL2CLRA, DL2CLRB, DL2CLRC	A-, B-, C- Phase Decision Logic 2 Clear (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	128
DST	Daylight Saving Time active	Indication	104
DSTP	Daylight Saving Time change Pending. Asserts up to a minute before daylight saving time change.	Indication	104
DTFAIL	Battery failed discharge test (see *Automatic Battery Load Test on page 8.42*).	Indication	38
DUPA, DUPB, DUPC	A-, B-, C- Phase Tuning Threshold Increase (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	129

Table F.2   Alphabetic List of Relay Word Bits (Sheet 7 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
DVA_DIS, DVB_DIS, DVC_DIS	A-, B-, C- Phase Difference Voltage Disturbance (see *High-Imped-ance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	127
EN	Enabled LED. Asserts when relay enabled. (see *Front-Panel Target LEDs ENABLED and TRIP on page 5.15*)	Indication	0
F32P	Forward positive-sequence voltage-polarized directional element (see *Figure 4.60*)	Testing, Special direc-tional control schemes	72
F32Q	Forward negative-sequence voltage-polarized directional element (see *Figure 4.59*)	Testing, Special direc-tional control schemes	71
F32QG	Forward negative-sequence voltage-polarized directional element (for ground) (see *Figure 4.55*)	Testing, Special direc-tional control schemes	71
F32V	Forward zero-sequence voltage-polarized directional element (see *Figure 4.56*)	Testing, Special direc-tional control schemes	72
FAULT	Output of SELOGIC control equation FAULT (see *SELOGIC Control Equation Setting FAULT on page 5.18*)	Indication	21
FREQOK	System frequency and tracking frequency valid (see *Analog Scaling and Frequency Indicators on page F.19*)	Indication, Testing	31
FRZCLRA, FRZ-CLRB, FRZCLRC	A-, B-, C- Phase Averager Freeze and Trending Clear Condition (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Testing, Control	126
FSA, FSB, FSC	Fault identification logic outputs (used in targeting)	Control	19
GDEM	Ground demand current element (see *Figure 8.4*)	Indication	74
GNDSW	Ground Switch (Ground elements operating off of channel IN when asserted) (see *Table 4.23*)	Testing	19
GRPSW	Pulses for approximately 1 second whenever groups are switched (see *Section 9: Settings*)	Indication	107
HALARM	Hardware Alarm (diagnostic alarms) (see *Section 13: Testing and Troubleshooting*)	Indication	106
HALARMA	This bit pulses for approximately five seconds per minute when a hardware diagnostic warning occurs. It stops pulsing within approxi-mately one second of the rising edge of RST_HAL (see *Section 13: Testing and Troubleshooting*).	Indication	106
HALARML	Latches in for relay diagnostic failures (see *Section 13: Testing and Troubleshooting*)	Indication	106
HALARMP	Pulses for approximately five seconds when a warning diagnostic con-dition occurs (see *Section 13: Testing and Troubleshooting*)	Indication	106
HBL2AT, HBL2BT, HBL2CT	A-, B-, C- Phase Second-Harmonic Block Timed Out (see *Figure 4.25*)	Testing, Control	133
HBL2T	Combined-Phase Second-Harmonic Block Timed Out (see *Figure 4.25*)	Testing, Control	133
HIA2_A, HIA2_B, HIA2_C	A-, B-, C- Phase HIF Alarm from Algorithm 2 (see *Figure 4.75*)	Indication	126
HIF2_A, HIF2_B, HIF2_C	A-, B-, C- Phase HIF Detection by Algorithm 2 (see *Figure 4.75*)	Indication, Tripping, Con-trol	125
HIFER	HIF Event Report Setting (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	HIF Event Report duration	126
HIFFRZ	SELOGIC Control to Freeze HIF Detection (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Testing, Control	126

Table F.2   Alphabetic List of Relay Word Bits (Sheet 8 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
HIFITUNE	SELOGIC Control to Initiate Tuning Process for HIF (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Testing, Control	128
HIFMODE	Sensitivity Mode of HIF Algorithms (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Testing, Control	124
HIFREC	HIF Event Report being Captured by Device (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	124
HIZ170–HIZ175	States 170 to 175 of HIZ Logic (see *50G High-Impedance (HIZ) Fault Detection on page 4.116*)	Status of HIZ logic states	131
HIZ180–HIZ181	States 180 to 181 of HIZ Logic (see *50G High-Impedance (HIZ) Fault Detection on page 4.116*)	Status of HIZ logic states	131
HIZ190–HIZ192	States 191 to 192 of HIZ Logic (see *50G High-Impedance (HIZ) Fault Detection on page 4.116*)	Status of HIZ logic states	132
HIZRST	Reset 50G HIZ Alarm (see *50G High-Impedance (HIZ) Fault Detection on page 4.116*)	Testing, Control	132
IAMET, IBMET, ICMET	Channel IA, IB, or IC operating from high-gain channel (see *Analog Scaling and Frequency Indicators on page F.19*)	Event Report	79
IN101–IN107	Optoisolated inputs IN101–IN107, asserted (optional inputs) (see *Figure 7.18*)	Status sensing or control via optoisolated inputs (only operable if optional I/O installed)	33
IN201–IN206	Status inputs IN201–IN206, asserted (see *Figure 7.17*)	Status sensing or control via optoisolated inputs	34
INI_HIF	Initiate Tuning Process for HIF (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Testing, Control	128
INMET	Channel IN operating from high-gain channel (see *Analog Scaling and Frequency Indicators on page F.19*)	Event Report	79
INT3P	Three-phase voltage interruption element = INTA AND INTB AND INTC (see *Voltage Interruption Elements on page 4.60*)	Sag/Swell/Int reporting	87
INTA, INTB, INTC	A-, B-, or C-phase voltage interruption elements (see *Voltage Interruption Elements on page 4.60*)	Sag/Swell/Int reporting	87
IRIGOK	IRIG time-source signal detected (= TIRIG OR TSOK) (see *Configuring High-Accuracy Timekeeping on page J.21*)	Indication	79
ITUNE_A, ITUNE_B, ITUNE_C	A-, B-, C- Phase Initial Tuning (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	128
LB01–LB16	Local bits 01–16, asserted (see *Control Menu on page 11.7*)	Control via front panel—replacing traditional panel-mounted control switches	40, 41
LBOKA, LBOKB	MIRRORED BITS channel looped back OK, Channels A and B (see *Table 12.4* and *Appendix D: MIRRORED BITS Communications*)	Indication	84
LINK5	Asserted when a valid Ethernet link is detected on port 5 (see *Section 10: Communications*) (only on relays with a single Ethernet connector)	Indication, Testing	99
LINK5A, LINK5B	Asserted when a valid Ethernet link is detected on port 5A or 5B (see *Section 10: Communications*) (only on relays with dual Ethernet connectors)	Indication, Testing	99
LNKFAIL	Asserted when a valid link is not detected on the active port(s) (see *Section 10: Communications*)	Indication, Testing	99

Table F.2   Alphabetic List of Relay Word Bits (Sheet 9 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
LOP	Loss-of-potential (see *Loss-of-Potential Logic on page 4.77*)	Testing, Special directional control schemes	19
LPSEC	Leap Second direction. Add second if deasserted, delete if asserted. Only available when Global setting IRIGC = C37.118 and a proper IRIG signal is decoded (see *Configuring High-Accuracy Timekeeping on page J.21*).	Indication	104
LPSECP	Leap Second Pending. Asserts up to a minute prior to leap second insertion (see *Configuring High-Accuracy Timekeeping on page J.21*).	Indication	104
LR3	Three-phase Load Reduction Event (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Indication, Control	130
LRA, LRB, LRC	A-, B-, C- Phase Load Reduction (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Indication	130
LT01–LT32	Latch bits 01–32, asserted (see *Latch Bits on page 7.9*)	Control—replacing traditional latching relays	44–47
NDEM	Neutral demand current element (available when EGNDSW := N) (see *Figure 8.4*)	Indication	74
NTUNE_A, NTUNE_B, NTUNE_C	A-, B-, C- Phase Normal Tuning (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Control	129
OC3	Asserts for one processing interval for **OPEN** command execution (see *Figure 5.2*)	Testing, Control	42
OCA	Asserts for one processing interval for **OPEN A** command execution	Testing, Control	42
OCB	Asserts for one processing interval for **OPEN B** command execution	Testing, Control	42
OCC	Asserts for one processing interval for **OPEN C** command execution	Testing, Control	42
OPTMN3P	Reclosing relay open interval timer is timing (available when setting ESPB := N) (see *Figure 6.1*)	Testing	69
OPTMNA, OPTMNB, OPTMNC	A-, B-, or C-phase reclosing relay open interval timer is timing (available when setting ESPB := Y) (see *Figure 6.1*)	Testing	69
OREDHIF2	Asserts if high-impedance fault detected on A-, B-, or C-phase (see *High-Impedance Fault Detection (Arc Sense Technology) on page 4.111*)	Testing, Control	127
OUT101–OUT108	Output contacts OUT101–OUT108, asserted (optional outputs) (see *Output Contacts on page 7.34*)	Indication (only operable if optional I/O installed)	75
OUT201–OUT202	Output contact OUT201 or OUT202, asserted (see *Output Contacts on page 7.34*)	Indication	76
P5ASEL	Asserted when port 5A is active (see *Section 10: Communications*) (only on relays with dual Ethernet connectors)	Indication, Testing	99
P5BSEL	Asserted when port 5B is active (see *Section 10: Communications*) (only on relays with dual Ethernet connectors)	Indication, Testing	99
PASNVAL	Pulses for approximately one second when an incorrect password is entered when attempting to enter Access Level B or higher, or when changing passwords (see *Port Access Levels on page 10.21*)	Indication	107
PB01_LED–PB12_LED	Operator control pushbutton LEDs 01–12. Driven by associated SELOGIC front-panel settings PB01_LED-PB12_LED (see *Operator Controls on page 11.22*).	Indication	36, 37
PB01_PUL–PB12_PUL	Operator control pushbutton 01–12, momentarily pulsed (one processing interval assertion when button is first pressed) (see *Operator Controls on page 11.22*).	Indication	91, 93

Table F.2   Alphabetic List of Relay Word Bits (Sheet 10 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
PB01–PB12	Operator control pushbuttons 01–12 (asserted when button is being pressed) (see *Operator Controls on page 11.22*)	Indication	90, 92
PDEM	Maximum-phase demand current element (see *Figure 8.4*)	Indication	74
PHASE_A, PHASE_B, PHASE_C	A-, B-, or C-phase target logic output (see *Table 5.3*)	Indication	20
PMDOK	Phasor measurement data OK (see *Synchrophasor Relay Word Bits on page J.16*)	Synchrophasors	105
PMTRIG	Phasor Measurement Unit SELOGIC control equation trigger (see *Appendix J: Synchrophasors*). Sent with C37.118 synchrophasor message.	Indication, Synchrophasors	105
PWR_SRC1	Recloser control power supply is operating from external power source (e.g., 120 Vac) (see *Factory-Default 79CLS Settings Example on page 6.14*)	Indication	38
QDEM	Negative-sequence demand current element (see *Figure 8.4*)	Indication	74
R32P	Reverse positive-sequence voltage-polarized directional element (see *Figure 4.60*)	Testing, Special directional control schemes	72
R32Q	Reverse negative-sequence voltage-polarized directional element (see *Figure 4.59*)	Testing, Special directional control schemes	71
R32QG	Reverse negative-sequence voltage-polarized directional element (for ground) (see *Figure 4.55*)	Testing, Special directional control schemes	71
R32V	Reverse zero-sequence voltage-polarized directional element (see *Figure 4.56*)	Testing, Special directional control schemes	72
RB01–RB32	Remote bits 01–32, asserted (see *Remote Bits on page 7.22*)	Control via serial port	94–97
RBADA, RBADB	MIRRORED BITS outage duration over threshold, Channels A and B (see *Table 12.4* and *Appendix D: MIRRORED BITS Communications*)	Indication	84
RCCL1X	Pole 1 recloser close output asserted (see *Figure 7.26*)	Closing	76
RCCL2X	Pole 2 recloser close output asserted (only available for single-phase reclosers) (see *Figure 7.26*)	Closing	76
RCCL3X	Pole 3 recloser close output asserted (only available for single-phase reclosers) (see *Figure 7.26*)	Closing	76
RCSF3P	Reclose supervision failure, asserts for one processing interval (available when setting ESPB := N) (see *Figure 6.1*)	Indication	69
RCSFA, RCSFB, RCSFC	A-, B-, or C-phase reclose supervision failure, asserts for one processing interval (available when setting ESPB := Y) (see *Figure 6.1*)	Indication	69
RCTR1X	Pole 1 recloser trip output asserted (see *Figure 7.26*)	Tripping	76
RCTR2X	Pole 2 recloser trip output asserted (only available for single-phase reclosers) (see *Figure 7.26*)	Tripping	76
RCTR3X	Pole 3 recloser trip output asserted (only available for single-phase reclosers) (see *Figure 7.26*)	Tripping	76
RMB1A–RMB8A	Received MIRRORED BITS 1–8, channel A (see *Appendix D: MIRRORED BITS Communications*)	Control	80
RMB1B–RMB8B	Received MIRRORED BITS 1–8, channel B (see *Appendix D: MIRRORED BITS Communications*)	Control	82
ROKA, ROKB	MIRRORED BITS received data OK, Channels A and B (see *Appendix D: MIRRORED BITS Communications*)	Indication	84

Table F.2   Alphabetic List of Relay Word Bits (Sheet 11 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
RST_BK	Reset Breaker Monitor SELOGIC control equation (see *Section 8: Metering and Monitoring*). The relay resets the breaker monitor accumulators when a rising edge is detected on RST_BK.	Indication, Control	98
RST_DEM	Reset Demand Metering SELOGIC control equation (see *Section 8: Metering and Monitoring*). The relay resets the demand metering registers when a rising edge is detected on RST_DEM.	Indication, Control	98
RST_ENE	Reset Energy Metering SELOGIC control equation (see *Section 8: Metering and Monitoring*). The relay resets the energy metering registers when a rising edge is detected on RST_ENE.	Indication, Control	98
RST_HAL	Reset for HALARMA (see *Self-Tests on page 13.7*)	Indication, Control	98
RST_HIS	Reset Event History SELOGIC control equation (see *Section 8: Metering and Monitoring*). The relay clears the event history archive when a rising edge is detected on RST_HIS.	Indication, Control	98
RST_MML	Reset Max/Min Metering SELOGIC control equation (see *Section 8: Metering and Monitoring*). The relay resets the max/min metering registers when a rising edge is detected on RST_MML.	Indication, Control	98
RST_PDM	Reset Peak Demand Metering SELOGIC control equation (see *Section 8: Metering and Monitoring*). The relay resets the peak demand metering registers when a rising edge is detected on RST_PDM.	Indication, Control	98
RSTDNPE	Reset DNP event registers/buffers (see *Reading Relay Events on page E.39*)	Indication, Control	135
RSTMN3P	Reclosing relay reset timer is timing (available when setting ESPB := N) (see *Figure 6.1*)	Testing	70
RSTMNA, RSTMNB, RSTMNC	A-, B-, or C-phase reclosing relay reset timer is timing (available when setting ESPB := Y) (see *Figure 6.1*)	Testing	70
RSTTRGT	Reset Target SELOGIC control equation (see *Programmable Front-Panel Target LEDs on page 5.15*). The relay resets the latching-type front-panel target LEDs when a rising edge is detected on RSTTRGT. This will also reset DNP event data when in single-event mode (see *Reading Relay Events on page E.39* for details).	Indication, Control	98
SAG3P	Three-phase voltage sag element = SAGA AND SAGB AND SAGC (see *Voltage Sag Elements on page 4.60*)	Sag/Swell/Int reporting	85
SAGA, SAGB, SAGC	A-, B-, or C-phase voltage sag elements (see *Voltage Sag Elements on page 4.60*)	Sag/Swell/Int reporting	85
SALARM	Software Alarm (momentary assertion during group, active settings, password and access level changes) (see *Global Enable Settings on page SET.2*)	Indication	106
SC01QD–SC16QD	SELOGIC Counters 01–16, asserted when counter = 0 (see *Figure 7.15*)	Indication	61, 63
SC01QU–SC16QU	SELOGIC Counters 01–16, asserted when counter = Preset value (see *Figure 7.15*)	Indication	60, 62
SETCHG	Pulses for approximately one second whenever settings are changed (see SALARM in *Global Enable Settings on page SET.2*)	Indication	107
SF	Synchronism-check element, slip frequency less than setting 25SF (see *Figure 4.30*)	Testing	30
SFAST	Synchronism-check element, VP frequency greater than VS frequency (fP > fS) (see *Figure 4.30*)	Special control schemes	30
SG1–SG8	Setting group indication, group 1–8, asserted for active group (see *Active Settings Group Indication on page 7.23*)	Indication	78

Table F.2 Alphabetic List of Relay Word Bits (Sheet 12 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
SH03P	Reclosing relay shot counter = 0 (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
SH0A, SH0B, SH0C	A-, B-, or C-phase reclosing relay shot counter = 0 (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
SH13P	Reclosing relay shot counter = 1 (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
SH1A, SH1B, SH1C	A-, B-, or C-phase reclosing relay shot counter = 1 (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
SH23P	Reclosing relay shot counter = 2 (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
SH2A, SH2B, SH2C	A-, B-, or C-phase reclosing relay shot counter = 2 (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65-67
SH33P	Reclosing relay shot counter = 3 (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
SH3A, SH3B, SH3C	A-, B-, or C-phase reclosing relay shot counter = 3 (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
SH43P	Reclosing relay shot counter = 4 (available when setting ESPB := N) (see *Figure 6.1*)	Control	64
SH4A, SH4B, SH4C	A-, B-, or C-phase reclosing relay shot counter = 4 (available when setting ESPB := Y) (see *Figure 6.1*)	Control	65–67
SOTFE	Switch-onto-fault enable logic output (see *SELOGIC Control Equation Functions on page 7.7*)	Testing	43
SOTFT	Switch-onto-fault trip (see *Figure 5.1*)	Testing, Indication	43
SPE	Single-phase mode enabled (asserted when setting ESPB := Y) (see *Overcurrent Element Torque-Control Setting Application on page 5.10*)	Indication	19
SPO	Single-pole/phase open condition (see *Figure 5.5*)	Indication	18
SPOA, SPOB, SPOC	Phase A, B, or C single-pole/phase open conditions (see *Figure 5.5*)	Indication	18
SSLOW	Synchronism-check element, VP frequency less than VS frequency (fP < fS) (see *Figure 4.30*)	Special control schemes	30
SV01–SV64	SELOGIC variables 01–64. Associated timers (below) are picked up when variable is asserted (see *SELOGIC Control Equation Functions on page 7.7*)	Testing, Seal-in functions, etc.	48–59, 100–103
SV01T–SV64T	SELOGIC timers 01–64, timed out when asserted (see *SELOGIC Control Equation Functions on page 7.7*)	Testing, Seal-in functions, etc.	48–59, 100–103
SW1	Recloser status "Switch 1" derived from inputs (only available for traditional retrofit reclosers, otherwise, it evaluates to logical 0) (see *Factory 52A Settings Example (Traditional Retrofit Recloser) on page 6.4*).	Indication	19
SW3P	Three-phase voltage swell element = SWA AND SWB AND SWC (see *Voltage Swell Elements on page 4.60*)	Sag/Swell/Int reporting	85
SWA, SWB, SWC	A-, B-, or C-phase voltage swell elements (see *Voltage Swell Elements on page 4.60*)	Sag/Swell/Int reporting	85
TCCAP	Recloser interface trip and close capacitor fully charged (see *Factory-Default 79CLS Settings Example on page 6.14*)	Indication, Control	39
TESTDB	Test DataBase command active. Asserts when analog and digital values reported via DNP, Modbus, IEC 61850, or Fast Meter protocol may be overridden (see *Section 10: Communications*).	Testing	87

Table F.2   Alphabetic List of Relay Word Bits (Sheet 13 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
TIRIG	Relay Time is based on IRIG-B time source (see *Synchrophasor Relay Word Bits on page J.16*)	Synchrophasors	105
TLED_01–TLED_24	Target LEDs 01–24. Asserted when LED illuminated (see *Front-Panel Target LEDs on page 5.13*)	Indication	1–3
TMB1A–TMB8A	Transmit MIRRORED BITS 1–8, channel A (see *Appendix D: MIRRORED BITS Communications*)	Control	81
TMB1B–TMB8B	Transmit MIRRORED BITS 1–8, channel B (see *Appendix D: MIRRORED BITS Communications*)	Control	83
TOSLP	To Sleep. Asserts for last minute of control operation on battery power (see *SEL-651R-2 Puts Itself to Sleep on page 8.40*)	Indication	38
TQUAL1–TQUAL4	Encoded IRIG time quality bits 1–4. Only available when Global setting IRIGC = C37.118 and a proper IRIG signal is decoded.	Indication	104
TREA1–TREA4	Trigger Reason bits 1–4 (follow SELOGIC control equations of same name (see *Appendix J: Synchrophasors*). Sent with C37.118 synchrophasor message.	Indication, Synchrophasors	105
TRGTR	Target Reset, button or command, asserts for one processing interval (see *Programmable Front-Panel Target LEDs on page 5.15*)	Control	43
TRIP3P	Trip logic output asserted (available when setting ESPB := N) (see *Figure 5.1*)	Indication	43
TRIPA, TRIPB, TRIPC	Phase A, B, or C trip logic output asserted (available when setting ESPB := Y) (see *Figure 5.1*)	Indication	43
TRIPLED	Trip target LED. Asserted when TRIP LED illuminated. (see *Front-Panel Target LEDs ENABLED and TRIP on page 5.15*)	Indication	0
TSNTPB	Asserts when relay time is based on Simple Network Time Protocol (SNTP) backup server (see *Simple Network Time Protocol (SNTP) on page 10.15*).	Indication	99
TSNTPP	Asserts when relay time is based on Simple Network Time Protocol (SNTP) primary server (see *Simple Network Time Protocol (SNTP) on page 10.15*).	Indication	99
TSOK	Time synchronization OK (see *Synchrophasor Relay Word Bits on page J.16*)	Synchrophasors	105
ULCL3P	Unlatch close condition. Driven by associated SELOGIC Group setting ULCL3P (see *Close Logic on page 6.5*)	Control	70
ULCLA, ULCLB, ULCLC	Phase A, B, or C unlatch close condition. Driven by associated SELOGIC Group settings ULCLA, ULCLB, or ULCLC (see *Close Logic on page 6.5*).	Control	70
V1GOOD	Positive-sequence voltage greater than setting VNOM • 0.85 (see *Loss-of-Potential Logic on page 4.77*)	Indication	19
VB001–VB128	Virtual bits 001–128. Virtual bit configuration is controlled by loaded CID file (IEC 61850 relay models only). Virtual bits can be configured to follow received GOOSE messages (see *Appendix L: IEC 61850*).	Control	108–123
VPOLV	Positive-sequence polarization voltage valid (see *Directional Elements on page 4.86*)	Testing	19
VSELY	VY voltage inputs selected (asserts when setting VSELECT := VY) (see *Figure 9.22*)	Indication	25
VSELZ	VZ voltage inputs selected (asserts when setting VSELECT := VZ) (see *Figure 9.22*)	Indication	29
XS_CLOS1, XS_CLOS2, XS_CLOS3	Pole 1, 2, or 3: excessive close operations detected (available for single-phase reclosers only)	Indication	39

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Relay Word Bits F.19
Analog Scaling and Frequency Indicators
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Table F.2 **Alphabetic List of Relay Word Bits** (Sheet 14 of 14)

Name	Definition	Usage	Relay Word Bit Row[a]
XS_TRIP1, XS_TRIP2, XS_TRIP3	Pole 1, 2, or 3: excessive trip operations detected (available for single-phase reclosers only)	Indication	39
ZLIN	Load encroachment "load in" element (see *Figure 4.48*)	Special phase overcurrent element control	21
ZLOAD	Load encroachment element = ZLIN OR ZLOUT (see *Figure 4.48*)	Special phase overcurrent element control	21
ZLOUT	Load encroachment "load out" element (see *Figure 4.48*)	Special phase overcurrent element control	21

[a] See Table F.1 for a list of the Relay Word bits by row number.

[b] Time-overcurrent (51) elements have two sets of settings called J and K, each of which includes pickup, curve, time dial, electromechanical reset, constant time adder, and minimum response time. Only one set can be operative for each 51 element. The 51_S Relay Word bit indicates which of these sets is operative for each element. It is deasserted when J settings are in use and asserted when K settings are in use. The relay uses the same output Relay Word bits (51_, 51_R, 51_T), regardless of the J/K selection.

Analog Scaling and Frequency Indicators

The SEL-651R-2 uses the Relay Word bits listed in *Table F.3* for internal operations, such as event report preparation and phasor measurement. the operating criteria for these elements are not exact, so they should not be included in commissioning tests.

Table F.3 **Analog Scaling and Frequency Indicators**

Relay Word Bit	Description	Asserts When:
INMET	Channel IN high-gain mode active	Channel IN current signal is less than the nominal current rating (0.2 A secondary)
ICMET	Channel IC high-gain mode active	Channel IC current signal is less than the nominal current rating (1 A secondary)
IBMET	Channel IB high-gain mode active	Channel IB current signal is less than the nominal current rating (1 A secondary)
IAMET	Channel IA high-gain mode active	Channel IA current signal is less than the nominal current rating (1 A secondary)
FREQOK	System frequency and tracking frequency valid	System frequency measurement source is healthy (see *Frequency Source Selection Setting (FSELECT) on page 9.33*), the frequency is between 40 Hz and 65 Hz, and the rate-of-change of frequency is less than 20 Hz/s.

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Appendix G

Analog Quantities

The SEL-651R-2 Recloser Control contains several analog quantities that can be used for more than one function.

Analog quantities are typically generated and used by a primary function, such as metering, and selected quantities are made available for one or more supplemental functions, such as the load profile recorder.

SEL-651R-2 analog quantities are generated by the following:

> ➤ Metering functions (see *Section 8: Metering and Monitoring*)

> ➤ Recloser/breaker monitor (see *Section 8: Metering and Monitoring*)

> ➤ Self-Test diagnostics (see *Section 13: Testing and Troubleshooting*)

> ➤ DNP Communications Statistics (see *Appendix E: DNP3 Communications*)

> ➤ Relay settings (see *Section 9: Settings*)

> ➤ System date and time (see *Section 10: Communications*)

> ➤ SELOGIC counters (see *Section 7: SELOGIC Control Equation Programming*)

> ➤ Reclosing relay logic (see *Section 6: Close and Reclose Logic*)

Table G.1 provides a complete list of analog quantities that can be used in the following interfaces (when marked with an "x"):

> ➤ Display points (see *Rotating Display on page 11.13*)

> ➤ Load profile recorder (see *Load Profile Report on page 8.44*)

> ➤ DNP3 (see *Appendix E: DNP3 Communications*)

> ➤ Modbus (see *Appendix K: Modbus RTU and TCP Communications*)

> ➤ SEL Fast Meter protocol (see *Appendix I: Configuration, Fast Meter, and Fast Operate Commands*)

> ➤ IEC 61850 protocol (see *Appendix L: IEC 61850*)

See *Table 7.2* for a list of analog quantities that can be used in analog comparisons in SELOGIC control equations.

Table G.1 Analog Quantities (Sheet 1 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
Fundamental Metering								
IA, IB, IC	Phase (A, B, C) current magnitudes	A pri	x	x	x	x	x	x
IAFA, IBFA, ICFA	Phase (A, B, C) current angles	degrees			x	x	x	x
IN	Neutral (channel IN) current magnitude	A pri	x	x	x	x	x	x
INFA	Neutral (channel IN) current angle	degrees			x	x	x	x
IG	Ground current magnitude[a]	A pri	x	x	x	x		x
IGFA	Ground current angle[a]	degrees			x	x		x
3I0, I1, 3I2	Sequence current magnitudes	A pri	x	x	x	x		x
3I0FA, I1FA, 3I2FA	Sequence current angles	degrees			x	x		x
VAY, VBY, VCY, VAZ, VBZ, VCZ	Phase (A, B, C) voltage magnitudes for Y- and Z-terminals	kV pri	x	x	x			x
VAY, VBY, VCY, VAZ, VBZ, VCZ	Phase (A, B, C) voltage magnitudes for Y- and Z-terminals	V pri				x	x	
VAYFA, VBYFA, VCYFA, VAZFA, VBZFA, VCZFA	Phase (A, B, C) voltage angles for Y- and Z-terminals	degrees			x	x	x	x
VABY, VBCY, VCAY, VABZ, VBCZ, VCAZ	Phase-to-phase (AB, BC, CA) voltage magnitudes for Y- and Z-terminals	kV pri	x	x	x			x
VABY, VBCY, VCAY, VABZ, VBCZ, VCAZ	Phase-to-phase (AB, BC, CA) voltage magnitudes for Y- and Z-terminals	V pri				x		
VABYFA, VBCYFA, VCAYFA, VABZFA, VBCZFA, VCAZFA	Phase-to-phase (AB, BC, CA) voltage angles for Y- and Z-terminals	degrees			x	x		x
V1Y, V2Y, 3V0Y, V1Z, V2Z, 3V0Z	Positive-, negative-, and zero-sequence voltage magnitudes for Y- and Z-terminals	kV pri	x	x	x			x
V1Y, V2Y, 3V0Y, V1Z, V2Z, 3V0Z	Positive-, negative-, and zero-sequence voltage magnitudes for Y- and Z-terminals	V pri				x		
V1YFA, V2YFA, 3V0YFA, V1ZFA, V2ZFA, 3V0ZFA	Positive-, negative-, and zero-sequence voltage angles for Y- and Z- terminals	degrees			x	x		x
MVAA, MVAB, MVAC	Phase (A, B, C) apparent power	MVA	x	x	x			
KVAA, KVAB, KVAC	Phase (A, B, C) apparent power	kVA				x		x
MVA3	Three-phase apparent power	MVA	x	x	x			
KVA3	Three-phase apparent power	kVA				x		x
MWA, MWB, MWC	Phase (A, B, C) real power	MW	x	x	x			
KWA, KWB, KWC	Phase (A, B, C) real power	kW				x		x
MW3	Three-phase real power	MW	x	x	x			
KW3	Three-phase real power	kW				x		x
MVARA, MVARB, MVARC	Phase (A, B, C) reactive power	MVAR	x	x	x			
KVARA, KVARB, KVARC	Phase (A, B, C) reactive power	kVAR				x		x
MVAR3	Three-phase reactive power	MVAR	x	x	x			
KVAR3	Three-phase reactive power	kVAR				x		x

Table G.1   Analog Quantities (Sheet 2 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
PFA, PFB, PFC	Phase (A, B, C) power factor	per unit	x[b]	x	x	x		x
PF3	Three-phase power factor	per unit	x[b]	x	x	x		x
LDPFA, LDPFB, LDPFC	Phase (A, B, C) power factor leading	0 or 1	x	x	x	x		
LDPF3	Three-phase power factor leading	0 or 1	x	x	x	x		
FREQ	Frequency	Hz	x	x	x	x	x	x
Demand Metering								
IADEM, IBDEM, ICDEM	Phase (A, B, C) current magnitudes	A pri	x	x	x	x	x	x
INDEM	Neutral (channel IN) current magnitude	A pri	x	x	x	x	x	x
IGDEM	Ground current magnitude[a]	A pri	x	x	x	x	x	x
3I2DEM	Negative-sequence current magnitude	A pri	x	x	x	x	x	x
MVAAD, MVABD, MVACD	Phase (A, B, C) apparent power	MVA	x	x	x			
KVAAD, KVABD, KVACD	Phase (A, B, C) apparent power	kVA				x		
MVA3D	Three-phase apparent power	MVA	x	x	x			
KVA3D	Three-phase apparent power	kVA				x		
MWADI, MWBDI, MWCDI	Phase (A, B, C) real power in	MW	x	x	x		x	
KWADI, KWBDI, KWCDI	Phase (A, B, C) real power in	kW				x		
MW3DI	Three-phase real power in	MW	x	x	x		x	
KW3DI	Three-phase real power in	kW				x		
MWADO, MWBDO, MWCDO	Phase (A, B, C) real power out	MW	x	x	x		x	
KWADO, KWBDO, KWCDO	Phase (A, B, C) real power out	kW				x		
MW3DO	Three-phase real power out	MW	x	x	x		x	
KW3DO	Three-phase real power out	kW				x		
MVRADI, MVRBDI, MVRCDI	Phase (A, B, C) reactive power in	MVAR	x	x	x		x	
KVRADI, KVRBDI, KVRCDI	Phase (A, B, C) reactive power in	kVAR				x		
MVR3DI	Three-phase reactive power in	MVAR	x	x	x		x	
KVR3DI	Three-phase reactive power in	kVAR				x		
MVRADO, MVRBDO, MVRCDO	Phase (A, B, C) reactive power out	MVAR	x	x	x		x	
KVRADO, KVRBDO, KVRCDO	Phase (A, B, C) reactive power out	kVAR				x		
MVR3DO	Three-phase reactive power out	MVAR	x	x	x		x	
KVR3DO	Three-phase reactive power out	kVAR				x		

Table G.1 Analog Quantities (Sheet 3 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
Peak (Demand) Metering								
IAPK, IBPK, ICPK	Phase (A, B, C) current magnitudes	A pri	x		x	x	x	x
INPK	Neutral (channel IN) current magnitude	A pri	x		x	x	x	x
IGPK	Ground current magnitude[a]	A pri	x		x	x	x	x
3I2PK	Negative-sequence current magnitude	A pri	x		x	x	x	x
MVAAP, MVABP, MVACP	Phase (A, B, C) apparent power	MVA	x		x			
KVAAP, KVABP, KVACP	Phase (A, B, C) apparent power	kVA				x		
MVA3P	Three-phase apparent power	MVA	x		x			
KVA3P	Three-phase apparent power	kVA				x		
MWAPI, MWBPI, MWCPI	Phase (A, B, C) real power in	MW	x		x		x	
KWAPI, KWBPI, KWCPI	Phase (A, B, C) real power in	kW				x		
MW3PI	Three-phase real power in	MW	x		x		x	
KW3PI	Three-phase real power in	kW				x		
MWAPO, MWBPO, MWCPO	Phase (A, B, C) real power out	MW	x		x		x	
KWAPO, KWBPO, KWCPO	Phase (A, B, C) real power out	kW				x		
MW3PO	Three-phase real power out	MW	x		x		x	
KW3PO	Three-phase real power out	kW				x		
MVRAPI, MVRBPI MVRCPI	Phase (A, B, C) reactive power in	MVAR	x		x		x	
KVRAPI, KVRBPI, KVRCPI	Phase (A, B, C) reactive power in	kVAR				x		
MVR3PI	Three-phase reactive power in	MVAR	x		x		x	
KVR3PI	Three-phase reactive power in	kVAR				x		
MVRAPO, MVRBPO, MVRCPO	Phase (A, B, C) reactive power out	MVAR	x		x		x	
KVRAPO, KVRBPO, KVRCPO	Phase (A, B, C) reactive power out	kVAR				x		
MVR3PO	Three-phase reactive power out	MVAR	x		x		x	
KVR3PO	Three-phase reactive power out	kVAR				x		
Energy Metering								
MWHAI, MWHBI, MWHCI	Phase (A, B, C) real energy in	MWh	x	x	x	x		
MWH3I	Three-phase real energy in	MWh	x	x	x	x		x
MWHAO, MWHBO, MWHCO	Phase (A, B, C) real energy out	MWh	x	x	x	x		
MWH3O	Three-phase real energy out	MWh	x	x	x	x		x

Table G.1   Analog Quantities (Sheet 4 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
MVRHAI, MVRHBI, MVRHCI	Phase (A, B, C) reactive energy in	MVARh	x	x	x	x		
MVRH3I	Three-phase reactive energy in	MVARh	x	x	x	x		x
MVRHAO, MVRHBO, MVRHCO	Phase (A, B, C) reactive energy out	MVARh	x	x	x	x		
MVRH3O	Three-phase reactive energy out	MVARh	x	x	x	x		x
Max/Min Metering								
IAMAX, IBMAX, ICMAX	Maximum phase (A, B, C) current magnitude	A pri			x	x		x
IAMXD_[x][c], IBMXD_[x][c], ICMXD_[x][c]	Maximum phase (A, B, C) current magnitudes date	date				x		
IAMXT_[z][d], IBMXT_[z][d], ICMXT_[z][d]	Maximum phase (A, B, C) current magnitudes time	time				x		
INMAX	Maximum neutral (channel IN) current magnitude	A pri			x	x		x
INMXD_[x][c]	Maximum neutral (channel IN) current magnitude date	date				x		
INMXT_[z][d]	Maximum neutral (channel IN) current magnitude time	time				x		
IGMAX	Maximum ground current magnitude[a]	A pri			x	x		x
IGMXD_[x][c]	Maximum ground current magnitude date[a]	date				x		
IGMXT_[z][d]	Maximum ground current magnitude time[a]	time				x		
IAMIN, IBMIN, ICMIN	Minimum phase (A, B, C) current magnitude	A pri			x	x		x
IAMND_[x][c], IBMND_[x][c], ICMND_[x][c]	Minimum phase (A, B, C) current magnitude date	date				x		
IAMNT_[z][d], IBMNT_[z][d], ICMNT_[z][d]	Minimum phase (A, B, C) current magnitude time	time				x		
INMIN	Minimum neutral (channel IN) current magnitude	A pri			x	x		x
INMND_[x][c]	Minimum neutral (channel IN) current magnitude date	date				x		
INMNT_[z][d]	Minimum neutral (channel IN) current magnitude time	time				x		
IGMIN	Minimum ground current magnitude[a]	A pri			x	x		x
IGMND_[x][c]	Minimum ground current magnitude date[a]	date				x		
IGMNT_[z][d]	Minimum ground current magnitude time[a]	time				x		

Table G.1 Analog Quantities (Sheet 5 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
VAYMAX, VBYMAX, VCYMAX, VAZMAX, VBZMAX, VCZMAX	Maximum phase (A, B, C) voltage magnitudes for Y- and Z-terminals	kV pri			x			x
VAYMAX, VBYMAX, VCYMAX, VAZMAX, VBZMAX, VCZMAX	Maximum phase (A, B, C) voltage magnitudes for Y- and Z-terminals	V pri				x		
VAYMXD_[x][c], VBYMXD_[x][c], VCYMXD_[x][c], VAZMXD_[x][c], VBZMXD_[x][c], VCZMXD_[x][c]	Maximum phase (A, B, C) voltage magnitudes for Y- and Z-terminals date	date				x		
VAYMXT_[z][d], VBYMXT_[z][d], VCYMXT_[z][d], VAZMXT_[z][d], VBZMXT_[z][d], VCZMXT_[z][d]	Maximum phase (A, B, C) voltage magnitudes for Y- and Z-terminals time	time				x		
VAYMIN, VBYMIN, VCYMIN, VAZMIN, VBZMIN, VCZMIN	Minimum phase (A, B, C) voltage magnitudes for Y- and Z-terminals	kV pri			x			x
VAYMIN, VBYMIN, VCYMIN, VAZMIN, VBZMIN, VCZMIN	Minimum phase (A, B, C) voltage magnitudes for Y- and Z-terminals	V pri				x		
VAYMND_[x][c], VBYMND_[x][c], VCYMND_[x][c], VAZMND_[x][c], VBZMND_[x][c], VCZMND_[x][c]	Minimum phase (A, B, C) voltage magnitudes for Y- and Z-terminals date	date				x		
VAYMNT_[z][d], VBYMNT_[z][d], VCYMNT_[z][d], VAZMNT_[z][d], VBZMNT_[z][d], VCZMNT_[z][d]	Minimum phase (A, B, C) voltage magnitudes for Y- and Z-terminals time	time				x		
MVA3MAX	Maximum three-phase apparent power	MVA			x			x
KVA3MAX	Maximum three-phase apparent power	kVA				x		
KVA3XD_[x][c]	Maximum three-phase apparent power date	date				x		
KVA3XT_[z][d]	Maximum three-phase apparent power time	time				x		
MW3MAX	Maximum three-phase real power	MW			x			x
KW3MAX	Maximum three-phase real power	kW				x		
KW3MND_[x][c]	Maximum three-phase real power date	date				x		
KW3MNT_[z][d]	Maximum three-phase real power time	time				x		
MVR3MAX	Maximum three-phase reactive power	MVAR			x			x
KVR3MAX	Maximum three-phase reactive power	kVAR				x		
KVR3XD_[x][c]	Maximum three-phase reactive power date	date				x		
KVR3XT_[z][d]	Maximum three-phase reactive power time	time				x		

Table G.1 Analog Quantities (Sheet 6 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
MVA3MIN	Minimum three-phase apparent power	MVA			x			x
KVA3MIN	Minimum three-phase apparent power	kVA				x		
KVA3ND_[x][c]	Minimum three-phase apparent power date	date				x		
KVA3NT_[z][d]	Minimum three-phase apparent power time	time				x		
MW3MIN	Minimum three-phase real power	MW			x			x
KW3MIN	Minimum three-phase real power	kW				x		
KW3MXD_[x][c]	Minimum three-phase real power date	date				x		
KW3MXT_[z][d]	Minimum three-phase real power time	time				x		
MVR3MIN	Minimum three-phase reactive power	MVAR			x			x
KVR3MIN	Minimum three-phase reactive power	kVAR				x		
KVR3ND_[x][c]	Minimum three-phase reactive power date	date				x		
KVR3NT_[z][d]	Minimum three-phase reactive power time	time				x		
RMS Metering								
IAR, IBR, ICR	Phase (A, B, C) rms current	A pri	x	x	x	x		
INR	Neutral (channel IN) rms current	A pri	x	x	x	x		
VAYR, VBYR, VCYR, VAZR, VBZR, VCZR	Phase (A, B, C) rms voltage for Y- and Z-terminals	kV pri	x	x	x			
VAYR, VBYR, VCYR, VAZR, VBZR, VCZR	Phase (A, B, C) rms voltage for Y- and Z-terminals	V pri				x		
MWAR, MWBR, MWCR	Phase (A, B, C) average real power	MW	x	x	x			x
KWAR, KWBR, KWCR	Phase (A, B, C) average real power	kW				x		
MW3R	Three-phase average real power	MW	x	x	x			x
KW3R	Three-phase average real power	kW				x		
Harmonics Metering								
IAHT, IBHT, ICHT	Phase (A, B, C) current THD	%	x	x	x	x		
INHT	Neutral (channel IN) current THD	%	x	x	x	x		
IAH01, IBH01, ICH01[e]	Phase (A, B, C) current Fundamental Magnitude (harmonic metering)	A pri			x	x		
INH01[e]	Neutral (channel IN) current Fundamental Magnitude (harmonic metering)	A pri			x	x		
IAH*nn*, IBH*nn*, ICH*nn*	Phase (A, B, C) current Harmonic *nn* (*nn* = 02–16)	%			x	x		
INH*nn*	Neutral (channel IN) current Harmonic *nn* (*nn* = 02–16)	%			x	x		
VAYHT, VBYHT, VCYHT, VAZHT, VBZHT, VCZHT	Phase (A, B, C) voltage THD for Y- and Z-terminals	%	x	x	x	x		

Table G.1   Analog Quantities (Sheet 7 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
VAYH01, VBYH01, VCYH01, VAZH01, VBZH01, VCZH01[e]	Phase (A, B, C) voltage Fundamental magnitudes for Y- and Z-terminals (harmonic metering)	kV			x			
VAYH01, VBYH01, VCYH01, VAZH01, VBZH01, VCZH01[e]	Phase (A, B, C) voltage Fundamental magnitudes for Y- and Z-terminals (harmonic metering)	V				x		
VAYH*nn*, VBYH*nn*, VCYH*nn*, VAZH*nn*, VBZH*nn*, VCZH*nn*	Phase (A, B, C) voltage Harmonics *nn* (*nn* = 02–16) for Y- and Z-terminals	%			x	x		
Breaker Monitor								
BRKDAT	Last Reset date and time	date/time	x					
INTTA, INTTB, INTTC	Phase (A, B, C) Internal Trip Counter	count	x		x[f]	x		
INTIA, INTIB, INTIC	Phase (A, B, C) Internal Trip Accumulated current	kA pri	x		x	x		
EXTTA, EXTTB, EXTTC	Phase (A, B, C) External Trip Counter	count	x		x[f]	x		
EXTIA, EXTIB, EXTIC	Phase (A, B, C) External Trip Accumulated current	kA pri	x		x	x		
OPSCTRA, OPSCTRB, OPSCTRC	Phase (A, B, C) Total Internal and External Trip Counter	count	x	x	x[f]	x		x
APHTR, BPHTR, CPHTR	Phase (A, B, C) Involvement Counter	count	x		x[f]	x		
GNDCTR	Ground Involvement Counter	count	x		x[f]	x		
WEARA, WEARB, WEARC	Phase (A, B, C) Breaker Wear Percentage	%	x	x	x	x		x
MAXWEAR	Greatest wear of WEARA, WEARB, or WEARC	%	x	x	x	x		x
BKTYP	Breaker Type, according to Global setting BKTYP		x		x	x		
Event History								
NUMEVE	Event History Number	count				x		
EVESEL	Selected History Number	count				x		
FDATE_Y	Fault date—Year portion	year				x		
FDATE_M	Fault date—Month portion	month				x		
FDATE_D	Fault date—Day portion	day				x		
FTIME_H	Fault time—Hour portion	hour				x		
FTIME_M	Fault time—Minute portion	minute				x		
FTIME_S	Fault time—Second portion	second				x		
FTIMEH	Fault date/time stamp—High word	binary			x			
FTIMEH16	Fault date/time stamp—High word formatted as a 16-bit signed value	binary			x			
FTIMEM	Fault date/time stamp—Middle word	binary			x			
FTIMEM16	Fault date/time stamp—Middle word formatted as a 16-bit signed value	binary			x			
FTIMEL	Fault date/time stamp—Low word	binary			x			

Table G.1 Analog Quantities (Sheet 8 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
FTIMEL16	Fault date/time stamp—Low word formatted as a 16-bit signed value	binary			x			
FTYPE	Fault Type				x			
FTYPE16	Fault Type formatted as a 16-bit signed value				x			
EVE_TYPE	Event Type					x		
FLOC	Fault Location	LL units			x	x		
FI	Fault current Maximum of IA, IB, IC	A pri			x	x		
FIA, FIB, FIC	Fault current, A, B, or C-phase	A pri			x	x		
FIG	Fault current, residual ground (IG = 3I0)[a]	A pri			x	x		
FIQ	Fault current, negative-sequence (3I2)	A pri			x	x		
FTARHI	Fault targets - high word				x	x		
FTARLO	Fault targets - how word				x	x		
FFREQ	Event frequency	Hz			x	x		
FGRP	Setting group active at event trigger	count			x	x		
FSHO	Reclosing relay shot counter at event trigger	count			x	x		
FUNR	Number of unread faults	count			x			
FUNRC	Number of unread faults	count			x[f]			
FLRNUM	Unique Identification number of the latest event	unitless						x
FLREP	Event Report Present (shall be 1 when an event report is present and 0 otherwise)	0 or 1						x
HIFLRNUM	Unique Identification number of the latest HIF event	unitless						x
HIFLREP	Event Report Present (shall be 1 when an HIF event report is present, and 0 otherwise)	0 or 1						x
Diagnostics								
P5V_PS	+5 Volt power supply	Vdc			x	x		
P5V_REG	+5 Volt Regulated power supply	Vdc			x	x		
P15V_PS	+15 Volt power supply	Vdc			x	x		
N15V_PS	–15 Volt power supply	Vdc			x	x		
P12V_TC	+12 Volt trip/close capacitors control supply	Vdc			x	x		
P5VA_PS	+5 Volt analog power supply	Vdc			x	x		
N5VA_PS	–5 Volt analog power supply	Vdc			x	x		
TEMP	Temperature	Deg C	x		x	x		
CMODE	Battery or capacitor charger mode				x	x		
VBAT	Battery voltage	Vdc	x	x	x	x		x
IBAT	Battery current (negative indicates discharge)	A dc	x		x	x		

Table G.1   Analog Quantities (Sheet 9 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
TBAT	Battery temperature	Deg C			x	x		
INPBV	Input power Bus voltage	Vdc			x	x		
12VAUX	+12 V auxiliary power supply	Vdc			x	x		
TCCAPV	Trip/close capacitor voltage	Vdc	x		x	x		
Settings Group, Date, and Time								
ACTGRP	Active settings group	count			x[g]	x		
DATE	Present date from relay clock	date	x				x	
TIME	Present time from relay clock	time	x				x	
DATE_Y	Present date—year portion	year				x		
DATE_M	Present date—month portion	month				x		
DATE_D	Present date—day portion	day				x		
TIME_H	Present time—hour portion	hour				x		
TIME_M	Present time—minute portion	minute				x		
TIME_S	Present time—second portion	second				x		
Relay Information								
FID	Relay firmware string							x
FWREV	Relay firmware revision				x	x		
FWVNUM	Relay firmware version number				x	x		
SNUMBL	Relay serial number, lowest 4 digits				x	x		
SNUMBM	Relay serial number, middle 4 digits				x	x		
SNUMBH	Relay serial number, highest 4 digits				x	x		
SERNUM	Relay serial number string							x
DNPADR	DNP slave address of relay				x			
REPADR	DNP master address				x			
Modbus Communications Counters								
MSGRCD	Number of messages received	count				x		
MSGOID	Number of messages to other devices (Other ID)	count				x		
ILLADDR	Illegal address count	count				x		
BADCRC	Bad CRC count	count				x		
UARTER	Uart error count	count				x		
ILLFUNC	Illegal function count	count				x		
ILLREG	Illegal register count	count				x		
ILLDATA	Illegal data count	count				x		
BADPF	Bad packet format count	count				x		
BADPL	Bad packet length count	count				x		
Math Variables								
MV01–MV64	Math variable		x		x	x		x

Table G.1   Analog Quantities (Sheet 10 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
SELOGIC Counters								
SC01–SC16	SELOGIC counter *nn* present value (where *nn* = 01–16) count		x	x	x	x		x
Identifier Labels								
RID	Relay identifier		x					
TID	Terminal identifier		x					
Pickup Settings, 51h								
51PJP, 51PKP	Maximum-phase time-overcurrent element (J, K) pickup	A sec	x		x			
51AJP, 51BJP, 51CJP, 51AKP, 51BKP, 51CKP	Phase (A, B, C) time-overcurrent element (J, K) pickup	A sec	x		x			
51N1JP, 51N1KP	Neutral (#1) time-overcurrent element (J, K) pickup	A sec	x		x			
51N2JP, 51N2KP	Neutral (#2) time-overcurrent element (J, K) pickup	A sec	x		x			
51G1JP, 51G1KP	Ground (#1) time-overcurrent element (J, K) pickup	A sec	x		x			
51G2JP, 51G2KP	Ground (#2) time-overcurrent element (J, K) Pickup	A sec	x		x			
51QJP, 51QKP	Negative-Sequence time-overcurrent element (J, K) pickup	A sec	x		x			
51PJP_P, 51PKP_P	Maximum-phase time-overcurrent element (J, K) pickup	A pri	x		x			
51AJP_P, 51BJP_P, 51CJP_P, 51AKP_P, 51BKP_P, 51CKP_P,	Phase (A, B, C) time-overcurrent element (J, K) pickup	A pri	x		x			
51N1JP_P, 51N1KP_P	Neutral (#1) time-overcurrent element (J, K) pickup	A pri	x		x			
51N2JP_P, 51N2KP_P	Neutral (#2) time-overcurrent element (J, K) pickup	A pri	x		x			
51G1JP_P[i], 51G1KP_P[i]	Ground (#1) time-overcurrent element (J, K) pickup	A pri	x		x			
51G2JP_P[i], 51G2KP_P[i]	Ground (#2) time-overcurrent element (J, K) pickup	A pri	x		x			
51QJP_P, 51QKP_P	Negative-sequence time-overcurrent element (J, K) pickup	A pri	x		x			
Curve Settings 51h								
51PJC, 51PKC	Maximum-phase time-overcurrent element (J, K) curve	Curve	x					
51AJC, 51BJC, 51CJC, 51AKC, 51BKC, 51CKC	Phase (A, B, C) time-overcurrent element (J, K) curve	Curve	x					
51N1JC, 51N1KC	Neutral (#1) time-overcurrent element (J, K) curve	Curve	x					
51N2JC, 51N2KC	Neutral (#2) time-overcurrent element (J, K) curve	Curve	x					
51G1JC, 51G1KC	Ground (#1) time-overcurrent element (J, K) curve	Curve	x					

Table G.1 Analog Quantities (Sheet 11 of 11)

Label	Description	Units	Display Points	Load Profile	DNP3	Modbus	Fast Meter	IEC 61850
51G2JC, 51G2KC	Ground (#2) time-overcurrent element (J, K) curve	Curve	x					
51QJC, 51QKC	Negative-Sequence time-overcurrent element (J, K) curve	Curve	x					
Time Dial Settings, 51[h]								
51PJTD, 51PKTD	Maximum-phase time-overcurrent element (J, K) time dial	Time Dial	x					
51AJTD, 51BJTD, 51CJTD, 51AKTD, 51BKTD, 51CKTD	Phase (A, B, C) time-overcurrent element (J, K) time dial	Time Dial	x					
51N1JTD, 51N1KTD	Neutral (#1) time-overcurrent element (J, K) time dial	Time Dial	x					
51N2J5D, 51N2KTD	Neutral (#2) time-overcurrent element (J, K) time dial	Time Dial	x					
51G1JTD, 51G1KTD	Ground (#1) time-overcurrent element (J, K) time dial	Time Dial	x					
51G2JTD, 51G2KTD	Ground (#2) time-overcurrent element (J, K) time dial	Time Dial	x					
51QJTD, 51QKTD	Negative-Sequence time-overcurrent element (J, K) time dial	Time Dial	x					

[a]   When Global setting EGNDSW := Y, the metering ground current quantity IG automatically switches between 3I0 and IN, depending on the magnitude of the measured ground current. The metering IG quantity (A primary) is based on the IN channel for small signals and the 3I0 quantity for larger signals.
When Global setting EGNDSW := N, the ground current quantity IG is always based on 3I0 = IA + IB + IC (in A primary).
See Ground Switch Option on page 8.3 for more details.

[b]   Lag or lead is automatically included in Display Points for power factor. For example, setting "DP02 = PFA" will display PF A = 0.76 LAG as display point 2.

[c]   Modbus date values are available as day, month, and year: [x] = D, M, Y.

[d]   Modbus time values are available as seconds, minutes, and hours; [z] = S, M, H.

[e]   The first harmonic (01) is also called the "fundamental" component and comes from the harmonic metering subsystem. This quantity may be different than the quantity from the fundamental metering subsystem because the relay calculates the two numbers by using different methods. For example, VBYH01 may not exactly match VBY (from Fundamental Metering).

[f]   Available in DNP as a counter input.

[g]   Available in DNP as both a counter input and analog output.

[h]   The time-overcurrent elements have two sets of settings, called J and K. Only one of these sets is operative at any time. J/K selection is controlled by the 51_SW SELogic Group setting for each of the 51_ elements.

[i]   When Global setting EGNDSW := Y, the primary ground pickup is calculated using CTRN. When Global setting EGNDSW := N, the primary ground pickup is calculated using CTR. See Ground Switch Option on page 8.3.

Appendix H

Fast SER Protocol

Introduction

This appendix describes special binary Fast Sequential Events Recorder (SER) messages that are not included in *Section 10: Communications* of this instruction manual. Devices with embedded processing capability can use these messages to enable and accept unsolicited binary Fast SER messages from the SEL-651R-2 Recloser Control.

SEL relays and communications processors have two separate data streams that share the same serial port. The normal serial interface consists of ASCII character commands and reports that are intelligible to people using a terminal or terminal emulation package. The binary data streams can interrupt the ASCII data stream to obtain information, and then allow the ASCII data stream to continue. This mechanism allows a single communications channel to be used for ASCII communications (e.g., transmission of a long event report) interleaved with short bursts of binary data to support fast acquisition of metering or SER data. To exploit this feature, the device connected to the other end of the link requires software that uses the separate data streams. The binary commands and ASCII commands can also be accessed by a device that does not interleave the data streams.

Make Sequential Events Recorder (SER) Settings With Care

The relay triggers a row in the Sequential Events Recorder (SER) event report for any change of state in any one of the elements listed in the SER1, SER2, SER3, or SER4 trigger settings. Nonvolatile memory is used to store the latest 1024 rows of the SER event report so they can be retained during power loss. The nonvolatile memory is rated for a finite number of "writes." Exceeding the limit can result in an EEPROM self-test failure. An average of one state change every three minutes can be made for a 25-year relay service life.

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Recommended Message Usage

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Recommended Message Usage

Use the following sequence of commands to enable unsolicited binary Fast SER messaging in the SEL-651R-2:

Step 1. On initial connection, send the **SNS** command to retrieve and store the ASCII names for the digital I/O points assigned to trigger SER records.

The order of the ASCII names matches the point indices in the unsolicited binary Fast SER messages. Send the "Enable Unsolicited Fast SER Data Transfer" message to enable the SEL-651R-2 to transmit unsolicited binary Fast SER messages.

Step 2. When SER records are triggered in the SEL-651R-2, the relay responds with an unsolicited binary Fast SER message. If this message has a valid checksum, it must be acknowledged by sending an acknowledge message with the same response number as contained in the original message. The relay will wait approximately 200–500 ms to receive an acknowledge message, at which time the relay will resend the same unsolicited Fast SER message with the same response number.

Step 3. Upon receiving an acknowledge message with a matching response number, the relay increments the response number and continues to send and seek acknowledgment for unsolicited Fast SER messages if additional SER records are available. When the response number reaches three, it wraps around to zero on the next increment.

Functions and Function Codes

In the messages shown below, all numbers are in hexadecimal unless otherwise noted.

01-Function Code: Enable Unsolicited Fast SER Data Transfer, Sent From Master to Relay

Upon being turned on, the SEL-651R-2 disables its own unsolicited transmissions. This function enables the SEL-651R-2 to begin sending unsolicited data to the device which sent the enable message, if the SEL-651R-2 has such data to transfer. The message format for function code 01 is shown in *Table H.1*.

Table H.1   Function Code 01 Message Format (Sheet 1 of 2)

Data	Description
A546	Message header
12	Message length in bytes (18 decimal)
0000000000	Five bytes reserved for future use as a routing address
YY	Status byte (LSB = 1 indicates an acknowledge is requested)
01	Function code
C0	Sequence byte (Always C0. Other values are reserved for future use in multiple frame messages.)
XX	Response number (XX = 00, 01, 02, 03, 00, 01...).
18	Function to enable (18 unsolicited SER messages)

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Table H.1   Function Code 01 Message Format (Sheet 2 of 2)

Data	Description
0000	Reserved for future use as function code data
nn	Maximum number of SER records per message, 01–20 hex
cccc	Two byte CRC-16 check code for message

The SEL-651R-2 verifies the message by checking the header, length, function code, and enabled function code against the expected values. It also checks the entire message against the CRC-16 field. If any of the checks fail, except the function code or the function to enable, the message is ignored.

If an acknowledge is requested as indicated by the least significant bit of the status byte, the relay transmits an acknowledge message with the same response number received in the enable message.

The *nn* field is used to set the maximum number of SER records per message. The relay checks for SER records approximately every 500 ms. If there are new records available, the relay immediately creates a new unsolicited Fast SER message and transmits it. If there are more than *nn* new records available, or if the first and last record are separated by more than 16 seconds, the relay will break the transmission into multiple messages so that no message contains more than *nn* records, and the first and last record of each message are separated by no more than 16 seconds.

If the function to enable is not 18 or the function code is not recognized, the relay responds with an acknowledge message containing response code 01 (function code unrecognized) and no functions are enabled. If the SER triggers are disabled (SER1, SER2, SER3, and SER4 are all set to NA), the unsolicited Fast SER messages are still enabled, but the only SER records generated are because of settings changes and power being applied to the relay. If the SER1, SER2, SER3, or SER4 settings are subsequently changed to any non-NA value and SER entries are triggered, unsolicited SER messages will be generated with the new SER records.

02-Function Code: Disable Unsolicited Fast SER Data Transfer, Sent From Master to Relay

This function disables the SEL-651R-2 from transferring unsolicited data. The message format for function code 02 is shown in *Table H.2*.

Table H.2   Function Code 02 Message Format

Data	Description
A546	Message header
10	Message length (16 decimal)
0000000000	Five bytes reserved for future use as a routing address.
YY	Status byte (LSB = 1 indicates an acknowledge is requested)
02	Function code
C0	Sequence byte (Always C0. Other values are reserved for future use in multiple frame messages.)
XX	Response number (XX = 00, 01, 02, 03, 01, 02...)
18	Function to disable (18 = Unsolicited SER)
00	Reserved for future use as function code data
cccc	Two byte CRC-16 check code for message

H.4 | Fast SER Protocol
Functions and Function Codes

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The SEL-651R-2 verifies the message by checking the header, length, function code, and disabled function code against the expected values. It also checks the entire message against the CRC-16 field. If any of the checks fail, except the function code or the function to disable, the message is ignored.

If an acknowledge is requested as indicated by the least significant bit of the status byte, the relay transmits an acknowledge message with the same response number received in the enable message.

If the function to disable is not 18 or the function code is not recognized, the relay responds with an acknowledge message containing response code 01 (function code unrecognized) and no functions are disabled.

18-Function: Unsolicited Fast SER Response, Sent From Relay to Master

The function 18 is used for the transmission of unsolicited Fast Sequential Events Recorder (SER) data from the SEL-651R-2. This function code is also passed as data in the "Enable Unsolicited Data Transfer" and the "Disable Unsolicited Data Transfer" messages to indicate which type of unsolicited data should be enabled or disabled. The message format for function code 18 is shown in *Table H.3*.

Table H.3   Function Code 18 Message Format (Sheet 1 of 2)

Data	Description
A546	Message header
ZZ	Message length (as long as 34 + 4 • *nn* decimal, where *nn* is the maximum number of SER records allowed per message as indicated in the "Enable Unsolicited Data Transfer" message)
0000000000	Five bytes reserved for future use as a routing address
YY	Status Byte (01 = need acknowledgment; 03 = settings changed and need acknowledgment. If YY = 03, the master should re-read the SNS data because the element index list may have changed)
18	Function code
C0	Sequence byte (Always C0. Other values are reserved for future use in multiple frame messages)
XX	Response number (XX = 00, 01, 02, 03, 01, 02...)
00000000	Four bytes reserved for future use as a return routing address
dddd	Two-byte day of year (1–366)
yyyy	Two-byte, four-digit year (e.g., 1999 or 07CF hex)
mmmmmmmm	Four-byte time of day in milliseconds since midnight
XX	1st element index (match with the response to the **SNS** command; 00 for 1st element, 01 for second element, and so on)
uuuuuu	Three-byte time tag offset of 1st element in microseconds since time indicated in the time of day field
XX	2nd element index
uuuuuu	Three-byte time tag offset of 2nd element in microseconds since time indicated in the time of day field
.	
.	
.	
xx	Last element index
uuuuuu	Three-byte time tag offset of last element in microseconds since time indicated in the time of day field

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Table H.3   Function Code 18 Message Format (Sheet 2 of 2)

Data	Description
FFFFFFFE	Four-byte end-of-records flag
ssssssss	Packed four-byte element status for as many as 32 elements (LSB for the 1st element)
cccc	Two-byte CRC-16 check code for message

If the relay determines that SER records have been lost, it sends a message with the following format:

Data	Description
A546	Message header
22	Message length (34 decimal)
0000000000	Five bytes reserved for future use as a routing address.
YY	Status Byte (01 = need acknowledgment; 03 = settings changed and need acknowledgment)
18	Function code
C0	Sequence byte (Always C0. Other values are reserved for future use in multiple frame messages.)
XX	Response number (XX = 00, 01, 02, 03, 00, 01, ...)
00000000	Four bytes reserved for future use as a return routing address.
dddd	Two-byte day of year (1–366) of overflow message generation
yyyy	Two-byte, four-digit year (e.g., 1999 or 07CF hex) of overflow message generation.
mmmmmmmm	Four-byte time of day in milliseconds since midnight
FFFFFFFE	Four-byte end-of-records flag
00000000	Element status (unused)
cccc	Two byte CRC-16 check code for message

Acknowledge Message Sent from Master to Relay, and From Relay to Master

The acknowledge message is constructed and transmitted for every received message that contains a status byte with the LSB set (except another acknowledge message), and which passes all other checks, including the CRC. The acknowledge message format is shown in *Table H.4*.

Table H.4   Acknowledge Message Format

Data	Description
A546	Message header
0E	Message length (14 decimal)
0000000000	Five bytes reserved for future use as a routing address
00	Status byte (always 00)
XX	Function code, echo of acknowledged function code with MSB set
RR	Response code (see below)
XX	Response number (XX = 00, 01, 02, 03, 00, 01, ...) must match response number from message being acknowledged
cccc	Two byte CRC-16 check code for message

H.6 | Fast SER Protocol
Functions and Function Codes

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The SEL-651R-2 supports the following response codes:

Table H.5   SEL-651R-2 Response Codes

RR	Response
00	Success
01	Function code not recognized

Examples

1. Successful acknowledge for "Enable Unsolicited Fast SER Data Transfer" message from a relay with at least one of SER1, SER2, SER3, or SER4 not set to NA:

   A5 46 0E 00 00 00 00 00 00 81 00 XX cccc

   (XX is the same as the Response Number in the "Enable Unsolicited Data Transfer" message to which it responds)

2. Unsuccessful acknowledge for "Enable Unsolicited Fast SER Data Transfer" message from a relay with all of SER1, SER2, SER3, and SER4 set to NA:

   A5 46 0E 00 00 00 00 00 00 81 02 XX cccc

   (XX is the same as the response number in the "Enable Unsolicited Data Transfer" message to which it responds.)

3. Disable Unsolicited Fast SER Data Transfer message, acknowledge requested:

   A5 46 10 00 00 00 00 00 01 02 C0 XX 18 00 cccc

   (XX = 0, 1, 2, 3)

4. Successful acknowledge from the relay for the "Disable Unsolicited Fast SER Data Transfer" message:

   A5 46 0E 00 00 00 00 00 00 82 00 XX cccc

   (XX is the same as the response number in the "Disable Unsolicited Fast SER Data Transfer" message to which it responds.)

5. Successful acknowledge message from the master for an unsolicited Fast SER message:

   A5 46 0E 00 00 00 00 00 00 98 00 XX cccc

   (XX is the same as the response number in the unsolicited Fast SER message to which it responds.)

Notes:

Once the relay receives an acknowledge with response code 00 from the master, it will clear the Settings Changed bit (bit 1) in its status byte if that bit is asserted, and it will clear the Settings Changed bit in fast meter if that bit is asserted.

An element index of FE indicates that the SER record is a result of startup. An element index of FF indicates that the SER record is because of a setting change. An element index of FD indicates that the element identified in this SER record is no longer in the SER trigger settings.

When the relay sends an SER message packet, it will put a sequential number (0, 1, 2, 3, 0, 1, ...) into the response number. If the relay does not receive an acknowledge from the master before approximately 500 ms, the relay will resend the same message packet with the same response number until it

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receives an acknowledge message with that response number. For the next SER message, the relay will increment the response number (it will wrap around to zero from three).

A single Fast SER message packet from the relay can have a maximum of 32 records and the data may span a time period of no more than 16 seconds. The master may limit the number records in a packet with the third byte of function code data in the "Enable Unsolicited Data Transfer" message (function code 01). The relay may generate an SER packet with less than the requested number of records, if the record time stamps span more than 16 seconds.

The relay always requests acknowledgment in unsolicited Fast SER messages (LSB of the status byte is set).

Unsolicited Fast SER messages can be enabled on multiple ports simultaneously.

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Appendix I

Configuration, Fast Meter, and Fast Operate Commands

Overview

SEL relays have two separate data streams that share the same serial port. Data communications with the relay consist of ASCII character commands and reports that are intelligible using a terminal or terminal emulation package. The binary data streams can interrupt the ASCII data stream to obtain information and then allow the ASCII data stream to continue.

This mechanism allows a single communications channel to be used for ASCII communications (e.g., transmission of a long event report) interleaved with short bursts of binary data to support fast acquisition of metering data. The device connected to the other end of the link requires software that uses the separate data streams to exploit this feature. The binary commands and ASCII commands can also be accessed by a device that does not interleave the data streams.

SEL Application Guide AG95-10, *Configuration and Fast Meter Messages*, is a comprehensive description of the SEL binary messages. Below is a description of the messages provided in the SEL-651R-2.

Message Lists

Binary Message List

NOTE: The SEL-651R-2 is not compatible with Fast Meter requests when issued by an SEL-2020, an SEL-2030 with R124 firmware or earlier, or an SEL-2032 with R112 firmware or earlier.

Table I.1   Binary Message List (Sheet 1 of 2)

Request to Relay (hex)	Response From Relay
A5C0	Relay Definition Block
A5C1	Fast Meter Configuration Block
A5D1	Fast Meter Data Block
A5C2	Demand Fast Meter Configuration Block
A5D2	Demand Fast Meter Data Message
A5C3	Peak Demand Fast Meter Configuration Block
A5D3	Peak Demand Fast Meter Data Message
A5B9	Fast Meter Status Acknowledge
A5CE	Fast Operate Configuration Block
A5E0	Fast Operate Remote Bit Control
A5E3	Fast Operate Breaker Control

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Table I.1   Binary Message List (Sheet 2 of 2)

Request to Relay (hex)	Response From Relay
A5CD	Fast Reset Configuration Block
A5ED	Fast Reset Control

ASCII Configuration Message List

Table I.2   ASCII Configuration Message List

Request to Relay (ASCII)	Response From Relay
ID	ASCII Firmware ID String and Terminal ID Setting (TID)
DNA	ASCII Names of Relay Word bits
BNA	ASCII Names of bits in the A5D1 Status Byte
SNS	ASCII Names of bits in the SER trigger settings

Message Definitions

A5C0 Relay Definition Block

In response to the A5C0 request, the relay sends the following block.

Table I.3   A5C0 Relay Definition Block

Data	Description
A5C0	Command
28	Message length
06	Support six protocols: SEL, MIRRORED BITS, DNP, Modbus, IEEE C37.118, and IEC 61850.
03	Support Fast Meter, fast demand, and fast peak
01	Status flag for Settings change
A5C1	Fast Meter configuration
A5D1	Fast Meter message
A5C2	Fast demand configuration
A5D2	Fast demand message
A5C3	Fast peak configuration
A5D3	Fast peak message
0001	Settings change bit
A5C100000000	Reconfigure Fast Meter on settings change
0300	SEL protocol with Fast Operate and fast message (unsolicited SER messaging)
0002	Modbus
0005	DNP3
0006	MIRRORED BITS protocol
0007	IEEE C37.118 Synchrophasors
0008	IEC 61850
00	Reserved
xx	Checksum

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A5C1 Fast Meter Configuration Block

In response to the A5C1 request, the relay sends the following block.

Table I.4   A5C1 Fast Meter Configuration Block (Sheet 1 of 2)

Data	Description
A5C1	Fast Meter command
8E	Length
01	One status flag byte
00	Scale factors in Fast Meter message
00	# of scale factors
0B	# of analog input channels
02	# of samples per channel
88	# of digital banks
01	One calculation block
0004	Analog channel offset
005C	Time stamp offset
0064	Digital offset
494100000000	Analog channel name [IA] (IA)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494200000000	Analog channel name [IB] (IB)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494300000000	Analog channel name [IC] (IC)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494E00000000	Analog channel name [IN] (IN)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
564131000000	Analog channel name [VA1] (VAY)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
564231000000	Analog channel name [VB1] (VBY)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
564331000000	Analog channel name [VC1] (VCY)
01	Analog channel type
FF	Scale factor type

NOTE: Analog channel names are transmitted by the relay as part of the A5C1 message. To support legacy applications, some Fast Meter analog channel names differ from the analog labels used for DNP and Modbus protocols documented in Appendix G: Analog Quantities, Appendix E: DNP3 Communications, and Appendix K: Modbus RTU and TCP Communications. The analog channel names shown in brackets [] in Table I.4 are those contained in the Fast Meter message. The analog labels from Appendix G: Analog Quantities are shown in parentheses.

NOTE: See Appendix G: Analog Quantities for definitions of analog channel names.

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Table I.4   A5C1 Fast Meter Configuration Block (Sheet 2 of 2)

Data	Description
0000	Scale factor offset in Fast Meter message
564132000000	Analog channel name [VA2] (VAZ)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
564232000000	Analog channel name [VB2] (VBZ)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
564332000000	Analog channel name [VC2] (VCZ)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
465245510000	Analog channel name [FREQ] (FREQ)
01	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
00	Line Configuration (00–ABC, 01–ACB)
00	Power Calculations
FFFF	No Deskew angle
FFFF	No Rs compensation (–1)
FFFF	No Xs compensation (–1)
00	**IA** channel index
01	**IB** channel index
02	**IC** channel index
0x	**VA** channel index (x = 7 If EPHANT = VZ OR (EPHANT ≠ VZ AND VSELECT = VZ), else x = 4)
0x	**VB** channel index (x = 8 If EPHANT = VZ OR (EPHANT ≠ VZ AND VSELECT = VZ), else x = 5)
0x	**VC** channel index (x = 9 If EPHANT = VZ OR (EPHANT ≠ VZ AND VSELECT = VZ), else x = 6)
00	Reserved
checksum	1-byte checksum of all preceding bytes

A5D1 Fast Meter Data Block

In response to the A5D1 request, the relay sends the following block.

Table I.5   A5D1 Fast Meter Data Block (Sheet 1 of 2)

Data	Description
A5D1	Command
EE	Length
1 byte	1 Status Byte
88 bytes	X and Y components of: IA, IB, IC, IN, VA1, VB1, VC1, VA2, VB2, VC2, and FREQ in 4-byte IEEE FPS

Table I.5   A5D1 Fast Meter Data Block (Sheet 2 of 2)

Data	Description
8 bytes	Time stamp
136 bytes	136 digital banks: TAR0–TAR135
1 byte	Reserved
checksum	1-byte checksum of all preceding bytes

A5C2/A5C3 Demand/ Peak Demand Fast Meter Configuration Messages

In response to the A5C2 or A5C3 request, the relay sends the following block.

Table I.6   A5C2/A5C3 Demand/Peak Demand Fast Meter Configuration Messages (Sheet 1 of 3)

Data	Description
A5C2 or A5C3	Command; Demand (A5C2) or Peak Demand (A5C3)
EE	Length
01	# of status flag bytes
00	Scale factors in meter message
00	# of scale factors
16	# of analog input channels
01	# of samples per channel
00	# of digital banks
00	# of calculation blocks
0004	Analog channel offset
00B4	Time stamp offset
FFFF	Digital offset
494100000000	Analog channel name [IA] (IADEM or IAPK)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494200000000	Analog channel name [IB] (IBDEM or IBPK)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494300000000	Analog channel name [IC] (ICDEM or ICPK)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494E00000000	Analog channel name [IN] (INDEM or INPK)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
494700000000	Analog channel name [IG] (IGDEM or IGPK)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message

NOTE: Analog channel names are transmitted by the relay as part of the A5C2 and A5C3 messages. To support legacy applications, some Fast Meter analog channel names differ from the analog labels used for DNP and Modbus protocols documented in Appendix G: Analog Quantities, Appendix E: DNP3 Communications, and Appendix K: Modbus RTU and TCP Communications. The analog channel names shown in brackets [] in Table I.6 are those contained in the Fast Meter message. The analog labels from Appendix G: Analog Quantities are shown in parentheses.

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Table I.6   A5C2/A5C3 Demand/Peak Demand Fast Meter Configuration Messages (Sheet 2 of 3)

Data	Description
334932000000	Analog channel name [3I2] (3I2DEM or 3I2PK)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
504131000000	Analog channel name [PA1] (MWADO or MWAPO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
504231000000	Analog channel name [PB1] (MWBDO or MWBPO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
504331000000	Analog channel name [PC1] (MWCDO or MWCPO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
503100000000	Analog channel name [P1] (MW3DO or MW3PO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
514131000000	Analog channel name [QA1] (MVRADO or MVRAPO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
514231000000	Analog channel name [QB1] (MVRBDO or MVRBPO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
514331000000	Analog channel name [QC1] (MVRCDO or MVRCPO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
513100000000	Analog channel name [Q1] (MVR3DO or MVR3PO)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
504132000000	Analog channel name [PA2] (MWADI or MWAPI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message

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Table I.6   A5C2/A5C3 Demand/Peak Demand Fast Meter Configuration Messages (Sheet 3 of 3)

Data	Description
504232000000	Analog channel name [PB2] (MWBDI or MWBPI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
504332000000	Analog channel name [PC2] (MWCDI or MWCPI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
503200000000	Analog channel name [P2] (MW3DI or MW3PI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
514132000000	Analog channel name [QA2] (MVRADI or MVRAPI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
514232000000	Analog channel name [QB2] (MVRBDI or MVRBPI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
514332000000	Analog channel name [QC2] (MVRCDI or MVRCPI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
513200000000	Analog channel name [Q2] (MVR3DI or MVR3PI)
02	Analog channel type
FF	Scale factor type
0000	Scale factor offset in Fast Meter message
00	Reserved
checksum	1-byte checksum of preceding bytes

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A5D2/A5D3 Demand/ Peak Demand Fast Meter Message

In response to the A5D2 or A5D3 request, the relay sends the following block.

Table I.7   A5D2/A5D3 Demand/Peak Demand Fast Meter Message

Data	Description
A5D2 or A5D3	Command
BE	Length
1 byte	1 Status Byte
176-bytes	IADEM/IAPK, IBDEM/IBPK, ICDEM/ICPK, INDEM/INPK, IGDEM/IGPK, 3I2DEM/3I2PK, MWADI/MWAPI, MWBDI/MWBPI, MWCDI/MWCPI, MW3DI/MW3PI, MVRADI/MVRAPI, MVRBDI/MVRBPI, MVRCDI/MVRCPI, MVR3DI/MVR3PI, MWADO/MWAPO, MWBDO/MWBPO, MWCDO/MWCPO, MW3DO/MW3PO, MVRADO/MVRAPO, MVRBDO/MVRBPO, MVRCDO/MVRCPO, MVR3DO/MVR3PO in 8-byte IEEE FPS
8 bytes	Time stamp
1 byte	Reserved
1 byte	1-byte checksum of all preceding bytes

A5B9 Fast Meter Status Acknowledge Message

In response to the A5B9 request, the relay clears the Fast Meter (message A5D1) Status Byte. The SEL-651R-2 Status Byte contains two active bits: STSET (bit 1) and PWRUP (bit 2); both bits are set on startup. The STSET bit is also set on settings changes. If the STSET bit is set, the external device should request the A5C1, A5C2, and A5C3 messages. The external device can then determine if the scale factors or line configuration parameters have been modified.

A5CE Fast Operate Configuration Block

In response to the A5CE request, the relay sends the following block.

Table I.8   A5CE Fast Operate Configuration Block (Sheet 1 of 4)

Data	Description
A5CE	Command
72	Length
04	Support 3 circuit breakers with individual phase operation
0020	Support 32 remote bit set/clear commands
0100	Allow remote bit pulse commands
31	Operate code, open breakers 1, 2 and 3
11	Operate code, close breakers 1, 2 and 3
32	Operate code, open breaker 1
12	Operate code, close breaker 1
33	Operate code, open breaker 2
13	Operate code, close breaker 2
34	Operate code, open breaker 3
14	Operate code, close breaker 3
00	Operate code, clear remote bit RB01
20	Operate code, set remote bit RB01
40	Operate code, pulse remote bit RB01
01	Operate code, clear remote bit RB02

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Table I.8 A5CE Fast Operate Configuration Block (Sheet 2 of 4)

Data	Description
21	Operate code, set remote bit RB02
41	Operate code, pulse remote bit RB02
02	Operate code, clear remote bit RB03
22	Operate code, set remote bit RB03
42	Operate code, pulse remote bit RB03
03	Operate code, clear remote bit RB04
23	Operate code, set remote bit RB04
43	Operate code, pulse remote bit RB04
04	Operate code, clear remote bit RB05
24	Operate code, set remote bit RB05
44	Operate code, pulse remote bit RB05
05	Operate code, clear remote bit RB06
25	Operate code, set remote bit RB06
45	Operate code, pulse remote bit RB06
06	Operate code, clear remote bit RB07
26	Operate code, set remote bit RB07
46	Operate code, pulse remote bit RB07
07	Operate code, clear remote bit RB08
27	Operate code, set remote bit RB08
47	Operate code, pulse remote bit RB08
08	Operate code, clear remote bit RB09
28	Operate code, set remote bit RB09
48	Operate code, pulse remote bit RB09
09	Operate code, clear remote bit RB10
29	Operate code, set remote bit RB10
49	Operate code, pulse remote bit RB10
0A	Operate code, clear remote bit RB11
2A	Operate code, set remote bit RB11
4A	Operate code, pulse remote bit RB11
0B	Operate code, clear remote bit RB12
2B	Operate code, set remote bit RB12
4B	Operate code, pulse remote bit RB12
0C	Operate code, clear remote bit RB13
2C	Operate code, set remote bit RB13
4C	Operate code, pulse remote bit RB13
0D	Operate code, clear remote bit RB14
2D	Operate code, set remote bit RB14
4D	Operate code, pulse remote bit RB14
0E	Operate code, clear remote bit RB15
2E	Operate code, set remote bit RB15
4E	Operate code, pulse remote bit RB15

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Table I.8 A5CE Fast Operate Configuration Block (Sheet 3 of 4)

Data	Description
0F	Operate code, clear remote bit RB16
2F	Operate code, set remote bit RB16
4F	Operate code, pulse remote bit RB16
10	Operate code, clear remote bit RB17
30	Operate code, set remote bit RB17
50	Operate code, pulse remote bit RB17
11	Operate code, clear remote bit RB18
31	Operate code, set remote bit RB18
51	Operate code, pulse remote bit RB18
12	Operate code, clear remote bit RB19
32	Operate code, set remote bit RB19
52	Operate code, pulse remote bit RB19
13	Operate code, clear remote bit RB20
33	Operate code, set remote bit RB20
53	Operate code, pulse remote bit RB20
14	Operate code, clear remote bit RB21
34	Operate code, set remote bit RB21
54	Operate code, pulse remote bit RB21
15	Operate code, clear remote bit RB22
35	Operate code, set remote bit RB22
55	Operate code, pulse remote bit RB22
16	Operate code, clear remote bit RB23
36	Operate code, set remote bit RB23
56	Operate code, pulse remote bit RB23
17	Operate code, clear remote bit RB24
37	Operate code, set remote bit RB24
57	Operate code, pulse remote bit RB24
18	Operate code, clear remote bit RB25
38	Operate code, set remote bit RB25
58	Operate code, pulse remote bit RB25
19	Operate code, clear remote bit RB26
39	Operate code, set remote bit RB26
59	Operate code, pulse remote bit RB26
1A	Operate code, clear remote bit RB27
3A	Operate code, set remote bit RB27
5A	Operate code, pulse remote bit RB27
1B	Operate code, clear remote bit RB28
3B	Operate code, set remote bit RB28
5B	Operate code, pulse remote bit RB28
1C	Operate code, clear remote bit RB29
3C	Operate code, set remote bit RB29

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Table I.8   A5CE Fast Operate Configuration Block (Sheet 4 of 4)

Data	Description
5C	Operate code, pulse remote bit RB29
1D	Operate code, clear remote bit RB30
3D	Operate code, set remote bit RB30
5D	Operate code, pulse remote bit RB30
1E	Operate code, clear remote bit RB31
3E	Operate code, set remote bit RB31
5E	Operate code, pulse remote bit RB31
1F	Operate code, clear remote bit RB32
3F	Operate code, set remote bit RB32
5F	Operate code, pulse remote bit RB32
00	Reserved
checksum	1-byte checksum of all preceding bytes

A5E0 Fast Operate Remote Bit Control

The external device sends the following message to perform a remote bit operation.

Table I.9   A5E0 Fast Operate Remote Bit Control

Data	Description
A5E0	Command
06	Length
1 byte	Operate code: 00–1F clear remote bit RB01–RB32 20–3F set remote bit RB01–RB32 40–5F pulse remote bit for RB01–RB32 for one processing interval
1 byte	Operate validation: 4 • Operate code + 1
checksum	1-byte checksum of preceding bytes

The relay performs the specified remote bit operation if the following conditions are true:

➤ The Operate code is valid.

➤ The Operate validation = 4 • Operate code + 1.

➤ The message checksum is valid.

➤ The FASTOP port setting is set to Y.

➤ The relay is enabled.

Remote bit set and clear operations are latched by the relay. Remote bit pulse operations assert the remote bit for one processing interval (1/4 cycle).

It is common practice to route remote bits to output contacts to provide remote control of the relay outputs. If you wish to pulse an output contact closed for a specific duration, SEL recommends using the remote bit pulse command and SELOGIC control equations to provide secure and accurate contact control. The remote device sends the remote bit pulse command; the relay controls the timing of the output contact assertion. You can use any remote bit (RB01–RB32) and any SELOGIC control equation timer (SV01–SV64) to control any

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of the output contacts. For example, to pulse output contact **OUT104** for 30 cycles with Remote Bit RB04 and SELOGIC control equation timer SV04, issue the following relay settings:

Via the **SET L** command:

ESV := **4** enable 4 SELOGIC control equations

SV04PU := **0** SV04 pickup time = 0

SV04DO := **30** SV04 dropout time is 30 cycles

SV4 := **RB04** SV04 input is RB04

OUT104 := **SV04T** route SV04 timer output to **OUT104**

To pulse the contact, send the **A5E006430DDB** command to the relay.

A5E3 Fast Operate Breaker Control

The external device sends the following message to perform a fast breaker open/close.

Table I.10   A5E3 Fast Operate Breaker Control

Data	Description
A5E3	Command
06	Length
1 byte	Operate code: 31—OPEN Breakers 1, 2, and 3 11—CLOSE Breakers 1, 2, and 3 32—OPEN Breaker 1 12—CLOSE Breaker 1 33—OPEN Breaker 2 13—CLOSE Breaker 2 34—OPEN Breaker 3 14—CLOSE Breaker 3
1 byte	Operate Validation: $4 \cdot$ Operate code $+ 1$
Checksum	1-byte checksum of preceding bytes

The relay performs the specified breaker operation if the following conditions are true:

➤ Conditions defined in the A5E0 message are true.

➤ The breaker jumper (JMP2B) is in place on the SEL-651R-2 main board.

A5CD Fast Operate Reset Definition Block

In response to an A5CD request, the relay sends the configuration block for the Fast Operate Reset message.

Table I.11   A5CD Fast Operate Reset Definition Block

Data	Description
A5CD	Command
0E	Message length
01	The number of Fast Operate reset codes supported
00	Reserved for future use
00	Fast Operate reset code ("00" for target reset)
54415220520D00	Fast Operate reset description string ("TAR R")
xx	Checksum

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A5ED Fast Operate Reset Command

The Fast Operate Reset commands take the following form.

Table I.12 A5ED Fast Operate Reset Command

Data	Description
A5ED	Command
06	Message Length—always 6
00	Operate Code ("00" for target reset, "TAR R")
01	Operate Validation—(4 • Operate Code) + 1
xx	Checksum

ID Message

In response to the **ID** command, the relay sends the firmware ID (FID), boot firmware ID (BFID), firmware checksum (CID), relay TID setting (DEVID), Modbus device code (DEVCODE)—for use by an SEL Communications Processor, relay part number (PARTNO), relay serial number (SERIALNO), and configuration string (CONFIG)—for use by other IEDs or software.

A sample response is shown below; responses will differ depending on relay, settings, and firmware.

```
<STX>
"FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","yyyy"<CR><LF>
"BFID=SLBT-3CF1-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","yyyy"<CR><LF>
"CID=xxxx","yyyy"<CR><LF>
"DEVID=STATION A","yyyy"<CR><LF>
"DEVCODE=56","yyyy"<CR><LF>
"PARTNO=0651R261XAA83A1113XXXX","yyyy"<CR><LF>
"SERIALNO=000000000000000","yyyy"<CR><LF>
"CONFIG=1124200","yyyy"<CR><LF>
"SPECIAL=01211","yyyy"<CR><LF>
"iedName=","0360"<CR><LF>
"type=","026F"<CR><LF>
"configVersion=","0609"<CR><LF>
<ETX>
```

where:

<STX>	is the STX character (02)
<ETX>	is the ETX character (03)
xxxx	is the 4-byte ASCII hex representation of the checksum of the relay firmware
yyyy	is the 4-byte ASCII hex representation of the checksum for each line

The ID message is available from Access Level 0 and higher.

DNA Message

In response to the **DNA T** or **DNA X** command, the relay sends names of the Relay Word bits transmitted in the A5D1 message. The first name is associated with the MSB, the last name with the LSB. These names are listed in the Relay Word in *Appendix F: Relay Word Bits*. The **DNA** command is available from Access Level 0 and higher.

In response to the **DNA** command (without T or X modifier), the relay sends the **DNA X** command with all Relay Word bit names replaced with *. This is necessary for compatibility with older communications processors.

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An example DNA T message for the SEL-651R-2 is shown below.

```
"EN","TRIPLED","*","*","*","*","*","*","0723"<CR><LF>
"TLED_08","TLED_07","TLED_06","TLED_05","TLED_04","TLED_03","TLED_02","TLED_01","12E4"<CR><LF>
"TLED_16","TLED_15","TLED_14","TLED_13","TLED_12","TLED_11","TLED_10","TLED_09","12E5"<CR><LF>
"TLED_24","TLED_23","TLED_22","TLED_21","TLED_20","TLED_19","TLED_18","TLED_17","12EF"<CR><LF>
"50A1","50B1","50C1","50P1","50A2","50B2","50C2","50P2","0A60"<CR><LF>
"50A3","50B3","50C3","50P3","50A4","50B4","50C4","50P4","0A70"<CR><LF>
"50G1","50G2","50G3","50G4","50Q1","50Q2","50Q3","50Q4","0A9C"<CR><LF>
"50N1","50N2","50N3","50N4","50A","50B","50C","50P32","0A25"<CR><LF>
"50P5","50P6","50G5","50G6","50Q5","50Q6","50N5","50N6","0AC0"<CR><LF>
"50LA","50LB","50LC","50L","50GF","50GR","50QF","50QR","0AFE"<CR><LF>
"51AS","51AR","51A","51AT","51BS","51BR","51B","51BT","0AAE"<CR><LF>
"51CS","51CR","51C","51CT","51PS","51PR","51P","51PT","0AEE"<CR><LF>
"51G1S","51G1R","51G1","51G1T","51G2S","51G2R","51G2","51G2T","0C66"<CR><LF>
"51QS","51QR","51Q","51QT","*","*","*","*","07FD"<CR><LF>
"50A1T","50B1T","50C1T","50P1T","50A2T","50B2T","50C2T","50P2T","0D00"<CR><LF>
"50A3T","50B3T","50C3T","50P3T","50A4T","50B4T","50C4T","50P4T","0D10"<CR><LF>
"50G1T","50G2T","50G3T","50G4T","50Q1T","50Q2T","50Q3T","50Q4T","0D3C"<CR><LF>
"50N1T","50N2T","50N3T","50N4T","*","*","*","*","090E"<CR><LF>
"52AA","52AB","52AC","52A3P","SPOA","SPOB","SPOC","SPO","0BF7"<CR><LF>
"V1GOOD","LOP","VPOLV","GNDSW","DD","SPE","SW1","3PO","0C52"<CR><LF>
"FSA","FSB","FSC","*","PHASE_A","PHASE_B","PHASE_C","*","0C9B"<CR><LF>
"ZLOUT","ZLIN","ZLOAD","*","FAULT","*","*","*","09F9"<CR><LF>
"27YA1","27YB1","27YC1","27YA2","27YB2","27YC2","59YA1","59YB1","0D34"<CR><LF>
"59YC1","59YA2","59YB2","59YC2","27YAB1","27YBC1","27YCA1","59YAB1","0E4C"<CR><LF>
"59YBC1","59YCA1","59YN1","59YN2","59YQ1","59YV1","3P27Y","3P59Y","0E2C"<CR><LF>
"*","*","*","*","*","*","*","VSELY","0639"<CR><LF>
"27ZA1","27ZB1","27ZC1","27ZA2","27ZB2","27ZC2","59ZA1","59ZB1","0D3C"<CR><LF>
"59ZC1","59ZA2","59ZB2","59ZC2","27ZAB1","27ZBC1","27ZCA1","59ZAB1","0E54"<CR><LF>
"59ZBC1","59ZCA1","59ZN1","59ZN2","59ZQ1","59ZV1","3P27Z","3P59Z","0E34"<CR><LF>
"*","*","*","*","*","*","*","VSELZ","063A"<CR><LF>
"SF","25A1","25A2","SFAST","SSLOW","*","59VS","59VP","0B3A"<CR><LF>
"81D1","81D2","81D3","81D4","81D5","81D6","FREQOK","*","0AB5"<CR><LF>
"81D1T","81D2T","81D3T","81D4T","81D5T","81D6T","27B81","*","0BF9"<CR><LF>
"*","IN107","IN106","IN105","IN104","IN103","IN102","IN101","0BDE"<CR><LF>
"*","*","IN206","IN205","IN204","IN203","IN202","IN201","0ADF"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","PB06_LED","PB05_LED","PB04_LED","PB03_LED","PB02_LED","PB01_LED","10CD"<CR><LF>
"*","*","PB12_LED","PB11_LED","PB10_LED","PB09_LED","PB08_LED","PB07_LED","10D6"<CR><LF>
"PWR_SRC1","*","DISTST","CHRGG","DISCHG","DTFAIL","BTFAIL","TOSLP","0E5A"<CR><LF>
"*","TCCAP","XS_TRIP1","XS_TRIP2","XS_TRIP3","XS_CLOS1","XS_CLOS2","XS_CLOS3","13CD"<CR><LF>
"LB01","LB02","LB03","LB04","LB05","LB06","LB07","LB08","0B14"<CR><LF>
"LB09","LB10","LB11","LB12","LB13","LB14","LB15","LB16","0B15"<CR><LF>
"CCA","CCB","CCC","CC3","OCA","OCB","OCC","OC3","09D2"<CR><LF>
"SOTFE","SOTFT","TRGTR","*","TRIPA","TRIPB","TRIPC","TRIP3P","0E93"<CR><LF>
"LT01","LT02","LT03","LT04","LT05","LT06","LT07","LT08","0BA4"<CR><LF>
"LT09","LT10","LT11","LT12","LT13","LT14","LT15","LT16","0BA5"<CR><LF>
"LT17","LT18","LT19","LT20","LT21","LT22","LT23","LT24","0BAF"<CR><LF>
"LT25","LT26","LT27","LT28","LT29","LT30","LT31","LT32","0BB9"<CR><LF>
"SV01","SV02","SV03","SV04","SV01T","SV02T","SV03T","SV04T","0D2C"<CR><LF>
"SV05","SV06","SV07","SV08","SV05T","SV06T","SV07T","SV08T","0D4C"<CR><LF>
"SV09","SV10","SV11","SV12","SV09T","SV10T","SV11T","SV12T","0D36"<CR><LF>
"SV13","SV14","SV15","SV16","SV13T","SV14T","SV15T","SV16T","0D44"<CR><LF>
"SV17","SV18","SV19","SV20","SV17T","SV18T","SV19T","SV20T","0D52"<CR><LF>
"SV21","SV22","SV23","SV24","SV21T","SV22T","SV23T","SV24T","0D3C"<CR><LF>
"SV25","SV26","SV27","SV28","SV25T","SV26T","SV27T","SV28T","0D5C"<CR><LF>
"SV29","SV30","SV31","SV32","SV29T","SV30T","SV31T","SV32T","0D46"<CR><LF>
"SV33","SV34","SV35","SV36","SV33T","SV34T","SV35T","SV36T","0D54"<CR><LF>
"SV37","SV38","SV39","SV40","SV37T","SV38T","SV39T","SV40T","0D62"<CR><LF>
"SV41","SV42","SV43","SV44","SV41T","SV42T","SV43T","SV44T","0D4C"<CR><LF>
"SV45","SV46","SV47","SV48","SV45T","SV46T","SV47T","SV48T","0D6C"<CR><LF>
"SC01QU","SC02QU","SC03QU","SC04QU","SC05QU","SC06QU","SC07QU","SC08QU","1084"<CR><LF>
"SC01QD","SC02QD","SC03QD","SC04QD","SC05QD","SC06QD","SC07QD","SC08QD","0FFC"<CR><LF>
"SC09QU","SC10QU","SC11QU","SC12QU","SC13QU","SC14QU","SC15QU","SC16QU","1085"<CR><LF>
"SC09QD","SC10QD","SC11QD","SC12QD","SC13QD","SC14QD","SC15QD","SC16QD","0FFD"<CR><LF>
"79RS3P","79CY3P","79LO3P","SHO3P","SH13P","SH23P","SH33P","SH43P","0EC5"<CR><LF>
"79RSA","79CYA","79LOA","SHOA","SH1A","SH2A","SH3A","SH4A","0CB5"<CR><LF>
"79RSB","79CYB","79LOB","SHOB","SH1B","SH2B","SH3B","SH4B","0CBD"<CR><LF>
"79RSC","79CYC","79LOC","SHOC","SH1C","SH2C","SH3C","SH4C","0CC5"<CR><LF>
"CLOSEA","CLOSEB","CLOSEC","CLOSE3P","CFA","CFB","CFC","CF3P","0E0E"<CR><LF>
"RCSFA","RCSFB","RCSFC","RCSF3P","OPTMNA","OPTMNB","OPTMNC","OPTMN3P","1102"<CR><LF>
"RSTMNA","RSTMNB","RSTMNC","RSTMN3P","ULCLA","ULCLB","ULCLC","ULCL3P","1122"<CR><LF>
"32QE","32QGE","32VE","*","F32Q","R32Q","F32QG","R32QG","0B7D"<CR><LF>
"F32V","R32V","F32P","R32P","*","*","*","*","0838"<CR><LF>
"32QF","32QR","32GF","32GR","32PF","32PR","*","*","09CA"<CR><LF>
"BCWA","BCWB","BCWC","BCW","PDEM","NDEM","GDEM","QDEM","0C44"<CR><LF>
"OUT108","OUT107","OUT106","OUT105","OUT104","OUT103","OUT102","OUT101","0FEC"<CR><LF>
"OUT202","OUT201","RCCL3X","RCTR3X","RCCL2X","RCTR2X","RCCL1X","RCTR1X","10F0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"SG1","SG2","SG3","SG4","SG5","SG6","SG7","SG8","09F4"<CR><LF>
"*","*","*","IRIGOK","INMET","ICMET","IBMET","IAMET","0B93"<CR><LF>
"RMB8A","RMB7A","RMB6A","RMB5A","RMB4A","RMB3A","RMB2A","RMB1A","0E34"<CR><LF>
"TMB8A","TMB7A","TMB6A","TMB5A","TMB4A","TMB3A","TMB2A","TMB1A","0E44"<CR><LF>
"RMB8B","RMB7B","RMB6B","RMB5B","RMB4B","RMB3B","RMB2B","RMB1B","0E3C"<CR><LF>
```

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```
"TMB8B","TMB7B","TMB6B","TMB5B","TMB4B","TMB3B","TMB2B","TMB1B","0E4C"<CR><LF>
"LB0KA","CBADA","RBADA","ROKA","LB0KB","CBADB","RBADB","ROKB","0DFA"<CR><LF>
"SAGA","SAGB","SAGC","SAG3P","SWA","SWB","SWC","SW3P","0C26"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"INTA","INTB","INTC","INT3P","*","*","*","TESTDB","0AB9"<CR><LF>
"*","*","*","3PWR1","*","*","*","3PWR2","0737"<CR><LF>
"*","*","*","3PWR3","*","*","*","3PWR4","073B"<CR><LF>
"*","*","PB06","PB05","PB04","PB03","PB02","PB01","0995"<CR><LF>
"*","*","PB06_PUL","PB05_PUL","PB04_PUL","PB03_PUL","PB02_PUL","PB01_PUL","1175"<CR><LF>
"*","*","PB12","PB11","PB10","PB09","PB08","PB07","099E"<CR><LF>
"*","*","PB12_PUL","PB11_PUL","PB10_PUL","PB09_PUL","PB08_PUL","PB07_PUL","117E"<CR><LF>
"RB01","RB02","RB03","RB04","RB05","RB06","RB07","RB08","0B44"<CR><LF>
"RB09","RB10","RB11","RB12","RB13","RB14","RB15","RB16","0B45"<CR><LF>
"RB17","RB18","RB19","RB20","RB21","RB22","RB23","RB24","0B4F"<CR><LF>
"RB25","RB26","RB27","RB28","RB29","RB30","RB31","RB32","0B59"<CR><LF>
"RSTTRGT","RST_MML","RST_ENE","RST_HIS","RST_BK","RST_PDM","RST_DEM","RST_HAL","14DD"<CR><LF>
"*","LINK5A","LINK5B","LNKFAIL","P5ASEL","P5BSEL","TSNTPP","TSNTPB","100D"<CR><LF>
"SV49","SV50","SV51","SV52","SV49T","SV50T","SV51T","SV52T","0D56"<CR><LF>
"SV53","SV54","SV55","SV56","SV53T","SV54T","SV55T","SV56T","0D64"<CR><LF>
"SV57","SV58","SV59","SV60","SV57T","SV58T","SV59T","SV60T","0D72"<CR><LF>
"SV61","SV62","SV63","SV64","SV61T","SV62T","SV63T","SV64T","0D5C"<CR><LF>
"DST","DSTP","LPSEC","LPSECP","TQUAL4","TQUAL3","TQUAL2","TQUAL1","0FCA"<CR><LF>
"TSOK","TIRIG","PMDOK","PMTRIG","TREA4","TREA3","TREA2","TREA1","0F08"<CR><LF>
"SALARM","ACCESS","*","*","HALARMA","HALARMP","HALARML","HALARM","0EF7"<CR><LF>
"*","*","PASNVAL","ACCESSP","GRPSW","SETCHG","CHGPASS","BADPASS","0F43"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"HBL2AT","HBL2BT","HBL2CT","HBL2T","*","*","*","*","0A5E"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>
"*","*","*","*","*","*","*","*","04D0"<CR><LF>

=
```

where:

                                                                                           <STX> is the STX character (02)

                                  <ETX> is the ETX character (03)

the last field in each line (yyyy) is the 4-byte ASCII hex representation of the checksum for the line

            "*" indicates an unused bit location

Messages for other relay models may be derived from the appropriate tables in *Appendix F: Relay Word Bits* of this manual, using the above format.

I.16 Configuration, Fast Meter, and Fast Operate Commands
Message Definitions

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BNA Message

In response to the **BNA** command, the relay sends names of the bits transmitted in the Status Byte in the A5D1 message. The first name is the MSB, the last name is the LSB. The BNA message is:

```
<STX>"*","*","*","*","*","PWRUP","STSET","*","yyyy"<CR><LF><ETX>
```

where:

yyyy   is the 4-byte ASCII representation of the checksum

"*"   indicates an unused bit location

The **BNA** command is available from Access Level 0 and higher.

SNS Message

In response to the **SNS** command, the relay sends the name string of the SER (SER1 SER2 SER3 SER4) settings. The **SNS** command is available at Access Level 1.

The relay responds to the **SNS** command with the name string in the SER settings. The name string starts with SER1, followed by SER2, SER3, and SER4.

For example, if

SER1 := 50A1 OUT101

SER2 := 50P1T 81D1T

SER3 := OUT102 52A3P

SER4 := TRIP3P OUT103

The name string will be

"50A1","OUT101","50P1T","81D1T","OUT102","52A3P","TRIP3P"," OUT103".

If there are more than eight settings in SER, the SNS message will have several rows. Each row will have eight strings, followed by the checksum and carriage return. The last row may have fewer than eight strings.

The SNS message for the SEL-651R-2 is shown below:

```
<STX>
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","yyyy"<CR><LF>
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","yyyy"<CR><LF>
"xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","xxxx","yyyy"<CR><LF>
"xxxx","yyyy"<CR><LF><ETX>
```

where:

xxxx   is a string from the settings in SER (SER1, SER2, SER3, and SER4)

yyyy   is the 4-byte ASCII representation of the checksum

Appendix J

Synchrophasors

Overview

The SEL-651R-2 provides phasor measurement unit (PMU) capabilities when connected to a suitable IRIG-B time source. Synchrophasor is used as a general term that can refer to data or protocol.

This section covers the following topics:

➤ *Introduction on page J.1*

➤ *Synchrophasor Measurement on page J.2*

➤ *Settings for IEEE C37.118 Protocol Synchrophasors on page J.4*

➤ *C37.118 Synchrophasor Protocol on page J.13*

➤ *Synchrophasor Relay Word Bits on page J.16*

➤ *View Synchrophasors by Using the MET PM Command on page J.17*

➤ *Configuring High-Accuracy Timekeeping on page J.21*

See *IRIG-B on page J.21* for the requirements of the IRIG-B time source. Synchrophasors are still measured if the high-accuracy time source is not connected, but the data are not time-synchronized to any external reference, as indicated by Relay Word bit TSOK = logical 0.

Introduction

The word synchrophasor is derived from two words: synchronized and phasor. Synchrophasor measurement refers to the concept of providing measurements taken on a synchronized schedule in multiple locations. A high-accuracy clock, commonly a global positioning system (GPS) receiver such as the SEL-2407 Satellite-Synchronized Clock, makes synchrophasor measurement possible.

The availability of an accurate time reference over a large geographic area allows multiple devices, such as a number of SEL-651R-2 recloser controls, to synchronize the gathering of power system data. The accurate clock allows precise event report triggering and other offline analysis functions.

The SEL-651R-2 Global settings contain the synchrophasor settings, including the choice of the synchrophasor data set the relay will transmit. The Port settings select which serial port(s) are reserved for synchrophasor protocol use and enables synchrophasors on Ethernet ports (see *Settings for IEEE C37.118 Protocol Synchrophasors on page J.4*).

J.2 | Synchrophasors
Synchrophasor Measurement

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The SEL-651R-2 generates time status Relay Word bits and time-quality information that is important for synchrophasor measurement. Some protection SELOGIC control equation variables and programmable digital trigger information are also added to the Relay Word bits for synchrophasors (see *Synchrophasor Relay Word Bits on page J.16*).

The value of synchrophasor data increases greatly when the data can be shared over a communications network in real time. IEEE C37.118 synchrophasor protocol is available in the SEL-651R-2, which allows for a centralized device to collect data efficiently from several phasor measurement units (PMUs). Some possible uses of a system-wide synchrophasor system include the following:

➤ Power system state measurement

➤ Wide-area network protection and control schemes

➤ Small signal analysis

➤ Power system disturbance analysis

IEEE C37.118 compliant synchrophasor data are available on multiple serial ports when the port setting PROTO := PMU and on Ethernet Ports when port setting EPMIP := Y.

You can view synchrophasor data over a serial port set to PROTO = SEL, see *View Synchrophasors by Using the MET PM Command on page J.17*.

Synchrophasor Measurement

NOTE: The synchrophasor data stream is separate from the other protection and metering functions.

The phasor measurement unit in the SEL-651R-2 measures six voltages and four currents on a constant time basis. These samples are synchronized to the high-accuracy IRIG-B time source and occur at a fixed frequency of either 60 Hz or 50 Hz, depending on Global setting NFREQ. The relay then filters the measured samples according to Global setting PMAPP = F or N (see *PMAPP on page J.6*). The phase angle is measured relative to an absolute reference, which is represented by a cosine function in *Figure J.1*. The time of day is shown for the two time marks.

10:00:00.000000   10:00:00.016667
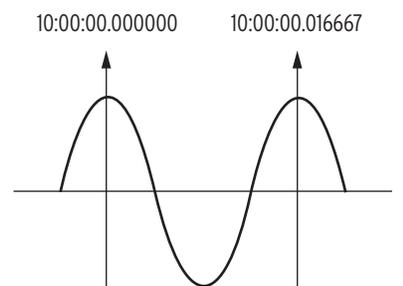
Figure J.1   High-Accuracy Clock Controls Reference Signal (60 Hz System)

NOTE: For SEL-651R-2 models with LEA inputs, the VnYPAC and VnZPAC settings (where n = 1, 2, or 3) are used to compensate for phase angle shifts in the measurement path (see Voltage Phase Angle Correction Settings for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.36). In this case, the VYCOMP and VZCOMP settings do not need to be used to compensate for such phase angle shifts.

The instrument transformers (PTs or CTs) and the interconnecting cables may introduce a time shift in the measured signal. Global settings VYCOMP, VZCOMP, IPCOMP, and INCOMP, entered in degrees, are added to the measured phasor angles to create the corrected phasor angles, as shown in *Figure J.2*. The VYCOMP, VZCOMP, IPCOMP, and INCOMP settings may be positive or negative values. The corrected angles are displayed in the **MET PM** command and transmitted as part of synchrophasor messages.
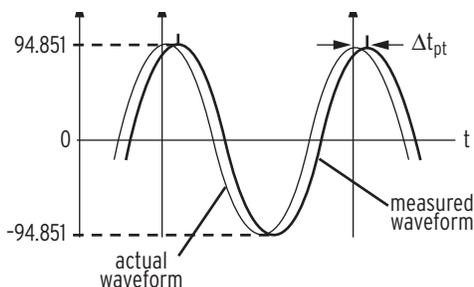
Figure J.2   Waveform at Relay Terminals May Have Phase Shift

$$\text{Compensation Angle} = \frac{\Delta t_{pt}}{\left(\dfrac{1}{\text{freq}}\right)} \bullet 360°$$

$$= \Delta t_{pt} \bullet \text{freq} \bullet 360°$$

Equation J.1

If the time shift on the pt measurement path $\Delta t_{pt} = 0.784$ ms and the nominal frequency, $\text{freq}_{nominal} = 60 \text{Hz}$, use *Equation J.2* to obtain the correction angle:

$$0.784 \bullet 10^{-3} \text{s} \bullet 60 \text{s}^{-1} \bullet 360° = 16.934°$$

Equation J.2
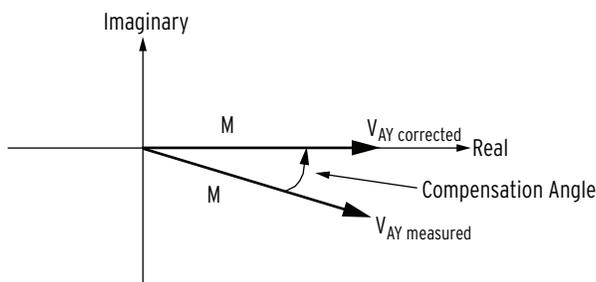
Figure J.3   Correction of Measured Phase Angle

For a sinusoidal signal, the phasor magnitude is calculated as shown in *Equation J.3*. The phasors are rms values scaled in primary units, as determined by Group settings PTRY, PTRZ, CTR, and CTRN. The SEL-651R-2 then calculates the positive-sequence voltage and currents.

$$\text{Magnitude M} = \frac{V_{pk}}{\sqrt{2}} \bullet \text{PTR}_{setting}$$

Equation J.3

With PTRY = 2000 and the signal in *Figure J.2* (with peak voltage $V_{pk} = 94.851$ V), use *Equation J.4* to obtain the magnitude, VAY_MAG:

$$VAY\_MAG = \frac{94.851}{\sqrt{2}} \bullet 2000$$

$$= 134140 \text{ V}$$

$$= 134.140 \text{ kV}$$

Equation J.4

Finally, the magnitude and angle pair for each synchrophasor is converted to a real and imaginary pair by using *Equation J.5* and *Equation J.6*. For example, analog quantities VAY_MAG and VAY_ANG are converted to VAY_REAL and VAY_IMG. An example phasor with an angle measurement of 104.400° is shown in *Figure J.4*.

J.4 Synchrophasors
Settings for IEEE C37.118 Protocol Synchrophasors

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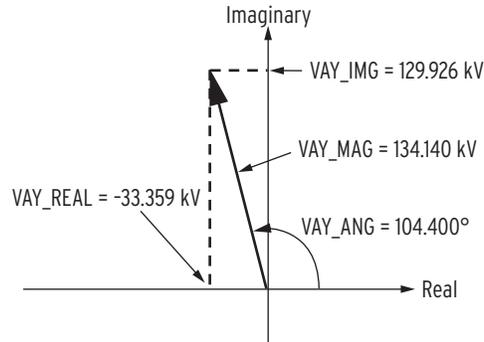
Figure J.4   Example Calculation of Real and Imaginary Components of Synchrophasor

$$\text{Real part } = \text{ M} \bullet \text{ cos (angle)} \qquad \textbf{Equation J.5}$$

$$\text{Imaginary part } = \text{ M} \bullet \text{ sin (angle)} \qquad \textbf{Equation J.6}$$

Using the magnitude M from *Equation J.5*, the real part is given in *Equation J.7*.

$$\text{VAY\_REAL } = \text{ 134.140 kV} \bullet \text{ cos 104.400°}$$
$$= -33.359 \text{ kV} \qquad \textbf{Equation J.7}$$

Similarly, the imaginary part is calculated in *Equation J.8*.

$$\text{VAY\_IMG } = \text{ 134.140 kV} \bullet \text{ sin 104.400°}$$
$$= 129.926 \text{ kV} \qquad \textbf{Equation J.8}$$

Because the sampling reference is based on the GPS clock (IRIG-B signal) and not synchronized to the power system, an examination of successive synchrophasor data sets will almost always show some angular change between samples of the same signal. This is not a malfunction of the relay or the power system, but is merely a result of viewing data from one system with an instrument with an independent time base. In other words, a power system has a nominal frequency of either 50 or 60 Hz, but on closer examination, it is usually running a little faster or slower than nominal.

Settings for IEEE C37.118 Protocol Synchrophasors

The phasor measurement unit (PMU) settings are listed in *Table J.1*. The SEL-651R-2 uses C37.118 message format for PMU applications because of increased settings flexibility and the availability of software and hardware for synchrophasor concentration, processing, and control.

The Global enable setting EPMU must be set to Y before the remaining SEL-651R-2 synchrophasor settings are available. No synchrophasor data collection can take place when EPMU := N.

You must make the port settings in *Table J.4* or *Table J.5* to transmit data with synchrophasor protocol. It is possible to set EPMU := Y without using any ports for synchrophasor protocols. For example, the serial port **MET PM** ASCII command can still be used.

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Table J.1   PMU Settings in the SEL-651R-2 (Global Settings)

Global Settings	Description	Default
EPMU	Enable Synchronized Phasor Measurement (Y, N)	N[a]
MRATE	Messages per Second {1, 2, 5, 10, 25, or 50 when NFREQ := 50} {1, 2, 4, 5, 10, 12, 15, 20, 30, or 60 when NFREQ := 60}	2
PMAPP	PMU Application (F = Fast Response, N = Narrow Bandwidth)	N
PHCOMP	Frequency-Based Phasor Compensation (Y, N)	Y
PMSTN	Station Name (16 characters, mixed case)	STATION A
PMID	PMU Hardware ID (1–65534)	1
PHVOLT	Include Voltage Terminal (Y, Z, ALL)	Y
PHDATAV	Phasor Data Set, Voltages (V1, PH, ALL, NA)	V1
VYCOMP	Y Terminal Voltage Angle Compensation Factor (–179.99 to 180 degrees)	0.00
VZCOMP	Z Terminal Voltage Angle Compensation Factor (–179.99 to 180 degrees)	0.00
PHDATAI	Phasor Data Set, Currents (I1, PH, ALL, NA)	NA
IPCOMP	Phase Current Angle Compensation Factor (–179.99 to 180 degrees)	0.00
INCOMP	Neutral Current Angle Compensation Factor (–179.99 to 180 degrees)	0.00
PHNR[b]	Phasor Numeric Representation (I = Integer, F = Floating point)	I
PHFMT[b]	Phasor Format (R = Rectangular coordinates, P = Polar coordinates)	R
FNR	Frequency Numeric Representation (I = Integer, F = Float)	I
NUMDSW	Number of 16-bit Digital Status Words (0, 1, 2, 3, 4)	1

[a] Set EPMU := Y to access the remaining settings.
[b] Setting hidden when PHDATAV := NA and PHDATAI := NA.

Table J.2   PMU Settings in the SEL-651R-2 (Logic Settings)

Logic Settings	Description	Default
PMTRIG	Trigger (SELOGIC Equation)	0
TREA1	Trigger Reason Bit 1 (SELOGIC Equation)	0
TREA2	Trigger Reason Bit 2 (SELOGIC Equation)	0
TREA3	Trigger Reason Bit 3 (SELOGIC Equation)	0
TREA4	Trigger Reason Bit 4 (SELOGIC Equation)	0

Descriptions of Synchrophasor Settings

Definitions for the settings in *Table J.1* are as follows:

MRATE

Selects the message rate in messages per second for synchrophasor data streaming on serial ports.

Choose the MRATE setting that suits the needs of your PMU application. This setting is one of seven settings that determine the minimum port SPEED necessary to support the synchrophasor data packet rate and size. See *Communications Bandwidth for C37.118 Protocol on page J.14* for detailed information.

J.6 | Synchrophasors
Settings for IEEE C37.118 Protocol Synchrophasors

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PMAPP

Selects the type of digital filters used in the synchrophasor algorithm:

➤ The Narrow Bandwidth setting (N) represents filters with a cutoff frequency approximately ¼ of MRATE. The response in the frequency domain is narrower, and response in the time domain is slower. This method results in synchrophasor data that are free of aliasing signals and well suited for post-disturbance analysis.

➤ The Fast Response setting (F) represents filters with a higher cutoff frequency. The response in frequency domain is wider and the response in the time domain is faster. This method results in synchrophasor data that can be used in synchrophasor applications requiring more speed in tracking system parameters.

PHCOMP

Enables or disables frequency-based compensation for synchrophasors.

For most applications, set PHCOMP := Y to activate the algorithm that compensates for the magnitude and angle errors of synchrophasors for frequencies that are off nominal. Use PHCOMP := N if you are concentrating the SEL-651R-2 synchrophasor data with other PMU data that do not employ frequency compensation.

PMSTN and PMID

NOTE: The PMSTN setting is not the same as the SEL-651R-2 Group setting TID (Terminal Identifier), even though they share the same factory-default value.

Defines the name and number of the PMU.

The PMSTN setting is an ASCII string with as many as 16 characters. The PMID setting is a numeric value. Use your utility or synchrophasor data concentrator naming convention to determine these settings.

PHVOLT, PHDATAV, VYCOMP, and VZCOMP

PHVOLT selects which voltage terminal(s) data the Phasor Data Set setting (PHDATAV) applies to and can be set to Y, Z, or ALL. PHDATAV selects which voltage synchrophasors to include in the data packet. Consider the burden on your synchrophasor processor and offline storage requirements when deciding how much data to transmit. PHVOLT and PHDATAV are two of seven settings that determine the minimum port SPEED necessary to support the synchrophasor data packet rate and size. See *Communications Bandwidth for C37.118 Protocol on page J.14* for detailed information. The following examples are for PHVOLT set to ALL. If PHVOLT were set to Y or Z, only the VY or VZ terminal voltages would be included in the data packet.

NOTE: Global setting EPHANT has no effect on synchrophasors.

NOTE: For SEL-651R-2 models with LEA inputs, the VnYPAC and VnZPAC settings (where n = 1, 2, or 3) are used to compensate for phase angle shifts in the measurement path (see Voltage Phase Angle Correction Settings for VY- and VZ-Terminal Voltage Inputs (Global Settings) on page 9.36). In this case, the VYCOMP and VZCOMP settings do not need to be used to compensate for such phase angle shifts.

➤ PHDATAV := V1 will transmit only positive-sequence voltages, V1Y and V1Z.

➤ PHDATAV := PH will transmit VAY, VBY, VCY, VAZ, VBZ, and VCZ.

➤ PHDATAV := ALL will transmit V1Y, V1Z, VAY, VBY, VCY, VAZ, VBZ, and VCZ.

➤ PHDATAV := NA will not transmit any voltages.

Table J.3 describes the order of synchrophasors inside the data packet.

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The VYCOMP and VZCOMP settings allow correction for any steady-state voltage phase errors (from the potential transformers or wiring characteristics). VYCOMP corrects the Y terminal voltages for phase angle error. VZCOMP corrects the Z terminal voltages for phase angle error. See *Synchrophasor Measurement on page J.2* for details on this setting.

PHDATAI, IPCOMP, and INCOMP

PHDATAI selects which current synchrophasors to include in the data packet. Consider the burden on your synchrophasor processor and offline storage requirements when deciding how much data to transmit. This setting is one of seven settings that determine the minimum port SPEED necessary to support the synchrophasor data packet rate and size. See *Communications Bandwidth for C37.118 Protocol on page J.14* for detailed information.

➤ PHDATAI := I1 will transmit only positive-sequence current, I1

➤ PHDATAI := PH will transmit IA, IB, and IC

➤ PHDATAI := ALL will transmit I1, IA, IB, IC, and IN

➤ PHDATAI := NA will not transmit any currents

The IPCOMP and INCOMP settings allow correction for any steady-state phase errors (from the current transformers or wiring characteristics). See *Synchrophasor Measurement on page J.2* for details on these settings.

Table J.3 describes the order of synchrophasors inside the data packet. Synchrophasors are transmitted in the order indicated from the top to the bottom of the table. When PHFMT := R, real values are transmitted first and imaginary values are transmitted second. When PHFMT := P, magnitude values are transmitted first and angle values are transmitted second. Synchrophasors are only transmitted if specified to be included by the PHVOLT, PHDATAV, and PHDATAI settings. For example, if PHVOLT := Y, PHDATAV := ALL, and PHDATAI := I1, Y-terminal phase voltages will be transmitted first, followed by positive-sequence current and Y-terminal positive-sequence voltage.

Table J.3   Synchrophasor Order in Data Stream (Voltages and Currents)

Synchrophasors[a]	Scaling[b]	When Enabled[c]
Phase A Current	CTR	PHDATAI := PH or ALL
Phase B Current	CTR	PHDATAI := PH or ALL
Phase C Current	CTR	PHDATAI := PH or ALL
Neutral Current	CTRN	PHDATAI := ALL
Phase A Voltage Y Terminal	PTRY	PHVOLT has Y and PHDATAV := PH or ALL
Phase B Voltage Y Terminal	PTRY	PHVOLT has Y and PHDATAV := PH or ALL
Phase C Voltage Y Terminal	PTRY	PHVOLT has Y and PHDATAV := PH or ALL
Phase A Voltage Z Terminal	PTRZ	PHVOLT has Z and PHDATAV := PH or ALL
Phase B Voltage Z Terminal	PTRZ	PHVOLT has Z and PHDATAV := PH or ALL
Phase C Voltage Z Terminal	PTRZ	PHVOLT has Z and PHDATAV := PH or ALL
Positive-Sequence Current	CTR	PHDATAI := I1 or ALL
Positive-Sequence Voltage Y Terminal	PTRY	PHVOLT has Y and PHDATAV := V1 or ALL
Positive-Sequence Voltage Z Terminal	PTRZ	PHVOLT has Z and PHDATAV := V1 or ALL

[a] Synchrophasors are included in the order shown (for example phase currents, if selected, will always precede phase voltage).

[b] Synchrophasors are transmitted as primary values. Relay settings CTR, CTRN, PTRY, PTRZ are used to scale the values as shown.

J.8 | Synchrophasors
Settings for IEEE C37.118 Protocol Synchrophasors

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c Settings conditions that enable the synchrophasor data.

PHNR

Selects the numeric representation of voltage and current phasor data in the synchrophasor data stream.

This setting is one of seven settings that determine the minimum port SPEED necessary to support the synchrophasor data packet rate and size. See *Communications Bandwidth for C37.118 Protocol on page J.14* for detailed information.

The choices for this setting depend on synchrophasor processor requirements.

Setting PHNR := I sends each voltage and/or current synchrophasor as 2 two-byte integer values.

Setting PHNR := F sends each voltage and/or current synchrophasor as 2 four-byte floating-point values.

PHFMT

Selects the phasor representation of voltage and current phasor data in the synchrophasor data stream.

The choices for this setting depend on synchrophasor processor requirements.

Setting PHFMT := R (rectangular) sends each voltage or current synchrophasor as a pair of signed real and imaginary values.

Setting PHFMT := P (polar) sends each voltage or current synchrophasor as a magnitude and angle pair. The angle is in radians when PHNR := F, and in radians • 10^4 when PHNR := I. The range is as follows:

$$-\pi < \text{angle} \leq \pi.$$

In both the rectangular and polar representations, the values are scaled in rms (root-mean-square) units. For example, a synchrophasor with a magnitude of 1.0 at an angle of –30 degrees will have a real component of 0.866 and an imaginary component of –0.500. See *Synchrophasor Measurement on page J.2* for an example of conversion between polar and rectangular coordinates.

FNR

Selects the numeric representation of the two frequency values in the synchrophasor data stream.

This setting is one of seven settings that determine the minimum port SPEED necessary to support the synchrophasor data packet rate and size. See *Communications Bandwidth for C37.118 Protocol on page J.14* for detailed information.

The choices for this setting depend on synchrophasor processor requirements.

Setting FNR := I sends the frequency data as a difference from nominal frequency, NFREQ, with the following formula:

$$(\text{FREQ}_{\text{measured}} - \text{NFREQ}) \cdot 1000,$$

represented as a signed, two-byte value.

Setting FNR := I also sends the rate-of-change-of-frequency data with scaling.

$$DFDT_{measured} \cdot 100,$$

represented as a signed, two-byte value.

Setting FNR := F sends the measured frequency data and rate-of-change of frequency as two four-byte, floating-point values.

NUMDSW

Selects the number of user-definable digital status words to be included in the synchrophasor data stream.

This setting is one of seven settings that determine the minimum port SPEED necessary to support the synchrophasor data packet rate and size. See *Communications Bandwidth for C37.118 Protocol on page J.14* for detailed information.

The choices for this setting depend on the synchrophasor system design. The inclusion of digital data can help indicate breaker status or other operational data to the synchrophasor processor. For example, because VZ terminal Phase A synchrophasors are IEEE C37.118 Level 1 compliant only when the frequency is the same as the VY terminal Phase A voltage, it may be desirable to monitor breaker position to indicate when there might be a frequency difference. See *IEEE C37.118 PMU Setting Example on page J.18* for a suggested use of the digital status word fields.

Setting NUMDSW := 0 sends no user-definable digital status words.

Setting NUMDSW := 1 sends the user-definable digital status words containing Relay Word bits SV49–SV64.

Setting NUMDSW := 2 sends the user-definable digital status words containing Relay Word bits SV33–SV64.

Setting NUMDSW := 3 sends the user-definable digital status words containing Relay Word bits SV17–SV64.

Setting NUMDSW := 4 sends the user-definable digital status words containing Relay Word bits SV1–SV64.

The digital status words are sent last in the synchrophasor data packet starting with SV49–SV64.

TREA1, TREA2, TREA3, TREA4, and PMTRIG

NOTE: The PM Trigger function is not associated with the SEL-651R-2 Event Report Trigger ER, a SELOGIC control equation in Report settings.

Defines the programmable trigger bits as allowed by IEEE C37.118.

Each of the four Trigger Reason settings, TREA1–TREA4, and the PMU Trigger setting, PMTRIG, are SELOGIC control equations in Logic settings. The SEL-651R-2 evaluates these equations and places the results in Relay Word bits with the same names: TREA1–TREA4 and PMTRIG.

The trigger reason equations represent the Trigger Reason bits in the STAT field of the data packet. After the trigger reason bits are set to convey a message, the PMTRIG Equation should be asserted for a reasonable amount of time, to allow the synchrophasor processor to read the TREA1–TREA4 fields.

The IEEE C37.118 standard defines the first eight of 16 binary combinations of these trigger reason bits (bits 0–3). The remaining eight binary combinations are available for user definition.

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J.10 | Synchrophasors
Serial Port Settings for IEEE C37.118 Synchrophasors

The SEL-651R-2 does not automatically set the TREA1–TREA4 or PMTRIG Relay Word bits—these bits must be programmed even for the eight combinations defined by IEEE C37.118.

These bits may be used to send various messages at a low bandwidth via the synchrophasor message stream. Digital Status Words may also be used to send binary information directly, without the need to manage the coding of the trigger reason messages in SELOGIC.

Use these Trigger Reason bits if your synchrophasor system design requires these bits. The SEL-651R-2 synchrophasor processing and protocol transmission are not affected by the status of these bits.

Serial Port Settings for IEEE C37.118 Synchrophasors

IEEE C37.118 compliant synchrophasors are available via serial or Ethernet port. The associated serial port settings are shown in *Table J.4*.

Table J.4   SEL-651R-2 Serial Port Settings for Synchrophasors

Setting	Description	Default
EPORT	Enable Port (Y, N)	Y[a]
PROTO	Protocol (SEL, DNP, MOD, MBA, MBB, MB8A, MB8B, PMU)[b]	SEL[c]
SPEED	Data Speed (300 to 57600)	9600
STOP	Stop Bits (1, 2)	1
RTSCTS[d]	Enable Hardware Handshaking (Y, N)	N
FASTOP	Fast Operate Enabled (Y, N)[e]	N

[a] Set EPORT := Y to access the remaining settings.
[b] Some of the other PROTO setting choices may not be available.
[c] Set PROTO := PMU to enable C37.118 synchrophasor protocol on this port.
[d] The RTSCTS setting is not available on Port 1.
[e] See Synchrophasor Protocols and SEL Fast Operate Commands on page J.25.

The serial port settings for PROTO := PMU, shown in *Table J.4*, do not include the settings BITS and PARITY; these two settings are internally fixed as BITS = 8, PARITY = N.

Serial port setting PROTO cannot be set to PMU (see *Table J.4*) when Global setting EPMU := N. Synchrophasors must be enabled (EPMU := Y) before PROTO can be set to PMU. If the PROTO setting for any serial port is PMU, EMPU cannot be set to N.

If you use a computer terminal session or ACSELERATOR QuickSet SEL-5030 Software connected to a serial port, and then set that same serial port PROTO setting to PMU, you will lose the ability to communicate with the relay through ASCII commands. If this happens, either connect via another serial port (that has PROTO := SEL) or use the front-panel HMI SET/SHOW screen to change the port PROTO setting back to SEL.

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Synchrophasors J.11
Ethernet Port Settings for IEEE C37.118 Synchrophasors
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Ethernet Port Settings for IEEE C37.118 Synchrophasors

IEEE C37.118 compliant synchrophasors are available via serial or Ethernet port. The associated Ethernet port settings are shown in *Table J.5*.

Two PMU Ethernet Output sessions are available, except when IEC 61850 is enabled. When Port 5 setting E61850 := Y, only one PMU Ethernet output can be used.

Table J.5   SEL-651R-2 Ethernet Port Settings for Synchrophasors

Setting	Description	Default
EPMIP[a]	Enable PMU Processing (Y,N)	N[b]
PMOTS1	PMU Output 1 Transport Scheme (OFF, TCP, UDP_S, UDP_T, UDP_U)	OFF
PMOIPA1	PMU Output 1 Client IP (Remote) Address (www.xxx.yyy.zzz)	192.168.1.3
PMOTCP1	PMU Output 1 TCP/IP (Local) Port Number (1–65534)	4712
PMOUDP1	PMU Output 1 UDP/IP Data (Remote) Port Number (1–65534)	4713
PMOTS2[c]	PMU Output 2 Transport Scheme (OFF, TCP, UDP_S, UDP_T, UDP_U)	OFF
PMOIPA2[c]	PMU Output 2 Client IP (Remote) Address (www.xxx.yyy.zzz)	192.168.1.4
PMOTCP2[c]	PMU Output 2 TCP/IP (Local) Port Number (1–65534)	4722
PMOUDP2[c]	PMU Output 2 UDP/IP Data (Remote) Port Number (1–65534)	4713

[a] Setting is hidden when EPMU := N.
[b] Set EPMIP := Y to access other settings and to enable IEEE C37.118 protocol synchrophasors on this port. Setting EPMIP is not available when Global setting EPMU is set to N. EPMU cannot be set to N if EPMIP := Y on any Ethernet port.
[c] PMU Output 2 settings are not available when IEC 61850 functions are enabled.

Descriptions for some of the settings in *Table J.5* are as follows.

EPMIP.   Setting this to Y enables synchrophasor data transmission over Ethernet port. Setting this to N disables the synchrophasor data transmission over Ethernet port.

Ethernet port setting EPMIP cannot be set to Y (see *Table J.5*) when Global setting EPMU := N. Synchrophasors must be enabled (EPMU := Y) before EPMIP can be set to Y. If EPMIP := Y for any Ethernet port, EPMU cannot be set to N.

PMOTS[1,2].   Selects the PMU Output transport scheme for Session 1 and 2, respectively.

> ➤ PMOTS[1,2] := TCP establishes a single, persistent TCP socket for transmitting and receiving synchrophasor messages (both commands and data), as illustrated in *Figure J.5*.

J.12 Synchrophasors
Ethernet Port Settings for IEEE C37.118 Synchrophasors

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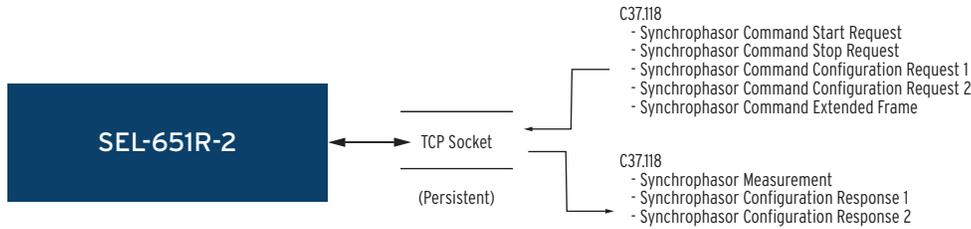
Figure J.5 TCP Connection

➤ PMOTS[1,2] := UDP_T establishes two socket connections. A nonpersistent TCP connection is used for receiving synchrophasor command messages as well as transmitting synchrophasor configuration and header response messages. A persistent UDP connection is used to transmit synchrophasor data messages. *Figure J.6* depicts the UDP_T connection.

➤ PMOTS[1,2] := UDP_U uses the same connection scheme as the UDP_T except the synchrophasor configuration and header response messages are sent over the UDP socket, as shown in *Figure J.6*.
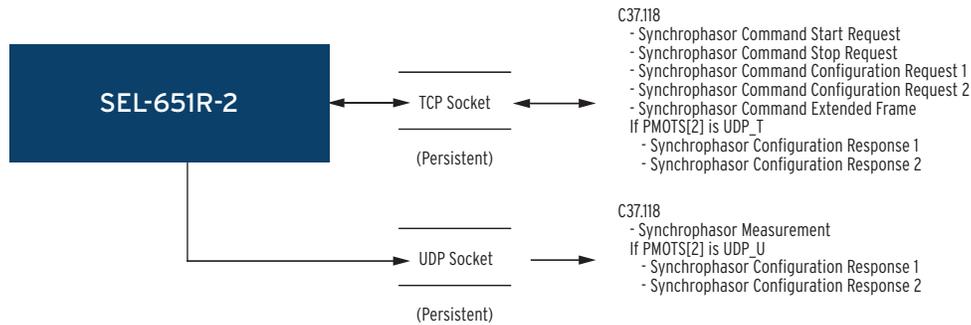
Figure J.6 UDP_T and UDP_U Connections

➤ PMOTS[1,2] := UDP_S establishes a single persistent UDP socket to transmit synchrophasor messages. Synchrophasor data are transmitted whenever new data are read. With this communications scheme, the relay sends a "Synchrophasor Configuration Response 2" once every minute, as shown in *Figure J.7*.
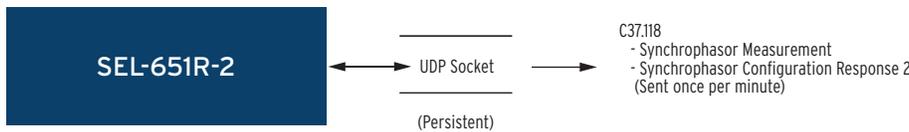
Figure J.7 UDP_S Connection

PMOIPA[1,2]. Defines the PMU Output Client IP address for Session 1 and Session 2, respectively.

PMOTCP[1,2]. Defines the TCP/IP (Local) port number for Session 1 and Session 2, respectively. These port numbers must all be unique.

PMOUDP[1,2]. Defines the UDP/IP (Remote) port number for Session 1 and Session 2, respectively. These port numbers must all be unique.

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Synchrophasors J.13
C37.118 Synchrophasor Protocol
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C37.118 Synchrophasor Protocol

The SEL-651R-2 complies with *IEEE C37.118, Standard for Synchrophasors for Power Systems*.

The protocol is available on serial ports 1, 2, 3, and F by setting the corresponding Port setting PROTO := PMU. The protocol is available on any Ethernet port when EPMIP := Y.

This subsection does not cover the details of the protocol, but highlights some of the important features and options that are available.

Settings Affect Message Contents

The SEL-651R-2 allows several options for transmitting synchrophasor data. These are controlled by Global settings described in *Settings for IEEE C37.118 Protocol Synchrophasors on page J.4*. You can select how often to transmit the synchrophasor messages (MRATE), which synchrophasors to transmit (PHVOLT, PHDATAV and PHDATAI), which numeric representation to use (PHNR), and which coordinate system to use (PHFMT).

The SEL-651R-2 automatically includes the frequency and rate-of-change of frequency in the synchrophasor messages. Global setting FNR selects the numeric format to use for these two quantities.

The relay can include as many as 64 digital status values, as controlled by Global setting NUMDSW.

The SEL-651R-2 always includes the results of four synchrophasor Trigger Reason SELOGIC control equations TREA1, TREA2, TREA3, and TREA4, and the trigger SELOGIC control equation result PMTRIG, in the synchrophasor message. *Table J.6* shows the contents of the SEL-651R-2 Data Frame.

Table J.6   C37.118 Data Frame (Sheet 1 of 2)

Field	Size (Bytes)	Description

SYNC	2	Bits 15 to 8—0xAA
		Bit 7—Reserved Always set to 0
		Bits 6 to 4—Frame identifier
		  000 for data frames
		  001 for header frames
		  010 for configuration 1 frames
		  011 for configuration 2 frames
		  100 for command frames
		Bits 3 to 0—Version of synchrophasor spec, set to 001

FRAMESIZE	2	Number of bytes in frame, 16 bit unsigned integer
IDCODE	2	PMID setting, 16 bit unsigned integer
SOC	4	Time stamp, 32 bit unsigned second of century from January 1, 1970
FRACSEC	4	Bit 31—Reserved. Always set to 0 Bit 30—Leap second direction, 0 for add, 1 for delete Bit 29—Leap second occurred. Set on the falling edge of leap second pending bit (LPSECP) if TIRIG = 1. Once set, Bit 29 remains set for 24 hours. Bit 28—Leap second pending. Follows LPSECP Bits 27 to 24—Time quality flags. TQUAL1 through TQUAL4 Bits 23 to 0—Fractions of a second 16777215*Message index for current second/MRATE

J.14 | Synchrophasors
C37.118 Synchrophasor Protocol

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Table J.6   C37.118 Data Frame (Sheet 2 of 2)

Field	Size (Bytes)	Description
STAT	2	Bit 15—Data Valid. Always set to 0 Bit 14—PMU error flag. Follows NOT(PMDOK) Bit 13—PMU Sync flag. Follows NOT(TSOK) Bit 12—Data sorting flag. Always set to 0. Bit 11—PMU trigger detected flag. Follows PMTRIG Bit 10—Configuration changed flag Bits 9 to 6—Reserved. Always set to 0 Bits 5 and 4—Time error 　00= best quality, synchronized. TSOK = 1 or TSOK = 0 for 10 seconds or less 　01= TSOK = 0 for 10 seconds to not more than 100 seconds 　10= TSOK = 0 for 100 seconds but less than 1000 seconds 　11= TSOK = 0 for 1000 seconds or longer Bits 3 to 0—Trigger reason 　Bit 3 follows TREA4 　Bit 2 follows TREA3 　Bit 1 follows TREA2 　Bit 0 follows TREA1
PHASORS	See *Table J.3* and *Table J.7*	Phasor data
FREQ	2 or 4	(Measured frequency-NFREQ)*100 if FNR=INT, Measured Frequency if FNR=FLOAT
DFREQ	2 or 4	Rate-of-change of frequency*100 if FNR=INT, Rate-of-change of frequency if FNR=FLOAT
ANALOG	0	No analog data are transmitted
DIGITAL	0 or 2	2 * NUMDSW
CHK	2	

Communications Bandwidth for C37.118 Protocol

A phasor measurement unit (PMU) that is configured to transmit a single synchrophasor (positive-sequence voltage, for example) at a message rate of once per second places little burden on the communications channel. As more synchrophasors or digital status words are added, or if the message rate is increased, some communications channel restrictions come into play.

If the SPEED setting on any serial port set with PROTO := PMU is insufficient for the PMU Global settings, the SEL-651R-2 or SEL-5030 software will display an error message and fail to save settings until the error is corrected.

The C37.118 synchrophasor message format always includes 18 bytes for the message header and terminal ID, time information, and status bits. The selection of synchrophasor data, numeric format, and programmable digital data will add to the byte requirements. *Table J.7* can be used to calculate the number of bytes in a synchrophasor message.

NOTE: There are no limitations placed on the number of bytes in the synchrophasor message and the message rate if only the Ethernet port is enabled for synchrophasors.

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Table J.7   Size of a C37.118 Synchrophasor Message

Item	Possible Number of Quantities	Bytes per Quantity	Minimum Number of Bytes	Maximum Number of Bytes
Fixed			18	18
Synchrophasors	0, 1, 2, 3, 4, 5, 6, 7, 8, 9, 11, 12, or 13	4 {PHNR := I} 8 {PHNR := F}	0	104
Frequency	2 (fixed)	2 {FNR := I} 4 {FNR := F}	4	8
Digital Status Words	0–4	2	0	8
Total (Minimum and Maximum)			22	138

Table J.8 lists the bps settings available on any SEL-651R-2 serial port (setting SPEED) and the maximum message size that can fit within the port bandwidth. Blank entries indicate bandwidths of less than 20 bytes.

Table J.8   Serial Port Bandwidth for Synchrophasors (in Bytes)

Global Setting MRATE	Port Setting SPEED							
	300	1200	2400	4800	9600	19200	38400	57600
1	25	103	207	414	829	1658	3316	4974
2		51	103	207	414	829	1658	2487
4 (60 Hz only)		25	51	103	207	414	829	1243
5		20	41	82	165	331	663	994
10			20	41	82	165	331	497
12 (60 Hz only)				34	69	138	276	414
15 (60 Hz only)				27	55	110	221	331
20 (60 Hz only)				20	41	82	165	248
25 (50 Hz only)					33	66	132	198
30 (60 Hz only)					27	55	110	165
50 (50 Hz only)						33	66	99
60 (60 Hz only)						27	55	82

Referring to *Table J.7* and *Table J.8*, it is clear that the lower SPEED settings are very restrictive.

The smallest practical synchrophasor message would be comprised of one synchrophasor and this message would consume between 26 and 34 bytes, depending on the numeric format settings. This type of message could be sent at any message rate (MRATE) when SPEED := 38400 or 57600, as high as MRATE := 50 or 30 when SPEED := 19200, and as high as MRATE := 25 or 20 when SPEED := 9600.

Another example application has messages comprised of 13 synchrophasors and four digital status words. This type of message would consume between 82 and 138 bytes, depending on the numeric format settings. The 82-byte version, using integer numeric representation, could be sent at as high as MRATE := 50 or 60 when SPEED := 57600. The 138-byte version, using floating-point numeric representation, could be sent at as high as MRATE := 25 or 30 when SPEED := 57600, as high as MRATE := 10 or 20 when SPEED := 38400, and as high as MRATE := 10 or 12 when SPEED := 19200.

J.16 | Synchrophasors
Synchrophasor Relay Word Bits

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Protocol Operation

The SEL-651R-2 will only transmit synchrophasor messages over serial ports that have setting PROTO := PMU. The connected device will typically be a synchrophasor processor, such as the SEL-3373. The synchrophasor processor controls the PMU functions of the SEL-651R-2 with IEEE C37.118 commands, including commands to start and stop synchrophasor data transmission, and commands to request a configuration block from the relay, so the synchrophasor processor can automatically build a database structure.

Transmit Mode Control

The SEL-651R-2 will not begin transmitting synchrophasors until an enable message is received from the synchrophasor processor. The relay will stop synchrophasor transmission when the appropriate command is received from the synchrophasor processor. The SEL-651R-2 can also indicate when a configuration change occurs, so the synchrophasor processor can request a new configuration block and keep its database up-to-date.

The SEL-651R-2 will only respond to configuration block request messages when it is in the nontransmitting mode.

Independent Ports

Each serial port with the PROTO := PMU setting is independently configured and enabled for synchrophasor commands. The ports are not required to have the same SPEED setting, although the slowest SPEED setting on a PROTO := PMU port will affect the maximum Global MRATE setting that can be used.

Synchrophasor Relay Word Bits

Table J.9 and *Table J.10* list the SEL-651R-2 Relay Word bits that are related to synchrophasor measurement.

The Synchrophasor Trigger Relay Word bits in *Table J.9* follow the state of the SELOGIC control equations of the same name, listed in *Table J.2*. These Relay Word bits are included in the IEEE C37.118 synchrophasor data frame STAT field. See *Table J.3* for standard definitions for these settings.

Table J.9   Synchrophasor Trigger Relay Word Bits

Name	Description
PMTRIG	Trigger (SELOGIC Equation)
TREA4	Trigger Reason Bit 4 (SELOGIC Equation)
TREA3	Trigger Reason Bit 3 (SELOGIC Equation)
TREA2	Trigger Reason Bit 2 (SELOGIC Equation)
TREA1	Trigger Reason Bit 1 (SELOGIC Equation)

The Time-Synchronization Relay Word bits in *Table J.10* indicate the present status of the high-accuracy timekeeping function of the SEL-651R-2 (see *Configuring High-Accuracy Timekeeping on page J.21*).

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Synchrophasors ➤ J.17
View Synchrophasors by Using the MET PM Command

Table J.10   Time-Synchronization Relay Word Bits

Name	Description
TIRIG	Asserts while relay time is based on IRIG-B time source.
TSOK	Time synchronization OK. Asserts while time is based on high-accuracy IRIG-B time source of sufficient accuracy for synchrophasor measurement.
IRIGOK	IRIG time source signal detected (= TIRIG OR TSOK).
PMDOK	Phasor measurement data OK. Asserts when the SEL-651R-2 is enabled, synchrophasors are enabled (Global setting EPMU := Y), the frequency calculated by the synchrophasor algorithm is within the frequency tracking range of the recloser control, and the positive-sequence voltage (for Y or Z Terminal, based on Global setting FSELECT) is greater than 10 V secondary. A few seconds may be required for PMDOK to assert when the relay is first powered, after any of the settings in *Table J.1* are changed, or when an IRIG-B time signal is first connected.

View Synchrophasors by Using the MET PM Command

The **MET PM** serial port ASCII command may be used to view the SEL-651R-2 synchrophasor measurements. See *MET Command (Metering Data) on page 10.57* for general information on the **MET** command.

There are multiple ways to use the **MET PM** command:

➤ As a test tool, to verify connections, phase rotation, and scaling.

➤ As an analytical tool, to capture synchrophasor data at an exact time to compare this information with similar data captured in other phasor measurement unit(s) at the same time.

➤ As a method of periodically gathering synchrophasor data through a communications processor.

The **MET PM** command displays the same set of analog synchrophasor information, regardless of the Global settings PHVOLT, PHDATAV and PHDATAI. The **MET PM** command can function even when no ports are sending synchrophasor data.

The **MET PM** command only displays data when the Relay Word bit TSOK = logical 1. *Figure J.8* shows a sample **MET PM** command response. The synchrophasor data are also available in the QuickSet HMI and have a similar format to *Figure J.8*.

The **MET PM** *time* command can be used to direct the SEL-651R-2 to display the synchrophasor for an exact specified time, in 24-hour format. For example, entering the command **MET PM 14:14:12** will result in a response similar to *Figure J.8* occurring just after 14:14:12, with the time stamp 14:14:12.000.

This method of data capture always reports from the exact second, even if the time parameter is entered with fractional seconds. For example, entering **MET PM 14:14:12.200** results in the same data capture as **MET PM 14:14:12**, because the relay ignored the fractional seconds.

J.18 | Synchrophasors
IEEE C37.118 PMU Setting Example

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See *MET PM (Synchrophasor Metering) on page 10.62* for complete command options and error messages.

MET PM HIS recalls the most recently triggered synchrophasor meter report. This is useful when synchrophasor data from multiple relays must be captured on a single PC. For example, connect to each relay and issue the **MET PM 14:14:00** command. At 14:14, each relay will issue a response similar to *Figure J.8*. After 14:14, connect to each relay, issue the **MET PM HIS** command, and capture the results. Because **MET PM HIS** recalls the last MET PM report, the data captured from every relay will be from the same time. Values displayed reflect present relay settings, not settings in effect at the time of the original **MET PM** command.

```
=>MET PM <Enter>

FEEDER 1                                    Date: 08/05/2011 Time: 14:38:27.000
STATION A                                   Time Source: external

                                                                  PMDOK = 1
Time Quality   Maximum time synchronization error:   0.000 (ms)  TSOK = 1

Synchrophasors
                 Y-Terminal Voltages        Pos.-Seq. Voltage
                VAY       VBY       VCY         V1Y
MAG (kV)      12.040    12.083    12.045      12.056
ANG (DEG)     48.925   -70.898   169.221      49.083


                 Z-Terminal Voltages        Pos.-Seq. Voltage
                VAZ       VBZ       VCZ         V1Z
MAG (kV)      12.033    12.060    12.024      12.039
ANG (DEG)     49.424   -70.429   169.750      49.581


                Phase Currents        Neutral Current   Pos.-Seq. Current
               IA        IB        IC          IN                I1
MAG (A)      987.906   989.363   988.834     0.868           988.689
ANG (DEG)     47.624   -72.086   168.303    46.693            47.947

FREQ (Hz) 60.004
Rate-of-change of FREQ (Hz/s)    0.00

Digitals

SV01   SV02   SV03   SV04   SV05   SV06   SV07   SV08
 0      0      0      0      0      0      0      0
SV09   SV10   SV11   SV12   SV13   SV14   SV15   SV16
 0      0      0      0      0      0      0      0
SV17   SV18   SV19   SV20   SV21   SV22   SV23   SV24
 0      0      0      0      0      0      0      0
SV25   SV26   SV27   SV28   SV29   SV30   SV31   SV32
 0      0      0      0      0      0      0      0
SV33   SV34   SV35   SV36   SV37   SV38   SV39   SV40
 0      0      0      0      0      0      0      0
SV41   SV42   SV43   SV44   SV45   SV46   SV47   SV48
 0      0      0      0      0      0      0      0
SV49   SV50   SV51   SV52   SV53   SV54   SV55   SV56
 0      0      0      0      0      0      0      0
SV57   SV58   SV59   SV60   SV61   SV62   SV63   SV64
 0      0      0      0      0      0      0      0

=>
```

Figure J.8   Sample MET PM Command Response

IEEE C37.118 PMU Setting Example

A utility is upgrading its distribution system to use reclosers with the SEL-651R-2 recloser control. The utility also wants to install phasor measurement units (PMUs) at each recloser to collect data to monitor voltages and currents throughout the system.

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The PMU data collection requirements call for the following data, collected at 10 messages per second:

➤ Frequency

➤ Positive-sequence voltage from the source side of the recloser

➤ Three-phase, positive-sequence, and neutral current

➤ Indication when the breaker is open

➤ Indication when the voltage or frequency information is unusable

The utility is able to meet the requirements with the SEL-651R-2 recloser controls, an SEL-2407 Satellite-Synchronized Clock, and an SEL-3373 Station Phasor Data Concentrator in each substation communicating to the recloser controls with SEL-3031 Serial Radio transceivers.

This example will cover the PMU settings in one of the SEL-651R-2 recloser controls.

Some system details:

➤ The nominal frequency is 60 Hz.

➤ The source PTs and wiring have a phase error of 1.20 degrees (lagging) at 60 Hz.

➤ The recloser CTs and wiring have a phase error of 1.50 degrees (lagging) at 60 Hz.

➤ The neutral CT of the recloser control is fed the summation of the phase CTs, so its phase error will be 1.50 degrees (lagging) at 60 Hz as well.

➤ The synchrophasor data will be using port 3, and the maximum bps allowed is 19200.

➤ The system designer specified floating-point numeric representation for the synchrophasor data, and rectangular coordinates.

➤ The system designer specified integer numeric representation for the frequency data.

➤ The system designer specified synchrophasor response, because the data are being used for system monitoring.

The protection settings will not be shown.

Determining Settings

The protection engineer performs a bandwidth check by using *Table J.7*, and determines the required message size. The system requirements, in order of appearance in *Table J.7*, are:

➤ 6 synchrophasors, in floating-point representation

➤ Integer representation for the frequency data

➤ 3 digital status bits, which require one status word

The message size is $18 + 6 \cdot 8 + 2 \cdot 2 + 1 \cdot 2 = 72$ bytes. Using *Table J.8*, the engineer verifies that the port bps of 19200 is adequate for the message, at 10 messages per second.

J.20 Synchrophasors
IEEE C37.118 PMU Setting Example

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The Protection SELOGIC Variables SV62, SV63, and SV64 will be used to transmit the breaker status, loss-of-potential alarm, and frequency measurement status, respectively.

Make the Global settings as shown in *Table J.11*.

Table J.11   Example Synchrophasor Global Settings

Setting	Description	Value
NFREQ	Nominal System Frequency (50, 60 Hz)	60
EPMU	Enable Synchronized Phasor Measurement (Y, N)	Y
MRATE	Messages per Second (1, 2, 4, 5, 10, 12, 15, 20, 30, 60)	10
PMAPP	PMU Application (F = Fast Response, N = Narrow Bandwidth)	F
PHCOMP	Frequency-Based Phasor Compensation (Y, N)	Y
PMSTN	Station Name (16 characters, mixed case)	SAMPLE1
PMID	PMU Hardware ID (1–65534)	14
PHVOLT	Include Voltage Terminal (Y, Z, ALL)	Y
PHDATAV	Phasor Data Set, Voltages (V1, PH, ALL, NA)	V1
VYCOMP	Y Terminal Voltage Angle Compensation Factor (–179.99 to 180 degrees)	1.20
PHDATAI	Phasor Data Set, Currents (I1, PH, ALL, NA)	ALL
IPCOMP	Phase Current Angle Compensation Factor (–179.99 to 180 degrees)	1.50
INCOMP	Neutral Current Angle Compensation Factor (–179.99 to 180 degrees)	1.50
PHNR	Phasor Numeric Representation (I = Integer, F = Floating point)	F
PHFMT	Phasor Format (R = Rectangular coordinates, P = Polar coordinates)	R
FNR	Frequency Numeric Representation (I = Integer, F = Float)	I
NUMDSW	Number of 16-bit Digital Status Words (0, 1, 2, 3, 4)	1

Table J.12   Example Synchrophasor Logic Settings

Logic Setting	Description	Value
PMTRIG	Trigger (SELOGIC Equation)	NA
TREA1	Trigger Reason Bit 1 (SELOGIC Equation)	NA
TREA2	Trigger Reason Bit 2 (SELOGIC Equation)	NA
TREA3	Trigger Reason Bit 3 (SELOGIC Equation)	NA
TREA4	Trigger Reason Bit 4 (SELOGIC Equation)	NA

The three Relay Word bits required in this example must be placed in certain SELOGIC variables. Make the settings in *Table J.13* in all eight settings groups.

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Table J.13   Example Synchrophasor SELOGIC Settings

Setting	Value
SV62	52A3P
SV63	LOP
SV64	FREQOK

Make the *Table J.14* settings for serial port 3 by using the **SET P 3** command.

Table J.14   Example Synchrophasor Port Settings

Setting	Description	Value
EPORT	Enable Port (Y, N)	Y
PROTO	Protocol (SEL, DNP, MBA, MBB, RTD, PMU)	PMU
SPEED	Data Speed (300 to 57600)	19200
STOP	Stop Bits (1, 2 bits)	1
RTSCTS	Enable Hardware Handshaking (Y, N)	N
FASTOP	Fast Operate Enabled (Y, N)	

Configuring High-Accuracy Timekeeping

The SEL-651R-2 features high-accuracy timekeeping when supplied with an IRIG-B signal. When the supplied clock signal is sufficiently accurate, the SEL-651R-2 can act as a phasor measurement unit (PMU) and transmit synchrophasor data representative of the power system at fixed time periods to an external data processor. The relay can also record event report data by using the high-accuracy time stamp (see *Synchrophasor-Level Accuracy in Event Reports on page 12.31*).

IRIG Standard 200-04 defines many different types of time code formats. IRIG-B002, or "standard IRIG-B" provides time data once per second. The time data are formatted as second of the minute, minute of the hour, hour of the day, and day of the year. IRIG-B000, or extended IRIG-B, adds control functions that are defined based on the application. In this manual, IRIG-B000 is used to identify a time signal containing the control functions defined by IEEE C37.118 Standard for Synchrophasors for Power Systems. These control functions include the year, leap second and daylight saving time information, UTC offset, time quality indicator codes, and a parity bit.

IRIG-B

The SEL-651R-2 has two input connectors that accept IRIG-B demodulated time-code format: the IRIG-B pins of Serial Port 2 and the IRIG-B BNC connector.

The IRIG-B connections can be used for high-accuracy timekeeping purposes, with as high as 1 μs accuracy with an appropriate time source. Either input can also be used for general-purpose timekeeping with as high as 5 ms accuracy. See *Table J.15* for SEL-651R-2 timekeeping mode details.

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Configuring High-Accuracy Timekeeping

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Table J.15   SEL-651R-2 Timekeeping Modes

Item	Internal Clock	Normal Accuracy IRIG	Holdover	High-Accuracy IRIG
Best accuracy (condition)	Depends on last method of setting, plus internal clock drift[a]	5 ms (when IRIG-B signal not meeting requirements for high-accuracy IRIG is connected)		1 μs (when time source jitter is less than 500 ns and time-error is less than 1 μs)[b]
IRIG-B Connection Required	None	BNC connector (preferred), or Serial Port 2		BNC connector (preferred) or Serial Port 2
Relay Word bits	TIRIG = logical 0 TSOK = logical 0 IRIGOK = logical 0	TIRIG = logical 1 TSOK = logical 0 IRIGOK = logical 1	TIRIG = logical 0 TSOK = logical 1 IRIGOK = logical 1	TIRIG = logical 1 TSOK = logical 1 IRIGOK = logical 1

[a] The SEL-651R-2 internal clock can be synchronized via SNTP, DNP3, SEL-2030 Communications Processor, SEL-3530 RTAC, or ASCII TIM command.

[b] The time-error check only applies when Global setting IRIGC := C37.118.

NOTE: If the time-code signal connected to the BNC connector degrades in quality, the SEL-651R-2 will not switch over to the IRIG-B pins of Serial Port 2. The SEL-651R-2 will only switch to Serial Port 2 if the signal on the BNC connector completely fails (e.g., the cable is un-plugged). Use the TIME Q command to determine which IRIG-B source is in use.

Only one IRIG-B time source can be used by the SEL-651R-2. The relay uses IRIG-B signals from the two sources with the following priority:

➤ BNC input

➤ Serial Port 2 IRIG-B pins

The SEL-651R-2 determines the suitability of the IRIG-B signal for Normal Accuracy IRIG by applying several tests:

➤ Seconds, minutes, and day field is in range

➤ Time from two consecutive messages differ by 1 second, except for leap second or daylight saving time transitions.

➤ When IRIGC=C37.118, the signal contains the correct parity bit.

The SEL-651R-2 determines the suitability of the IRIG-B signal for high-accuracy timekeeping by applying two additional tests:

➤ The jitter between positive transitions (rising edges) of the clock signal is less than 500 ns.

➤ The time-error information contained in the IRIG-B control field indicates time error is less than 10^{-6} seconds (1 μs).

NOTE: Set IRIGC = C37.118 only when an IRIG-B000 signal is connected to the relay. Set IRIGC = NONE when an IRIG-B002 (standard IRIG) signal is connected.

When IRIGC := C37.118, the SEL-651R-2 will assert Relay Word bit TSOK only when these two tests are met. When IRIGC := NONE, the relay will assert TSOK when only the first test is met.

The relay accepts C37.118 (IRIG-B000) signals with either odd or even parity. When an IRIG-B signal is connected, the relay detects whether the signal has odd or even parity and continues to check received IRIG-B messages for that parity. If a message is received with the opposite parity or no parity, the signal fails the parity test.

If your clock has programmable parity and the parity is changed, the relay disqualifies the IRIG-B signal for a few seconds until it detects that the parity change is not a result of corrupt messages.

If the relay is in high-accuracy mode and either of the two tests fails, the relay enters holdover mode. When in holdover, the relay asserts TSOK, deasserts TIRIG, and holds Relay Word bits TQUAL1, TQUAL2, TQUAL3, and TQUAL4 at their last state. The relay remains in holdover mode for as long as 15 seconds, and then reverts to high-accuracy IRIG, normal-accuracy IRIG, or internal clock, depending on conditions.

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If you connect two IRIG-B sources, they should be of the same format (IRIG-B000 with C37.118 control extensions or IRIG-B002) and match the IRIGC setting. SEL does not recommend connecting different types of signals to different inputs (for example, an IRIG-B000 signal to the BNC input and an IRIG-B002 signal to Port **1** or Port **2**) when IRIGC=C37.118. The IRIG-B002 signal provides neither the year nor the parity bit required for Normal Accuracy mode when IRIGC=C37.118. In this case, if the IRIG-B000 source fails, relay timekeeping reverts to the internal clock, but the relay year changes to 2000 and remain incorrect until the IRIG-B000 signal returns. The relay will update the time from the IRIG-B002 signal about once every 10 seconds, if the signal passes the remaining two tests for Normal Accuracy mode. Relay Word bit TIRIG asserts momentarily during the update.

Table J.16   Time and Date Management

Label	Prompt	Default Value
IRIGC[a]	IRIG-B Control Bits Definition (None, C37.118)	None

[a] When EPMU := Y, IRIGC is forced to C37.118.

A time quality value is determined based on the four-bit Time Quality indicator code defined in the IEEE C37.118 standard. When Global setting IRIGC := C37.118, the raw time quality information from the IRIG-B signal is placed into four Relay Word bits TQUAL1, TQUAL2, TQUAL3, and TQUAL4. For example, if TQAUL1 := 1, TQUAL2 := 0, TQUAL3 := 1, and TQUAL4 := 0, the binary time quality indicator code received from the clock via the IRIG signal is 0101, which corresponds to 10 microseconds time error. See *Table J.17* for time quality decoding. The time quality is shown in the MET PM report beside the label `Time Quality Maximum time synchronization error:` viewed with the **MET PM** command, and in the **TIM Q** command.

Table J.17   Time Quality Decoding

TQUAL	Time Quality	TQUAL	Time Quality
0000	Locked	1000	10 milliseconds
0001	1 nanosecond	1001	100 milliseconds
0010	10 nanoseconds	1010	1 second
0011	100 nanoseconds	1011	10 seconds
0100	1 microsecond	1100	100 seconds
0101	10 microseconds	1101	1000 seconds
0110	100 microseconds	1110	10,000 seconds
0111	1 millisecond	1111	Fault

When IRIGC := C37.118, the relay also decodes Leap Second Pending, Leap Second Direction, Daylight Savings Pending, and Daylight Saving control bits that are present in the IRIG-B signal. The status of these control bits is reflected in Relay Word bits LPSECP, LPSEC, DSTP, and DST, respectively.

When IRIGC := NONE, the TQUAL1, TQUAL2, TQUAL3, TQUAL4, LPSECP, LPSEC, DSTP, and DST Relay Word bits are not updated. When Global setting EPMU := Y, IRIGC is forced to C37.118.

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Connecting High-Accuracy Timekeeping

The procedure in the following steps assumes that you have a modern high-accuracy GPS receiver with a BNC connector output for an IRIG-B signal. Use a communications terminal to send commands and receive data from the relay.

This example assumes that you have successfully established communication with the relay. In addition, you must be familiar with relay access levels and passwords.

Step 1. Confirm that the relay is operating.

Step 2. Prepare to control the relay at Access Level 2.

a. Using a communications terminal, type **ACC <Enter>**.

b. Type the Access Level 1 password and press **<Enter>**.

You will see the Access Level 1 => prompt.

Step 3. Connect the cable.

Attach the IRIG-B signal with a BNC-to-BNC coaxial jumper cable from the GPS receiver IRIG-B output to the SEL-651R-2 **IRIG-B** BNC connector.

Step 4. Confirm/Enable automatic detection of high-accuracy timekeeping.

a. Wait at least 20 seconds for the SEL-651R-2 to acquire the clock signal, and then, at a communications terminal, type **TAR TIRIG <Enter>**

The relay will return one row from the Relay Word, as shown in *Figure J.9*. Only the states of the TIRIG and TSOK Relay Word bits are discussed in the troubleshooting steps below.

```
=>TAR TIRIG <Enter>

TSOK     TIRIG    PMDOK    PMTRIG   TREA4    TREA3    TREA2    TREA1
1        1        1        0        0        0        0        0
=>
```

Figure J.9   Confirming the High-Accuracy Timekeeping Relay Word Bits

b. The TIRIG and TSOK Relay Word bits should be asserted (logical 1), indicating that the relay is in the high-accuracy IRIG timekeeping mode.

If TSOK is not asserted, but TIRIG is asserted, the relay is in regular IRIG timekeeping mode. The **TIME Q** command shows which IRIG-B source is in use and the time quality. Here is a list of possible reasons for not entering high-accuracy mode:

➢ Global setting IRIGC := C37.118, but the IRIG-B clock does not use the IEEE C37.118 Control Bit assignments.

➢ The IRIG-B signal jitter is too high.

➢ The termination resistor, required by some IRIG clocks, is not installed.

➢ Global setting IRIGC := C37.118, but the time-source clock is reporting that its time error is greater than 1 μs.

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If neither TSOK nor TIRIG are asserted, the relay is not in an IRIG time-source mode. Here is a list of possible reasons for not entering IRIG mode:

➢ The IRIG-B clock signal is not of sufficient accuracy or is improperly configured.

➢ The termination resistor, required by some IRIG clocks, is not installed.

➢ The time source clock is not connected to an antenna.

Synchrophasor Protocols and SEL Fast Operate Commands

The SEL-651R-2 can be configured to process SEL Fast Operate commands received on serial ports that have Port setting PROTO := PMU, when the Port setting FASTOP := Y.

This functionality can allow a host device to initiate control actions in the PMU without the need for a separate communications interface.

If port setting FASTOP := Y on a serial port set to PROTO := PMU, the SEL-651R-2 will provide Fast Operate support. The host device can request a Fast Operate Configuration Block when the relay is in the nontransmitting mode, and the relay will respond with the message, which includes codes that define the circuit breaker and remote bit control points that are available via Fast Operate commands.

The SEL-651R-2 will process Fast Operate requests regardless of whether synchrophasors are being transmitted, as long as serial port setting FASTOP := Y. When FASTOP := N, the relay will ignore Fast Operate commands. Use the FASTOP := N option to lock out any control actions from that serial port if required by your company operating practices.

The SEL-651R-2 does not acknowledge received Fast Operate commands, but it is easy to program one or more Relay Word bits to observe the controlled function. For example, a Fast Operate Circuit Breaker close command could be confirmed by monitoring the breaker status bit 52A3P by assigning SELOGIC setting SV32 := 52A3P.

Note that only the Fast Operate function is available on ports set to PROTO := PMU. The protocols SEL Fast Meter and SEL Fast SER are unavailable on PROTO := PMU ports.

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Appendix K

Modbus RTU and TCP Communications

Overview

This appendix describes Modbus RTU and TCP communications features supported by the SEL-651R-2 Recloser Control. Complete specifications for the Modbus protocol are available from the Modbus user's group website at www.modbus.org.

The SEL-651R-2 allows as many as three simultaneous Modbus sessions. The number of Ethernet Modbus sessions is limited by the number of enabled Ethernet DNP sessions (see *Session Limits on page 10.14*).

The SEL-651R-2 Modbus communication allows a Modbus master device to do the following:

➤ Acquire metering, monitoring, and event data from the relay.

➤ Control SEL-651R-2 output contacts and remote bits.

➤ Read and switch the Active Settings Group.

➤ Read and set the time and date.

➤ Reset targets, demand and peak data, energy data, breaker monitor, min/max, and event history data.

Enable Modbus TCP protocol with the Ethernet port setting EMODBUS. The master IP address for each session is selected with the Ethernet port settings MODIP1, MODIP2, and MODIP3. The Master IP address 0.0.0.0 is a valid entry and is used to accept a connection from any master. Use caution when using this address as any Modbus master may connect to the Ethernet port through this connection. When a Modbus TCP master attempts to connect, the relay will first search the valid master IP addresses. If no matching Modbus master IP address is found and one of the MODIP*x* addresses is 0.0.0.0, the master will be allowed to connect through that connection. The TCP port number is the Modbus TCP registered port 502. Modbus TCP uses the device IP address as the Modbus identifier and accesses the data in the relay through use of the same function codes and data maps as Modbus RTU.

Modbus RTU is a binary protocol that permits communication among a single master device and multiple slave devices. The communication is half duplex—only one device transmits at a time. The master transmits a binary command that includes the address of the desired slave device. All of the slave devices receive the message, but only the slave device with the matching address responds. Enable Modbus RTU protocol with the serial port PROTO = MOD setting.

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K.2 | Modbus RTU and TCP Communications
Communications Protocol

Communications Protocol

Modbus RTU Queries

Modbus master devices initiate all exchanges by sending a query. The query format for Modbus RTU consists of the fields shown in *Table K.1*.

Table K.1 Modbus Query Fields

Field	Number of Bytes
Slave Device Address	1 byte
Function Code	1 byte
Data Region	0–251 bytes
Cyclic Redundancy Check (CRC)	2 bytes

The SEL-651R-2 serial port SLAVEID setting defines the device address. Set this value to a unique number for each device on the Modbus network. For Modbus RTU communication to operate properly, no two slave devices may have the same address.

The cyclic redundancy check detects errors in the received data. If an error is detected, the relay discards the packet.

Modbus TCP Queries

The Modbus request or response is encapsulated when carried on a Modbus TCP/IP network. A dedicated header used on TCP/IP identifies the Modbus Application Data Unit (ADU). The header, called the Modbus Application Protocol header (MBAP), contains the following fields:

Field	Number of Bytes
Transaction Identifier	2 Bytes
Protocol Identifier	2 Bytes (0 = MODBUS protocol)
Length	2 Bytes
Unit Identifier	1 Byte

The Modbus TCP Message consists of the MBAP Header, followed by the Modbus function code and the data supporting the function code. The Modbus TCP message does not contain the 2-byte CRC that is included in the RTU message, as the error checking is accomplished through TCP. Otherwise, the data following the MBAP header are identical to the Modbus RTU message.

The remainder of this section will cover the Modbus Function codes in terms of the Modbus RTU protocol.

Modbus Responses

The slave device sends a response message after it performs the action the query specifies. If the slave cannot execute the query command for any reason, it sends an error response. Otherwise, the slave device response is formatted similarly to the query and includes the slave address, function code, data (if applicable), and a cyclic redundancy check value.

Supported Modbus Function Codes

The SEL-651R-2 supports the Modbus function codes shown in *Table K.2*.

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Communications Protocol

Table K.2   SEL-651R-2 Modbus Function Codes

Codes	Description
01h	Read Discrete Output Coil Status
02h	Read Discrete Input Status
03h	Read Holding Registers
04h	Read Input Registers
05h	Force Single Coil
06h	Preset Single Register
08h	Diagnostic Command
10h	Preset Multiple Registers

Modbus Exception Responses

The SEL-651R-2 sends an exception code under the conditions described in *Table K.3*.

Table K.3   SEL-651R-2 Modbus Exception Codes

Exception Code	Error Type	Description
1	Illegal Function Code	The received function code is either undefined or unsupported.
2	Illegal Data Address	The received command contains an unsupported address in the data field.
3	Illegal Data Value	The received command contains a value that is out of range.
4	Device Error	The SEL-651R-2 is in the wrong state for the function a query specifies.
		The relay is unable to perform the action specified by a query (i.e., cannot write to a read-only register, device is disabled, etc.).
6	Busy	The device is unable to process the command at this time because of a busy resource.

In the event that any of the errors listed in *Table K.3* occur, the relay assembles a response message that includes the exception code in the data field. The relay sets the most significant bit in the function code field to indicate to the master that the data field contains an error code, instead of the required data.

Cyclic Redundancy Check

The SEL-651R-2 calculates a 2-byte CRC value by using the device address, function code, and data region (see *Table K.1*). It appends this value to the end of every Modbus RTU response. When the master device receives the response, it recalculates the CRC. If the calculated CRC matches the CRC sent by the SEL-651R-2, the master device uses the data received. If there is no match, the check fails and the message is ignored. The devices use a similar process when the master sends queries.

01h Read Discrete Output Coil Status Command

Use function code 01h to read the On/Off status of the selected bits (coils) (see the Output Coils table shown in *Table K.14*). The SEL-651R-2 coil addresses start at 0. The coil status is packed one coil per bit of the data field. The least significant bit (LSB) of the first data byte contains the starting coil address in the query. The other coils follow towards the high order end of this byte and from low order to high order in subsequent bytes.

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Table K.4   01h Read Discrete Output Coil Status Command

Bytes	Field
Requests from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (01h)
2 bytes	Address of the first bit
2 bytes	Number of bits to read
2 bytes	CRC-16
A successful response from the slave will have the following format:	
1 byte	Slave Address
1 byte	Function Code (01h)
1 byte	Bytes of data (*n*)
n bytes	Data
2 bytes	CRC-16

To build the response, the SEL-651R-2 calculates the number of bytes required to contain the number of bits requested. If the number of bits requested is not evenly divisible by eight, the device adds one more byte to maintain the balance of bits, padded by zeros to make an even byte. *Table K.14* includes the coil number and lists all possible coils (identified as Outputs and Remote bits) available in the device.

The relay responses to errors in the query are shown in *Table K.5*.

Table K.5   Responses to 01h Read Discrete Output Coil Query Errors

Error	Error Code Returned	Communication Counter Increments
Invalid bit to read	Illegal Data Address (02h)	Invalid Address
Invalid number of bits to read	Illegal Data Value (03h)	Illegal Register
Format error	Illegal Data Value (03h)	Bad Packet Format

02h Read Input Status Command

Use function code 02h to read the On/Off status of the selected bits (inputs), as shown in *Table K.7*. Input addresses start at 0. The input status is packed one input per bit of the data field. The LSB of the first data byte contains the starting input address in the query. The other inputs follow towards the high order end of this byte, and from low order to high order in subsequent bytes.

Table K.6   02h Read Input Status Command (Sheet 1 of 2)

Bytes	Field
Requests from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (02h)
2 bytes	Address of the first bit
2 bytes	Number of bits to read
2 bytes	CRC-16

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Table K.6 02h Read Input Status Command (Sheet 2 of 2)

Bytes	Field
A successful response from the slave will have the following format:	
1 byte	Slave Address
1 byte	Function Code (02h)
1 byte	Bytes of data (*n*)
n bytes	Data
2 bytes	CRC-16

To build the response, the device calculates the number of bytes required to contain the number of bits requested. If the number of bits requested is not evenly divisible by eight, the device adds one more byte to maintain the balance of bits, padded by zeros to make an even byte.

In each row, the input numbers are assigned from the right-most input to the left-most input (i.e., input address 0 is TLED18 and input address 7 is TLED11). Input addresses start at 0000. *Table K.7* includes the input address in decimal and hexadecimal and lists all possible inputs (Relay Word bits) available in the device.

Table K.7 02h SEL-651R-2 Inputs[a] (Sheet 1 of 5)

Discrete Input Address in Decimal	Discrete Input Address in Hex	Function Code Supported	Discrete Address Description	Notes
0–7	0–7	2	Relay Element Status Row 0	The Address numbers are assigned from the right-most Address to the left-most Address in the Relay Word row as shown in the SEL-651R-2 example below. Address 7 = EN Address 6 = TRIPLED Address 5 = * Address 4 = * Address 3 = * Address 2 = * Address 1 = * Address 0 = *
8–15	8–F	2	Relay Element Status Row 1	Address 15 = TLED_08 Address 14 = TLED_07 Address 13 = TLED_06 Address 12 = TLED_05 Address 11 = TLED_04 Address 10 = TLED_03 Address 9 = TLED_02 Address 8 = TLED_01
16–23	10–17	2	Relay Element Status Row 2	
24–31	18–1F	2	Relay Element Status Row 3	
32–39	20–27	2	Relay Element Status Row 4	
40–47	28–2F	2	Relay Element Status Row 5	
48–55	30–37	2	Relay Element Status Row 6	
56–63	38–3F	2	Relay Element Status Row 7	
64–71	40–47	2	Relay Element Status Row 8	
72–79	48–4F	2	Relay Element Status Row 9	
80–87	50–57	2	Relay Element Status Row 10	

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Table K.7   02h SEL-651R-2 Inputs[a] (Sheet 2 of 5)

Discrete Input Address in Decimal	Discrete Input Address in Hex	Function Code Supported	Discrete Address Description	Notes
88–95	58–5F	2	Relay Element Status Row 11	
96–103	60–67	2	Relay Element Status Row 12	
104–111	68–6F	2	Relay Element Status Row 13	
112–119	70–77	2	Relay Element Status Row 14	
120–127	78–7F	2	Relay Element Status Row 15	
128–135	80–87	2	Relay Element Status Row 16	
136–143	88–8F	2	Relay Element Status Row 17	
144–151	90–97	2	Relay Element Status Row 18	
152–159	98–9F	2	Relay Element Status Row 19	
160–167	A0–A7	2	Relay Element Status Row 20	
168–175	A8–AF	2	Relay Element Status Row 21	
176–183	B0–B7	2	Relay Element Status Row 22	
184–191	B8–BF	2	Relay Element Status Row 23	
192–199	C0–C7	2	Relay Element Status Row 24	
200–207	C8–CF	2	Relay Element Status Row 25	
208–215	D0–D7	2	Relay Element Status Row 26	
216–223	D8–DF	2	Relay Element Status Row 27	
224–231	E0–E7	2	Relay Element Status Row 28	
232–239	E8–EF	2	Relay Element Status Row 29	
240–247	F0–F7	2	Relay Element Status Row 30	
248–255	F8–FF	2	Relay Element Status Row 31	
256–263	100–107	2	Relay Element Status Row 32	
264–271	108–10F	2	Relay Element Status Row 33	
272–279	110–117	2	Relay Element Status Row 34	
280–287	118–11F	2	Relay Element Status Row 35	
288–295	120–127	2	Relay Element Status Row 36	
296–303	128–12F	2	Relay Element Status Row 37	
304–311	130–137	2	Relay Element Status Row 38	
312–319	138–13F	2	Relay Element Status Row 39	
320–327	140–147	2	Relay Element Status Row 40	
328–335	148–14F	2	Relay Element Status Row 41	
336–343	150–157	2	Relay Element Status Row 42	
344–351	158–15F	2	Relay Element Status Row 43	
352–359	160–167	2	Relay Element Status Row 44	
360–367	168–16F	2	Relay Element Status Row 45	
368–375	170–177	2	Relay Element Status Row 46	
376–383	178–17F	2	Relay Element Status Row 47	
384–391	180–187	2	Relay Element Status Row 48	
392–399	188–18F	2	Relay Element Status Row 49	
400–407	190–197	2	Relay Element Status Row 50	

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Table K.7   02h SEL-651R-2 Inputs[a] **(Sheet 3 of 5)**

Discrete Input Address in Decimal	Discrete Input Address in Hex	Function Code Supported	Discrete Address Description	Notes
408–415	198–19F	2	Relay Element Status Row 51	
416–423	1A0–1A7	2	Relay Element Status Row 52	
424–431	1A8–1AF	2	Relay Element Status Row 53	
432–439	1B0–1B7	2	Relay Element Status Row 54	
440–447	1B8–1BF	2	Relay Element Status Row 55	
448–455	1C0–1C7	2	Relay Element Status Row 56	
456–463	1C8–1CF	2	Relay Element Status Row 57	
464–471	1D0–1D7	2	Relay Element Status Row 58	
472–479	1D8–1DF	2	Relay Element Status Row 59	
480–487	1E0–1E7	2	Relay Element Status Row 60	
488–495	1E8–1EF	2	Relay Element Status Row 61	
496–503	1F0–1F7	2	Relay Element Status Row 62	
504–511	1F8–1FF	2	Relay Element Status Row 63	
512–519	200–207	2	Relay Element Status Row 64	
520–527	208–20F	2	Relay Element Status Row 65	
528–535	210–217	2	Relay Element Status Row 66	
536–543	218–21F	2	Relay Element Status Row 67	
544–551	220–227	2	Relay Element Status Row 68	
552–559	228–22F	2	Relay Element Status Row 69	
560–567	230–237	2	Relay Element Status Row 70	
568–575	238–23F	2	Relay Element Status Row 71	
576–583	240–247	2	Relay Element Status Row 72	
584–591	248–24F	2	Relay Element Status Row 73	
592–599	250–257	2	Relay Element Status Row 74	
600–607	258–25F	2	Relay Element Status Row 75	
608–615	260–267	2	Relay Element Status Row 76	
616–623	268–26F	2	Relay Element Status Row 77	
624–631	270–277	2	Relay Element Status Row 78	
632–639	278–27F	2	Relay Element Status Row 79	
640–647	280–287	2	Relay Element Status Row 80	
648–655	288–28F	2	Relay Element Status Row 81	
656–663	290–297	2	Relay Element Status Row 82	
664–671	298–29F	2	Relay Element Status Row 83	
672–679	2A0–2A7	2	Relay Element Status Row 84	
680–687	2A8–2AF	2	Relay Element Status Row 85	
688–695	2B0–2B7	2	Relay Element Status Row 86	
696–703	2B8–2BF	2	Relay Element Status Row 87	
704–711	2C0–2C7	2	Relay Element Status Row 88	
712–719	2C8–2CF	2	Relay Element Status Row 89	
720–727	2D0–2D7	2	Relay Element Status Row 90	

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Table K.7 O2h SEL-651R-2 Inputs[a] (Sheet 4 of 5)

Discrete Input Address in Decimal	Discrete Input Address in Hex	Function Code Supported	Discrete Address Description	Notes
728–735	2D8–2DF	2	Relay Element Status Row 91	
736–743	2E0–2E7	2	Relay Element Status Row 92	
744–751	2E8–2EF	2	Relay Element Status Row 93	
752–759	2F0–2F7	2	Relay Element Status Row 94	
760–767	2F8–2FF	2	Relay Element Status Row 95	
768–775	300–307	2	Relay Element Status Row 96	
776–783	308–30F	2	Relay Element Status Row 97	
784–791	310–317	2	Relay Element Status Row 98	
792–799	318–31F	2	Relay Element Status Row 99	
800–807	320–327	2	Relay Element Status Row 100	
808–815	328–32F	2	Relay Element Status Row 101	
816–823	330–337	2	Relay Element Status Row 102	
824–831	338–33F	2	Relay Element Status Row 103	
832–839	340–347	2	Relay Element Status Row 104	
840–847	348–34F	2	Relay Element Status Row 105	
848–855	350–357	2	Relay Element Status Row 106	
856–863	358–35F	2	Relay Element Status Row 107	
864–871	360–367	2	Relay Element Status Row 108	
872–879	368–36F	2	Relay Element Status Row 109	
880–887	370–377	2	Relay Element Status Row 110	
888–895	378–37F	2	Relay Element Status Row 111	
896–903	380–387	2	Relay Element Status Row 112	
904–911	388–38F	2	Relay Element Status Row 113	
912–919	390–397	2	Relay Element Status Row 114	
920–927	398–39F	2	Relay Element Status Row 115	
928–935	3A0–3A7	2	Relay Element Status Row 116	
936–943	3A8–3AF	2	Relay Element Status Row 117	
944–951	3B0–3B7	2	Relay Element Status Row 118	
952–959	3B8–3BF	2	Relay Element Status Row 119	
960–967	3C0–3C7	2	Relay Element Status Row 120	
968–975	3C8–3CF	2	Relay Element Status Row 121	
976–983	3D0–3D7	2	Relay Element Status Row 122	
984–991	3D8–3DF	2	Relay Element Status Row 123	
992–999	3E0–3E7	2	Relay Element Status Row 124	

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Table K.7   02h SEL-651R-2 Inputs[a] **(Sheet 5 of 5)**

Discrete Input Address in Decimal	Discrete Input Address in Hex	Function Code Supported	Discrete Address Description	Notes
1000–1007	3E8–3EF	2	Relay Element Status Row 125	
1008–1015	3F0–3F7	2	Relay Element Status Row 126	
1016–1023	3F8–3FF	2	Relay Element Status Row 127	
1024–1031	400–407	2	Relay Element Status Row 128	
1032–1039	408–40F	2	Relay Element Status Row 129	
1040–1047	410–417	2	Relay Element Status Row 130	
1048–1055	418–41F	2	Relay Element Status Row 131	
1056–1063	420–427	2	Relay Element Status Row 132	
1064–1071	428–42F	2	Relay Element Status Row 133	
1072–1079	430–437	2	Relay Element Status Row 134	
1080–1087	438–43F	2	Relay Element Status Row 135	

[a] See Appendix F: Relay Word Bits for relay element row numbers and definitions.

The relay responses to errors in the query are shown in *Table K.8*.

Table K.8   Responses to 02h Read Input Query Errors

Error	Error Code Returned	Communication Counter Increments
Invalid bit to read	Illegal Data Address (02h)	Invalid Address
Invalid number of bits to read	Illegal Data Value (03h)	Illegal Register
Format error	Illegal Data Value (03h)	Bad Packet Format

03h Read Holding Register Command

Use function code 03h to read directly from the Modbus Register Map shown in *Table K.23*. Use the **SET M** command (see *User-Defined Modbus Data Region and SET M Command on page K.19*) to configure the map with the register label names shown in *Table K.22*. You can read a maximum of 125 registers at once with this function code.

Table K.9   03h Read Holding Register Command (Sheet 1 of 2)

Bytes	Field
Requests from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (03h)
2 bytes	Starting Register Address
2 bytes	Number of Registers to Read
2 bytes	CRC-16
A successful response from the slave will have the following format:	
1 byte	Slave Address
1 byte	Function Code (03h)
1 byte	Bytes of data (*n*)

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Table K.9   03h Read Holding Register Command (Sheet 2 of 2)

Bytes	Field
n bytes	Data (2–250)
2 bytes	CRC-16

The relay responses to errors in the query are shown in *Table K.10*.

Table K.10   Responses to 03h Read Holding Register Query Errors

Error	Error Code Returned	Communication Counter Increments
Illegal register to read	Illegal Data Address (02h)	Invalid Address
Illegal number of registers to read	Illegal Data Value (03h)	Illegal Register
Format error	Illegal Data Value (03h)	Bad Packet Format

04h Read Input Register Command

Use function code 04h to read directly from the Modbus Register Map shown in *Table K.23*. Use the **SET M** command (see *User-Defined Modbus Data Region and SET M Command on page K.19*) to configure the map with the register label names shown in *Table K.22*. You can read a maximum of 125 registers at once with this function code.

Table K.11   04h Read Input Register Command

Bytes	Field
Requests from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (04h)
2 bytes	Starting Register Address
2 bytes	Number of Registers to Read
2 bytes	CRC-16
A successful response from the slave will have the following format:	
1 byte	Slave Address
1 byte	Function Code (04h)
1 byte	Bytes of data (*n*)
n bytes	Data (2–250)
2 bytes	CRC-16

The relay responses to errors in the query are shown in *Table K.12*.

Table K.12   Responses to 04h Read Input Register Query Errors

Error	Error Code Returned	Communication Counter Increments
Illegal register to read	Illegal Data Address (02h)	Invalid Address
Illegal number of registers to read	Illegal Data Value (03h)	Illegal Register
Format error	Illegal Data Value (03h)	Bad Packet Format

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05h Force Single Coil Command

Use function code 05h to set or clear a coil. The command response is identical to the command request shown in *Table K.13*.

Table K.13   05h Force Single Coil Command

Bytes	Field
Requests from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (05h)
2 bytes	Coil Reference
1 byte	Operation Code (FF for bit set, 00 for bit clear)
1 byte	Placeholder (00)
2 bytes	CRC-16

Table K.14 lists the coil numbers supported by the SEL-651R-2. The physical coils (coils 00–13) are self-resetting. Pulsing a Set remote bit (decimal address 80–111) causes the remote bit to be cleared at the end of the pulse.

Table K.14   01h, 05h SEL-651R-2 Output Coils (Sheet 1 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
0	0	1, 5	OUT101[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
1	1	1, 5	OUT102[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
2	2	1, 5	OUT103[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
3	3	1, 5	OUT104[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
4	4	1, 5	OUT105[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
5	5	1, 5	OUT106[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
6	6	1, 5	OUT107[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
7	7	1, 5	OUT108[a]	Pulse	1 second	Supported in models ordered with extra I/O, otherwise reserved
8	8	1, 5	Reserved			
9	9	1, 5	Reserved			
10	A	1, 5	Reserved			
11	B	1, 5	Reserved			
12	C	1, 5	OUT201[a]	Pulse	1 second	
13	D	1, 5	OUT202[a]	Pulse	1 second	
14	E	1, 5	Reserved			
15	F	1, 5	Reserved			
16	10	1, 5	Reserved			

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Table K.14   O1h, O5h SEL-651R-2 Output Coils (Sheet 2 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
17	11	1, 5	Reserved			
18	12	1, 5	Reserved			
19	13	1, 5	Reserved			
20	14	1, 5	Reserved			
21	15	1, 5	Reserved			
22	16	1, 5	Reserved			
23	17	1, 5	Reserved			
24	18	1, 5	Reserved			
25	19	1, 5	Reserved			
26	1A	1, 5	Reserved			
27	1B	1, 5	Reserved			
28	1C	1, 5	Reserved			
29	1D	1, 5	Reserved			
30	1E	1, 5	Reserved			
31	1F	1, 5	Reserved			
32	20	1, 5	Reserved			
33	21	1, 5	Reserved			
34	22	1, 5	Reserved			
35	23	1, 5	Reserved			
36	24	1, 5	Reserved			
37	25	1, 5	Reserved			
38	26	1, 5	Reserved			
39	27	1, 5	Reserved			
40	28	1, 5	Reserved			
41	29	1, 5	Reserved			
42	2A	1, 5	Reserved			
43	2B	1, 5	Reserved			
44	2C	1, 5	Reserved			
45	2D	1, 5	Reserved			
46	2E	1, 5	Reserved			
47	2F	1, 5	Reserved			
48	30	1, 5	RB01	Set/Clear		
49	31	1, 5	RB02	Set/Clear		

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Table K.14 01h, 05h SEL-651R-2 Output Coils (Sheet 3 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
50	32	1, 5	RB03	Set/Clear		
51	33	1, 5	RB04	Set/Clear		
52	34	1, 5	RB05	Set/Clear		
53	35	1, 5	RB06	Set/Clear		
54	36	1, 5	RB07	Set/Clear		
55	37	1, 5	RB08	Set/Clear		
56	38	1, 5	RB09	Set/Clear		
57	39	1, 5	RB10	Set/Clear		
58	3A	1, 5	RB11	Set/Clear		
59	3B	1, 5	RB12	Set/Clear		
60	3C	1, 5	RB13	Set/Clear		
61	3D	1, 5	RB14	Set/Clear		
62	3E	1, 5	RB15	Set/Clear		
63	3F	1, 5	RB16	Set/Clear		
64	40	1, 5	RB17	Set/Clear		
65	41	1, 5	RB18	Set/Clear		
66	42	1, 5	RB19	Set/Clear		
67	43	1, 5	RB20	Set/Clear		
68	44	1, 5	RB21	Set/Clear		
69	45	1, 5	RB22	Set/Clear		
70	46	1, 5	RB23	Set/Clear		
71	47	1, 5	RB24	Set/Clear		
72	48	1, 5	RB25	Set/Clear		
73	49	1, 5	RB26	Set/Clear		
74	4A	1, 5	RB27	Set/Clear		
75	4B	1, 5	RB28	Set/Clear		
76	4C	1, 5	RB29	Set/Clear		
77	4D	1, 5	RB30	Set/Clear		
78	4E	1, 5	RB31	Set/Clear		
79	4F	1, 5	RB32	Set/Clear		
80	50	1, 5	RB01	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.

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Table K.14 01h, 05h SEL-651R-2 Output Coils (Sheet 4 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
81	51	1, 5	RB02	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
82	52	1, 5	RB03	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
83	53	1, 5	RB04	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
84	54	1, 5	RB05	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
85	55	1, 5	RB06	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
86	56	1, 5	RB07	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
87	57	1, 5	RB08	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
88	58	1, 5	RB09	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
89	59	1, 5	RB10	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
90	5A	1, 5	RB11	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
91	5B	1, 5	RB12	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
92	5C	1, 5	RB13	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
93	5D	1, 5	RB14	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
94	5E	1, 5	RB15	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
95	5F	1, 5	RB16	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
96	60	1, 5	RB17	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.

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Table K.14 01h, 05h SEL-651R-2 Output Coils (Sheet 5 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
97	61	1, 5	RB18	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
98	62	1, 5	RB19	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
99	63	1, 5	RB20	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
100	64	1, 5	RB21	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
101	65	1, 5	RB22	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
102	66	1, 5	RB23	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
103	67	1, 5	RB24	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
104	68	1, 5	RB25	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
105	69	1, 5	RB26	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
106	6A	1, 5	RB27	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
107	6B	1, 5	RB28	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
108	6C	1, 5	RB29	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
109	6D	1, 5	RB30	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
110	6E	1, 5	RB31	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
111	6F	1, 5	RB32	Pulse	1 SELOGIC Processing Interval	Pulsing a Set remote bit will cause the remote bit to be cleared at the end of the pulse.
112	70	1, 5	Reserved			
113	71	1, 5	Reserved			

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Table K.14   01h, 05h SEL-651R-2 Output Coils (Sheet 6 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
114	72	1, 5	Reserved			
115	73	1, 5	Reserved			
116	74	1, 5	Breaker Open, Three-Phase (Relay Word bit OC3)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
117	75	1, 5	Breaker Close, Three-Phase (Relay Word bit CC3)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
118	76	1, 5	Breaker Open, Phase A (Relay Word bit OCA)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
119	77	1, 5	Breaker Close, Phase A (Relay Word bit CCA)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
120	78	1, 5	Breaker Open, Phase B (Relay Word bit OCB)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
121	79	1, 5	Breaker Close, Phase B (Relay Word bit CCB)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
122	7A	1, 5	Breaker Open, Phase C (Relay Word bit OCC)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
123	7B	1, 5	Breaker Close, Phase C (Relay Word bit CCC)	Pulse	1 SELOGIC Processing Interval	If the relay is disabled or the breaker control jumper is removed, the relay returns an error code 06 (Slave Device Busy).
124	7C	1, 5	Reserved			
125	7D	1, 5	Reserved			
126	7E	1, 5	Target Reset	Pulse		
127	7F	1, 5	Reset Demands	Pulse		
128	80	1, 5	Reset Peak Demand	Pulse		
129	81	1, 5	Reset Energy Data	Pulse		
130	82	1, 5	Reset Breaker Monitor	Pulse		
131	83	1, 5	Reset Min/Max	Pulse		
132	84	1, 5	Reset Event History	Pulse		
133	85	1, 5	Reset Hardware Alarm	Pulse		

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Table K.14   01h, 05h SEL-651R-2 Output Coils (Sheet 7 of 7)

Coil Address in Decimal	Coil Address in Hex	Function Code Supported	Coil Description	Coil Function	Duration	Notes
134	86	1, 5	Reserved			
135	87	1, 5	Reserved			

ᵃ Output coil pulsing of physical coils is intended only for low-level testing when the recloser control is out of service. For permanent control, use a remote bit in the appropriate SELᴏɢɪᴄ control equation.

Coil addresses start at 0000. If a function code 05 operation to coils 116 (OC3), 117 (CC3), 118 (OCA), 119 (CCA), 120 (OCB), 121 (CCB), 122 (OCC), or 123 (CCC) is attempted and the breaker jumper is not installed, the device will respond with Error Code 6. If the device is disabled, a function code 05 to any coil will respond with Error Code 4 (Device Error). In addition to Error Code 4, the device responses to errors in the query are shown in *Table K.15*.

Table K.15   Responses to 05h Force Single Coil Query Errors

Error	Error Code Returned	Communication Counter Increments
Invalid bit (coil)	Illegal Data Address (02h)	Invalid Address
Invalid bit state requested	Illegal Data Value (03h)	Illegal Register
Format Error	Illegal Data Value (03h)	Bad Packet Format

06h Preset Single Register Command

The SEL-651R-2 uses this function to allow a Modbus master to write directly to a database register. Refer to the Modbus Quantities Table in *Table K.22* for a list of registers that can be written by using this function code.

The command response is identical to the command request shown in *Table K.16*.

Table K.16   06h Preset Single Register Command

Bytes	Field
Queries from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (06h)
2 bytes	Register Address
2 bytes	Data
2 bytes	CRC-16

The relay responses to errors in the query are shown in *Table K.17*.

Table K.17   Responses to 06h Preset Single Register Query Errors

Error	Error Code Returned	Communication Counter Increments
Illegal register address	Illegal Data Address (02h)	Invalid Address Illegal Write
Illegal register value	Illegal Data Value (03h)	Illegal Write
Format error	Illegal Data Value (03h)	Bad Packet Format

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08h Loopback Diagnostic Command

The SEL-651R-2 uses this function to allow a Modbus master to perform a diagnostic test on the Modbus communications channel and relay. When the subfunction field is 0000h, the relay returns a replica of the received message.

Table K.18   08h Loopback Diagnostic Command

Bytes	Field
Requests from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (08h)
2 bytes	Subfunction (0000h)
2 bytes	Data Field
2 bytes	CRC-16
A successful response from the slave will have the following format:	
1 byte	Slave Address
1 byte	Function Code (08h)
2 bytes	Subfunction (0000h)
2 bytes	Data Field (identical to data in Master request)
2 bytes	CRC-16

The relay responses to errors in the query are shown in *Table K.19*.

Table K.19   Responses to 08h Loopback Diagnostic Query Errors

Error	Error Code Returned	Communication Counter Increments
Illegal subfunction code	Illegal Data Value (03h)	Illegal Function Code/Op Code
Format error	Illegal Data Value (03h)	Bad Packet Format

10h Preset Multiple Registers Command

This function code works much like code 06h, except that it allows you to write multiple registers at once.

Table K.20   10h Preset Multiple Registers Command (Sheet 1 of 2)

Bytes	Field
Queries from the master must have the following format:	
1 byte	Slave Address
1 byte	Function Code (10h)
2 bytes	Starting Address
2 bytes	Number of Registers to Write
1 byte	Number of Bytes of Data (*n*)
n bytes	Data
2 bytes	CRC-16
A successful response from the slave will have the following format:	
1 byte	Slave Address
1 byte	Function Code (10h)
2 bytes	Starting Address

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Table K.20 10h Preset Multiple Registers Command (Sheet 2 of 2)

Bytes	Field
2 bytes	Number of Registers
2 bytes	CRC-16

The relay responses to errors in the query are shown below.

Table K.21 10h Preset Multiple Registers Query Error Messages

Error	Error Code Returned	Communication Counter Increments
Illegal register to set	Illegal Data Address (02h)	Invalid Address Illegal Write
Illegal number of registers to set	Illegal Data Value (03h)	Illegal Register Illegal Write
Incorrect number of bytes in query data region	Illegal Data Value (03h)	Bad Packet Format Illegal Write
Invalid register data value	Illegal Data Value (03h)	Illegal Write

Bit Operations Using Function Codes 06h and 10h

The SEL-651R-2 includes registers for controlling some of the outputs. See LOG_CMD and RSTDAT in *Table K.22*. Use Modbus function codes 06h or 10h to write appropriate flags. Remember that when writing to the Logic command register with output contacts, it is not a bit operation. All the bits in that register need to be written together to reflect the state you want for each of the outputs.

User-Defined Modbus Data Region and SET M Command

The SEL-651R-2 Modbus Register Map defines an area of 250 contiguous addresses whose contents are defined by user-settable labels. This feature allows you to take 250 discrete values from anywhere in the Modbus Quantities Table (see *Table K.22*) and place them in contiguous registers that you can then read in a single command. Use the SEL ASCII command **SET M** (or the Modbus User Map settings in ACSELERATOR QuickSet SEL-5030 software) to define the user map addresses. A default map is provided with the relay. If the default Modbus map is not appropriate or more data are desired, edit the map as required for your application.

To use the user-defined data region, follow the steps listed below.

Step 1. Define the list of desired quantities (as many as 250). Arrange the quantities in any order that is convenient for you to use.

Step 2. Refer to *Table K.22* for a list of the Modbus labels for each quantity.

Step 3. Use the **SET M** command from the command line or QuickSet Modbus User Map to map user registers 001 to 250 (MOD_001 to MOD_250) using the labels in *Table K.22*.

Step 4. Use Modbus function code 03h or 04h to read the desired quantities from addresses 0–249 (decimal).

Note that the Modbus addresses begin with zero, which corresponds to Set M setting MOD_001.

As each label is entered in a register via the **SET M** command, the relay will increment to the next valid register.

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If a label is entered for a 32-bit quantity register (e.g., VAY, VBY, VCY, KW3), the relay will automatically skip a register in the sequence because two registers are required for the 32-bit quantity. The register with the lower index is the most significant word and the register with the higher index is the least significant word in the 32-bit quantity. In the following example, MOD_015 was previously set to 3I2, which is a 16-bit value and consumes one register. By changing the register label to KW3, a 32-bit value, the next register shown available for setting is MOD_017.

```
=>>SET M MOD_015 <Enter>

Modbus Map, Section 1:
USER REG#015
MOD_015 := 3I2
       ? KW3

USER REG#017
MOD_017 := VAY
      ?

USER REG#019
MOD_019 := VAYFA
       ?
=>>
```

Similarly, in this example, MOD_017 was previously set to VAY, which is a 32-bit value and consumes two registers. By changing the register label to IA, a 16-bit value, the next register shown available for setting is MOD_018. Because MOD_018 was previously not available, as it was the second register used for MOD_017 (VAY), there is no label assigned to it and it shows NA.

```
=>>SET M MOD_017 <Enter>

Modbus Map, Section 1:
USER REG#017
MOD_017 := VAY
      ? IA

USER REG#018
MOD_018 := NA
      ? IAFA

USER REG#019
MOD_019 := VAYFA
      ? IB
=>>
```

5- or 6-Digit Master Addresses

If your master uses 5- or 6-digit address references, add the appropriate number to the Modbus data register address, provided in *Table K.23*, when configuring your master. For example, if your master uses 5-digit addressing, add 40001 for holding register operations. For input register functions, add 30001. If your master uses 6-digit addressing, add 400001 for holding register operations or 300001 for input register functions. The actual address that appears in the address field of the message will be the address shown in *Table K.23*. For example, MOD_001 is address 0000 (see *Table K.23* for Modbus register addresses). A master using 6-digit addresses to read a holding register may be configured for address 400001. However, the data address field of the message from the master will contain address 0000.

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Table K.22   Modbus Quantities Table (Sheet 1 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Special Quantities						
CONSTANT VALUE = 0		0	1	0	0	
CONSTANT VALUE = 1		1	1	1	1	
NO OPERATION		NOOP	1	0	0	
NOT ASSIGNED		NA	1	0	0	
Reset Bits						
Reset Data	03, 04, 06, 10h	**RSTDAT**	1	0	65535	
Reset Targets		**Bit 0**				
Reserved		**Bit 1**				
Reserved		**Bit 2**				
Reset History Data		**Bit 3**				
Reset Comm Counters		**Bit 4**				
Reset Breaker Monitor		**Bit 5**				
Reset Energy Data		**Bit 6**				
Reset Max/min Data		**Bit 7**				
Reset Demands		**Bit 8**				
Reset Peak Demand		**Bit 9**				
Reset HALARM		**Bit 10**				
Reserved		**Bits 11–15**				
Date/Time Set						
Set Seconds	03, 04, 06, 10h	**TIME_S**	1	0	59999	1000
Set Minutes	03, 04, 06, 10h	**TIME_M**	1	0	59	
Set Hour	03, 04, 06, 10h	**TIME_H**	1	0	23	
Set Day	03, 04, 06, 10h	**DATE_D**	1	1	31	
Set Month	03, 04, 06, 10h	**DATE_M**	1	1	12	
Set Year	03, 04, 06, 10h	**DATE_Y**	1	2000	2090	
Historical Data						
No. of Event Logs	03, 04	NUMEVE	1	0		
Event Selected	03, 04, 06, 10h	**EVESEL**	1	0		
Fault Time Second	03, 04	**FTIME_S**	1	0	59999	1000
Fault Time Minute	03, 04	**FTIME_M**	1	0	59	
Fault Time Hour	03, 04	**FTIME_H**	1	0	23	
Fault Time Day	03, 04	**FDATE_D**	1	1	31	
Fault Time Month	03, 04	**FDATE_M**	1	1	12	

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Table K.22 Modbus Quantities Table (Sheet 2 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Fault Time Year	03, 04	**FDATE_Y**	1	0	9999	
Event Type	03, 04	**EVE_TYPE**	1	0	65535 (see *Table 12.2*)	
3 = AB Fault Trip						
5 = CA Fault Trip						
6 = BC Fault Trip						
7 = ABC Fault Trip						
9 = AG Fault Trip						
10 = BG Fault Trip						
11 = ABG Fault Trip						
12 = CG Fault Trip						
13 = CAG Fault Trip						
14 = BCG Fault Trip						
16 = Trigger						
32 = Pulse						
64 = Trip						
128 = ER Trigger						
Fault Location	03, 04	**FLOC**[c]	1	–32768	32767	100
Fault Current	03, 04	**FI**	1	0	65535	
Phase A Fault Current	03, 04	**FIA**	1	0	65535	
Phase B Fault Current	03, 04	**FIB**	1	0	65535	
Phase C Fault Current	03, 04	**FIC**	1	0	65535	
Ground Fault Current	03, 04	**FIG**	1	0	65535	
Neg.-Seq. Fault Current	03, 04	**FIQ**	1	0	65535	
Fault Frequency	03, 04	**FFREQ**	1	4000	7000	100
Fault Group	03, 04	**FGRP**	1	1	8	
Fault Shot Count	03, 04	**FSHO**	1	0	4	
Fault Targets High[d] (Upper 16 Bits)	03, 04	**FTARHI**	1	0	65535	
Fault Targets Low[d] (Lower 16 Bits)	03, 04	**FTARLO**	1	0	65535	
Control I/O Commands						
Logic Command[e]	03, 04, 06, 10h	LOG_CMD	1	0	2	
Breaker Close—3 Phase (Relay Word bit CC3)		Bit 0				
Breaker Open—3 Phase (Relay Word bit OC3)		Bit 1				
Reserved		Bits 2–15				
Current Data						
Phase A Current Mag.	03, 04	IA	1	0	65535	
Phase A Current Ang.	03, 04	IAFA	1	–18000	18000	100
Phase B Current Mag.	03, 04	IB	1	0	65535	
Phase B Current Ang.	03, 04	IBFA	1	–18000	18000	100

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Table K.22   Modbus Quantities Table (Sheet 3 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase C Current Mag.	03, 04	IC	1	0	65535	
Phase C Current Ang.	03, 04	ICFA	1	−18000	18000	100
Neutral Current Mag.	03, 04	IN	1	0	65535	
Neutral Current Ang.	03, 04	INFA	1	−18000	18000	100
Residual Ground Current Mag.	03, 04	IG	1	0	65535	
Residual Ground Current Ang.	03, 04	IGFA	1	−18000	18000	100
3I0 Current Mag.	03, 04	3I0	1	0	65535	
3I0 Current Ang.	03, 04	3I0FA	1	−18000	18000	100
Positive-Seq. Current Mag.	03, 04	I1	1	0	65535	
Positive-Seq. Current Ang.	03, 04	I1FA	1	−18000	18000	100
Negative-Seq. Current Mag.	03, 04	3I2	1	0	65535	
Negative-Seq. Current Ang.	03, 04	3I2FA	1	−18000	18000	100
Voltage and Frequency Data						
Frequency	03, 04	FREQ	1	4000	7000	100
Phase A Y-Terminal Voltage Mag.	03, 04	VAY	2	0	4294967295	
Phase A Y-Terminal Voltage Ang.	03, 04	VAYFA	1	−18000	18000	100
Phase B Y-Terminal Voltage Mag.	03, 04	VBY	2	0	4294967295	
Phase B Y-Terminal Voltage Ang.	03, 04	VBYFA	1	−18000	18000	100
Phase C Y-Terminal Voltage Mag.	03, 04	VCY	2	0	4294967295	
Phase C Y-Terminal Voltage Ang.	03, 04	VCYFA	1	−18000	18000	100
Phase A Z-Terminal Voltage Mag.	03, 04	VAZ	2	0	4294967295	
Phase A Z-Terminal Voltage Ang.	03, 04	VAZFA	1	−18000	18000	100
Phase B Z-Terminal Voltage Mag.	03, 04	VBZ	2	0	4294967295	
Phase B Z-Terminal Voltage Ang.	03, 04	VBZFA	1	−18000	18000	100
Phase C Z-Terminal Voltage Mag.	03, 04	VCZ	2	0	4294967295	
Phase C Z-Terminal Voltage Ang.	03, 04	VCZFA	1	−18000	18000	100
Phase AB Y-Terminal Voltage Mag.	03, 04	VABY	2	0	4294967295	
Phase AB Y-Terminal Voltage Ang.	03, 04	VABYFA	1	−18000	18000	100
Phase BC Y-Terminal Voltage Mag.	03, 04	VBCY	2	0	4294967295	
Phase BC Y-Terminal Voltage Ang.	03, 04	VBCYFA	1	−18000	18000	100
Phase CA Y-Terminal Voltage Mag.	03, 04	VCAY	2	0	4294967295	
Phase CA Y-Terminal Voltage Ang.	03, 04	VCAYFA	1	−18000	18000	100
Phase AB Z-Terminal Voltage Mag.	03, 04	VABZ	2	0	4294967295	
Phase AB Z-Terminal Voltage Ang.	03, 04	VABZFA	1	−18000	18000	100
Phase BC Z-Terminal Voltage Mag.	03, 04	VBCZ	2	0	4294967295	
Phase BC Z-Terminal Voltage Ang.	03, 04	VBCZFA	1	−18000	18000	100
Phase CA Z-Terminal Voltage Mag.	03, 04	VCAZ	2	0	4294967295	
Phase CA Z-Terminal Voltage Ang.	03, 04	VCAZFA	1	−18000	18000	100
Pos.-Seq. Y-Terminal Voltage Mag.	03, 04	V1Y	2	0	4294967295	
Pos.-Seq. Y-Terminal Voltage Ang.	03, 04	V1YFA	1	−18000	18000	100

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Table K.22   Modbus Quantities Table (Sheet 4 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Neg.-Seq. Y-Terminal Voltage Mag.	03, 04	V2Y	2	0	4294967295	
Neg.-Seq. Y-Terminal Voltage Ang.	03, 04	V2YFA	1	–18000	18000	100
3V0 Y-Terminal Voltage Mag.	03, 04	3V0Y	2	0	4294967295	
3V0 Y-Terminal Voltage Ang.	03, 04	3V0YFA	1	–18000	18000	100
Pos.-Seq. Z-Terminal Voltage Mag.	03, 04	V1Z	2	0	4294967295	
Pos.-Seq. Z-Terminal Voltage Ang.	03, 04	V1ZFA	1	–18000	18000	100
Neg.-Seq. Z-Terminal Voltage Mag.	03, 04	V2Z	2	0	4294967295	
Neg.-Seq. Z-Terminal Voltage Ang.	03, 04	V2ZFA	1	–18000	18000	100
3V0 Z-Terminal Voltage Mag.	03, 04	3V0Z	2	0	4294967295	
3V0 Z-Terminal Voltage Ang.	03, 04	3V0ZFA	1	–18000	18000	100
Power Data						
Phase A Apparent Power	03, 04	KVAA	2	–2147483648	2147483647	
Phase B Apparent Power	03, 04	KVAB	2	–2147483648	2147483647	
Phase C Apparent Power	03, 04	KVAC	2	–2147483648	2147483647	
Three-phase Apparent Power	03, 04	KVA3	2	–2147483648	2147483647	
Phase A Real Power	03, 04	KWA	2	–2147483648	2147483647	
Phase B Real Power	03, 04	KWB	2	–2147483648	2147483647	
Phase C Real Power	03, 04	KWC	2	–2147483648	2147483647	
Three-phase Real Power	03, 04	KW3	2	–2147483648	2147483647	
Phase A Reactive Power	03, 04	KVARA	2	–2147483648	2147483647	
Phase B Reactive Power	03, 04	KVARB	2	–2147483648	2147483647	
Phase C Reactive Power	03, 04	KVARC	2	–2147483648	2147483647	
Three-phase Reactive Power	03, 04	KVAR3	2	–2147483648	2147483647	
Phase A Power Factor	03, 04	PFA	1	–100	100	100
Phase B Power Factor	03, 04	PFB	1	–100	100	100
Phase C Power Factor	03, 04	PFC	1	–100	100	100
Three-phase Power Factor	03, 04	PF3	1	–100	100	100
Phase A PF Leading 0 = LAG 1 = LEAD	03, 04	LDPFA	1	0	1	
Phase B PF Leading 0 = LAG 1 = LEAD	03, 04	LDPFB	1	0	1	
Phase C PF Leading 0 = LAG 1 = LEAD	03, 04	LDPFC	1	0	1	
Three-phase PF Leading 0 = LAG 1 = LEAD	03, 04	LDPF3	1	0	1	

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Table K.22   Modbus Quantities Table (Sheet 5 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Energy Data						
Phase A Real Energy IN	03, 04	MWHAI	2	–2147483648	2147483647	
Phase B Real Energy IN	03, 04	MWHBI	2	–2147483648	2147483647	
Phase C Real Energy IN	03, 04	MWHCI	2	–2147483648	2147483647	
Three-phase Real Energy IN	03, 04	MWH3I	2	–2147483648	2147483647	
Phase A Real Energy OUT	03, 04	MWHAO	2	–2147483648	2147483647	
Phase B Real Energy OUT	03, 04	MWHBO	2	–2147483648	2147483647	
Phase C Real Energy OUT	03, 04	MWHCO	2	–2147483648	2147483647	
Three-phase Real Energy OUT	03, 04	MWH3O	2	–2147483648	2147483647	
Phase A Reactive Energy IN	03, 04	MVRHAI	2	–2147483648	2147483647	
Phase B Reactive Energy IN	03, 04	MVRHBI	2	–2147483648	2147483647	
Phase C Reactive Energy IN	03, 04	MVRHCI	2	–2147483648	2147483647	
Three-phase Reactive Energy IN	03, 04	MVRH3I	2	–2147483648	2147483647	
Phase A Reactive Energy OUT	03, 04	MVRHAO	2	–2147483648	2147483647	
Phase B Reactive Energy OUT	03, 04	MVRHBO	2	–2147483648	2147483647	
Phase C Reactive Energy OUT	03, 04	MVRHCO	2	–2147483648	2147483647	
Three-phase Reactive Energy OUT	03, 04	MVRH3O	2	–2147483648	2147483647	
Demand Data						
Phase A Demand Current	03, 04	IADEM	1	0	65535	
Phase B Demand Current	03, 04	IBDEM	1	0	65535	
Phase C Demand Current	03, 04	ICDEM	1	0	65535	
Neutral Demand Current	03, 04	INDEM	1	0	65535	
Residual Ground Demand Current	03, 04	IGDEM	1	0	65535	
Neg.-Seq. Demand Current	03, 04	3I2DEM	1	0	65535	
Phase A Apparent Power Demand	03, 04	KVAAD	2	–2147483648	2147483647	
Phase B Apparent Power Demand	03, 04	KVABD	2	–2147483648	2147483647	
Phase C Apparent Power Demand	03, 04	KVACD	2	–2147483648	2147483647	
Three-phase Apparent Power Demand	03, 04	KVA3D	2	–2147483648	2147483647	
Phase A Real Power Demand IN	03, 04	KWADI	2	–2147483648	2147483647	
Phase B Real Power Demand IN	03, 04	KWBDI	2	–2147483648	2147483647	
Phase C Real Power Demand IN	03, 04	KWCDI	2	–2147483648	2147483647	
Three-phase Real Power Demand IN	03, 04	KW3DI	2	–2147483648	2147483647	
Phase A Reactive Power Demand IN	03, 04	KVRADI	2	–2147483648	2147483647	
Phase B Reactive Power Demand IN	03, 04	KVRBDI	2	–2147483648	2147483647	
Phase C Reactive Power Demand IN	03, 04	KVRCDI	2	–2147483648	2147483647	
Three-phase Reactive Power Demand IN	03, 04	KVR3DI	2	–2147483648	2147483647	
Phase A Real Power Demand OUT	03, 04	KWADO	2	–2147483648	2147483647	
Phase B Real Power Demand OUT	03, 04	KWBDO	2	–2147483648	2147483647	
Phase C Real Power Demand OUT	03, 04	KWCDO	2	–2147483648	2147483647	
Three-phase Real Power Demand OUT	03, 04	KW3DO	2	–2147483648	2147483647	

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Table K.22   Modbus Quantities Table (Sheet 6 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase A Reactive Power Demand OUT	03, 04	KVRADO	2	–2147483648	2147483647	
Phase B Reactive Power Demand OUT	03, 04	KVRBDO	2	–2147483648	2147483647	
Phase C Reactive Power Demand OUT	03, 04	KVRCDO	2	–2147483648	2147483647	
Three-phase Reactive Power Demand OUT	03, 04	KVR3DO	2	–2147483648	2147483647	
Phase A Peak Demand Current	03, 04	IAPK	1	0	65535	
Phase B Peak Demand Current	03, 04	IBPK	1	0	65535	
Phase C Peak Demand Current	03, 04	ICPK	1	0	65535	
Neutral Peak Demand Current	03, 04	INPK	1	0	65535	
Residual Ground Peak Demand Current	03, 04	IGPK	1	0	65535	
Neg.-Seq. Peak Demand Current	03, 04	3I2PK	1	0	65535	
Phase A Apparent Power Peak Demand	03, 04	KVAAP	2	–2147483648	2147483647	
Phase B Apparent Power Peak Demand	03, 04	KVABP	2	–2147483648	2147483647	
Phase C Apparent Power Peak Demand	03, 04	KVACP	2	–2147483648	2147483647	
3Phase Apparent Power Peak Demand	03, 04	KVA3P	2	–2147483648	2147483647	
Phase A Real Power Peak Demand IN	03, 04	KWAPI	2	–2147483648	2147483647	
Phase B Real Power Peak Demand IN	03, 04	KWBPI	2	–2147483648	2147483647	
Phase C Real Power Peak Demand IN	03, 04	KWCPI	2	–2147483648	2147483647	
Three-phase Real Power Peak Demand IN	03, 04	KW3PI	2	–2147483648	2147483647	
Phase A Reactive Power Peak Demand IN	03, 04	KVRAPI	2	–2147483648	2147483647	
Phase B Reactive Power Peak Demand IN	03, 04	KVRBPI	2	–2147483648	2147483647	
Phase C Reactive Power Peak Demand IN	03, 04	KVRCPI	2	–2147483648	2147483647	
Three-phase Reactive Power Peak Demand IN	03, 04	KVR3PI	2	–2147483648	2147483647	
Phase A Real Power Peak Demand OUT	03, 04	KWAPO	2	–2147483648	2147483647	
Phase B Real Power Peak Demand OUT	03, 04	KWBPO	2	–2147483648	2147483647	
Phase C Real Power Peak Demand OUT	03, 04	KWCPO	2	–2147483648	2147483647	
Three-phase Real Power Peak Demand OUT	03, 04	KW3PO	2	–2147483648	2147483647	
Phase A Reactive Power Peak Demand OUT	03, 04	KVRAPO	2	–2147483648	2147483647	
Phase B Reactive Power Peak Demand OUT	03, 04	KVRBPO	2	–2147483648	2147483647	
Phase C Reactive Power Peak Demand OUT	03, 04	KVRCPO	2	–2147483648	2147483647	
Three-phase Reactive Power Peak Demand OUT	03, 04	KVR3PO	2	–2147483648	2147483647	
Max/Min Metering Data						
Phase A Current Max Mag.	03, 04	IAMAX[f]	1	0	65535	
Phase A Current Max Time Seconds	03, 04	IAMXT_S	1	0	59999	1000
Phase A Current Max Time Minutes	03, 04	IAMXT_M	1	0	59	
Phase A Current Max Time Hour	03, 04	IAMXT_H	1	0	23	
Phase A Current Max Date Day	03, 04	IAMXD_D	1	0	31	
Phase A Current Max Date Month	03, 04	IAMXD_M	1	0	12	
Phase A Current Max Date Year	03, 04	IAMXD_Y	1	0	9999	
Phase B Current Max Mag.	03, 04	IBMAX[f]	1	0	65535	

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Table K.22   Modbus Quantities Table (Sheet 7 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase B Current Max Time Seconds	03, 04	IBMXT_S	1	0	59999	1000
Phase B Current Max Time Minutes	03, 04	IBMXT_M	1	0	59	
Phase B Current Max Time Hour	03, 04	IBMXT_H	1	0	23	
Phase B Current Max Date Day	03, 04	IBMXD_D	1	0	31	
Phase B Current Max Date Month	03, 04	IBMXD_M	1	0	12	
Phase B Current Max Date Year	03, 04	IBMXD_Y	1	0	9999	
Phase C Current Max Mag.	03, 04	ICMAX[f]	1	0	65535	
Phase C Current Max Time Seconds	03, 04	ICMXT_S	1	0	59999	1000
Phase C Current Max Time Minutes	03, 04	ICMXT_M	1	0	59	
Phase C Current Max Time Hour	03, 04	ICMXT_H	1	0	23	
Phase C Current Max Date Day	03, 04	ICMXD_D	1	0	31	
Phase C Current Max Date Month	03, 04	ICMXD_M	1	0	12	
Phase C Current Max Date Year	03, 04	ICMXD_Y	1	0	9999	
Neutral Current Max Mag.	03, 04	INMAX[f]	1	0	65535	
Neutral Current Max Time Seconds	03, 04	INMXT_S	1	0	59999	1000
Neutral Current Max Time Minutes	03, 04	INMXT_M	1	0	59	
Neutral Current Max Time Hour	03, 04	INMXT_H	1	0	23	
Neutral Current Max Date Day	03, 04	INMXD_D	1	0	31	
Neutral Current Max Date Month	03, 04	INMXD_M	1	0	12	
Neutral Current Max Date Year	03, 04	INMXD_Y	1	0	9999	
Residual Ground Current Max Mag.	03, 04	IGMAX[f]	1	0	65535	
Residual Ground Current Max Time Seconds	03, 04	IGMXT_S	1	0	59999	1000
Residual Ground Current Max Time Minutes	03, 04	IGMXT_M	1	0	59	
Residual Ground Current Max Time Hour	03, 04	IGMXT_H	1	0	23	
Residual Ground Current Max Date Day	03, 04	IGMXD_D	1	0	31	
Residual Ground Current Max Date Month	03, 04	IGMXD_M	1	0	12	
Residual Ground Current Max Date Year	03, 04	IGMXD_Y	1	0	9999	
Phase A Current Min Mag.	03, 04	IAMIN[f]	1	0	65535	
Phase A Current Min Time Seconds	03, 04	IAMNT_S	1	0	59999	1000
Phase A Current Min Time Minutes	03, 04	IAMNT_M	1	0	59	
Phase A Current Min Time Hour	03, 04	IAMNT_H	1	0	23	
Phase A Current Min Date Day	03, 04	IAMND_D	1	0	31	
Phase A Current Min Date Month	03, 04	IAMND_M	1	0	12	
Phase A Current Min Date Year	03, 04	IAMND_Y	1	0	9999	
Phase B Current Min Mag.	03, 04	IBMIN[f]	1	0	65535	
Phase B Current Min Time Seconds	03, 04	IBMNT_S	1	0	59999	1000
Phase B Current Min Time Minutes	03, 04	IBMNT_M	1	0	59	
Phase B Current Min Time Hour	03, 04	IBMNT_H	1	0	23	
Phase B Current Min Date Day	03, 04	IBMND_D	1	0	31	
Phase B Current Min Date Month	03, 04	IBMND_M	1	0	12	

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Table K.22 Modbus Quantities Table (Sheet 8 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase B Current Min Date Year	03, 04	IBMND_Y	1	0	9999	
Phase C Current Min Mag.	03, 04	ICMIN[f]	1	0	65535	
Phase C Current Min Time Seconds	03, 04	ICMNT_S	1	0	59999	1000
Phase C Current Min Time Minutes	03, 04	ICMNT_M	1	0	59	
Phase C Current Min Time Hour	03, 04	ICMNT_H	1	0	23	
Phase C Current Min Date Day	03, 04	ICMND_D	1	0	31	
Phase C Current Min Date Month	03, 04	ICMND_M	1	0	12	
Phase C Current Min Date Year	03, 04	ICMND_Y	1	0	9999	
Neutral Current Min Mag.	03, 04	INMIN[f]	1	0	65535	
Neutral Current Min Time Seconds	03, 04	INMNT_S	1	0	59999	1000
Neutral Current Min Time Minutes	03, 04	INMNT_M	1	0	59	
Neutral Current Min Time Hour	03, 04	INMNT_H	1	0	23	
Neutral Current Min Date Day	03, 04	INMND_D	1	0	31	
Neutral Current Min Date Month	03, 04	INMND_M	1	0	12	
Neutral Current Min Date Year	03, 04	INMND_Y	1	0	9999	
Residual Ground Current Min Mag.	03, 04	IGMIN[f]	1	0	65535	
Residual Ground Current Min Time Seconds	03, 04	IGMNT_S	1	0	59999	1000
Residual Ground Current Min Time Minutes	03, 04	IGMNT_M	1	0	59	
Residual Ground Current Min Time Hour	03, 04	IGMNT_H	1	0	23	
Residual Ground Current Min Date Day	03, 04	IGMND_D	1	0	31	
Residual Ground Current Min Date Month	03, 04	IGMND_M	1	0	12	
Residual Ground Current Min Date Year	03, 04	IGMND_Y	1	0	9999	
Phase A Y-Terminal Voltage Max Mag.	03, 04	VAYMAX[f]	2	0	4294967295	
Phase A Y-Terminal Voltage Max Time Seconds	03, 04	VAYMXT_S	1	0	59999	1000
Phase A Y-Terminal Voltage Max Time Minutes	03, 04	VAYMXT_M	1	0	59	
Phase A Y-Terminal Voltage Max Time Hour	03, 04	VAYMXT_H	1	0	23	
Phase A Y-Terminal Voltage Max Date Day	03, 04	VAYMXD_D	1	0	31	
Phase A Y-Terminal Voltage Max Date Month	03, 04	VAYMXD_M	1	0	12	
Phase A Y-Terminal Voltage Max Date Year	03, 04	VAYMXD_Y	1	0	9999	
Phase B Y-Terminal Voltage Max Mag.	03, 04	VBYMAX[f]	2	0	4294967295	
Phase B Y-Terminal Voltage Max Time Seconds	03, 04	VBYMXT_S	1	0	59999	1000
Phase B Y-Terminal Voltage Max Time Minutes	03, 04	VBYMXT_M	1	0	59	
Phase B Y-Terminal Voltage Max Time Hour	03, 04	VBYMXT_H	1	0	23	
Phase B Y-Terminal Voltage Max Date Day	03, 04	VBYMXD_D	1	0	31	
Phase B Y-Terminal Voltage Max Date Month	03, 04	VBYMXD_M	1	0	12	
Phase B Y-Terminal Voltage Max Date Year	03, 04	VBYMXD_Y	1	0	9999	
Phase C Y-Terminal Voltage Max Mag.	03, 04	VCYMAX[f]	2	0	4294967295	
Phase C Y-Terminal Voltage Max Time Seconds	03, 04	VCYMXT_S	1	0	59999	1000
Phase C Y-Terminal Voltage Max Time Minutes	03, 04	VCYMXT_M	1	0	59	
Phase C Y-Terminal Voltage Max Time Hour	03, 04	VCYMXT_H	1	0	23	

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Table K.22 Modbus Quantities Table (Sheet 9 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase C Y-Terminal Voltage Max Date Day	03, 04	VCYMXD_D	1	0	31	
Phase C Y-Terminal Voltage Max Date Month	03, 04	VCYMXD_M	1	0	12	
Phase C Y-Terminal Voltage Max Date Year	03, 04	VCYMXD_Y	1	0	9999	
Phase A Z-Terminal Voltage Max Mag.	03, 04	VAZMAX[f]	2	0	4294967295	
Phase A Z-Terminal Voltage Max Time Seconds	03, 04	VAZMXT_S	1	0	59999	1000
Phase A Z-Terminal Voltage Max Time Minutes	03, 04	VAZMXT_M	1	0	59	
Phase A Z-Terminal Voltage Max Time Hour	03, 04	VAZMXT_H	1	0	23	
Phase A Z-Terminal Voltage Max Date Day	03, 04	VAZMXD_D	1	0	31	
Phase A Z-Terminal Voltage Max Date Month	03, 04	VAZMXD_M	1	0	12	
Phase A Z-Terminal Voltage Max Date Year	03, 04	VAZMXD_Y	1	0	9999	
Phase B Z-Terminal Voltage Max Mag.	03, 04	VBZMAX[f]	2	0	4294967295	
Phase B Z-Terminal Voltage Max Time Seconds	03, 04	VBZMXT_S	1	0	59999	1000
Phase B Z-Terminal Voltage Max Time Minutes	03, 04	VBZMXT_M	1	0	59	
Phase B Z-Terminal Voltage Max Time Hour	03, 04	VBZMXT_H	1	0	23	
Phase B Z-Terminal Voltage Max Date Day	03, 04	VBZMXD_D	1	0	31	
Phase B Z-Terminal Voltage Max Date Month	03, 04	VBZMXD_M	1	0	12	
Phase B Z-Terminal Voltage Max Date Year	03, 04	VBZMXD_Y	1	0	9999	
Phase C Z-Terminal Voltage Max Mag.	03, 04	VCZMAX[f]	2	0	4294967295	
Phase C Z-Terminal Voltage Max Time Seconds	03, 04	VCZMXT_S	1	0	59999	1000
Phase C Z-Terminal Voltage Max Time Minutes	03, 04	VCZMXT_M	1	0	59	
Phase C Z-Terminal Voltage Max Time Hour	03, 04	VCZMXT_H	1	0	23	
Phase C Z-Terminal Voltage Max Date Day	03, 04	VCZMXD_D	1	0	31	
Phase C Z-Terminal Voltage Max Date Month	03, 04	VCZMXD_M	1	0	12	
Phase C Z-Terminal Voltage Max Date Year	03, 04	VCZMXD_Y	1	0	9999	
Phase A Y-Terminal Voltage Min Mag.	03, 04	VAYMIN[f]	2	0	4294967295	
Phase A Y-Terminal Voltage Min Time Seconds	03, 04	VAYMNT_S	1	0	59999	1000
Phase A Y-Terminal Voltage Min Time Minutes	03, 04	VAYMNT_M	1	0	59	
Phase A Y-Terminal Voltage Min Time Hour	03, 04	VAYMNT_H	1	0	23	
Phase A Y-Terminal Voltage Min Date Day	03, 04	VAYMND_D	1	0	31	
Phase A Y-Terminal Voltage Min Date Month	03, 04	VAYMND_M	1	0	12	
Phase A Y-Terminal Voltage Min Date Year	03, 04	VAYMND_Y	1	0	9999	
Phase B Y-Terminal Voltage Min Mag.	03, 04	VBYMIN[f]	2	0	4294967295	
Phase B Y-Terminal Voltage Min Time Seconds	03, 04	VBYMNT_S	1	0	59999	1000
Phase B Y-Terminal Voltage Min Time Minutes	03, 04	VBYMNT_M	1	0	59	
Phase B Y-Terminal Voltage Min Time Hour	03, 04	VBYMNT_H	1	0	23	
Phase B Y-Terminal Voltage Min Date Day	03, 04	VBYMND_D	1	0	31	
Phase B Y-Terminal Voltage Min Date Month	03, 04	VBYMND_M	1	0	12	
Phase B Y-Terminal Voltage Min Date Year	03, 04	VBYMND_Y	1	0	9999	
Phase C Y-Terminal Voltage Min Mag.	03, 04	VCYMIN[f]	2	0	4294967295	
Phase C Y-Terminal Voltage Min Time Seconds	03, 04	VCYMNT_S	1	0	59999	1000

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Table K.22   Modbus Quantities Table (Sheet 10 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase C Y-Terminal Voltage Min Time Minutes	03, 04	VCYMNT_M	1	0	59	
Phase C Y-Terminal Voltage Min Time Hour	03, 04	VCYMNT_H	1	0	23	
Phase C Y-Terminal Voltage Min Date Day	03, 04	VCYMND_D	1	0	31	
Phase C Y-Terminal Voltage Min Date Month	03, 04	VCYMND_M	1	0	12	
Phase C Y-Terminal Voltage Min Date Year	03, 04	VCYMND_Y	1	0	9999	
Phase A Z-Terminal Voltage Min Mag.	03, 04	VAZMIN[f]	2	0	4294967295	
Phase A Z-Terminal Voltage Min Time Seconds	03, 04	VAZMNT_S	1	0	59999	1000
Phase A Z-Terminal Voltage Min Time Minutes	03, 04	VAZMNT_M	1	0	59	
Phase A Z-Terminal Voltage Min Time Hour	03, 04	VAZMNT_H	1	0	23	
Phase A Z-Terminal Voltage Min Date Day	03, 04	VAZMND_D	1	0	31	
Phase A Z-Terminal Voltage Min Date Month	03, 04	VAZMND_M	1	0	12	
Phase A Z-Terminal Voltage Min Date Year	03, 04	VAZMND_Y	1	0	9999	
Phase B Z-Terminal Voltage Min Mag.	03, 04	VBZMIN[f]	2	0	4294967295	
Phase B Z-Terminal Voltage Min Time Seconds	03, 04	VBZMNT_S	1	0	59999	1000
Phase B Z-Terminal Voltage Min Time Minutes	03, 04	VBZMNT_M	1	0	59	
Phase B Z-Terminal Voltage Min Time Hour	03, 04	VBZMNT_H	1	0	23	
Phase B Z-Terminal Voltage Min Date Day	03, 04	VBZMND_D	1	0	31	
Phase B Z-Terminal Voltage Min Date Month	03, 04	VBZMND_M	1	0	12	
Phase B Z-Terminal Voltage Min Date Year	03, 04	VBZMND_Y	1	0	9999	
Phase C Z-Terminal Voltage Min Mag.	03, 04	VCZMIN[f]	2	0	4294967295	
Phase C Z-Terminal Voltage Min Time Seconds	03, 04	VCZMNT_S	1	0	59999	1000
Phase C Z-Terminal Voltage Min Time Minutes	03, 04	VCZMNT_M	1	0	59	
Phase C Z-Terminal Voltage Min Time Hour	03, 04	VCZMNT_H	1	0	23	
Phase C Z-Terminal Voltage Min Date Day	03, 04	VCZMND_D	1	0	31	
Phase C Z-Terminal Voltage Min Date Month	03, 04	VCZMND_M	1	0	12	
Phase C Z-Terminal Voltage Min Date Year	03, 04	VCZMND_Y	1	0	9999	
Three-phase Apparent Power Max	03, 04	KVA3MAX[f]	2	–2147483648	2147483647	
Three-phase Apparent Power Max Time Seconds	03, 04	KVA3XT_S	1	0	59999	1000
Three-phase Apparent Power Max Time Minutes	03, 04	KVA3XT_M	1	0	59	
Three-phase Apparent Power Max Time Hour	03, 04	KVA3XT_H	1	0	23	
Three-phase Apparent Power Max Date Day	03, 04	KVA3XD_D	1	0	31	
Three-phase Apparent Power Max Date Month	03, 04	KVA3XD_M	1	0	12	
Three-phase Apparent Power Max Date Year	03, 04	KVA3XD_Y	1	0	9999	
Three-phase Real Power Max	03, 04	KW3MAX[f]	2	–2147483648	2147483647	
Three-phase Real Power Max Time Seconds	03, 04	KW3MXT_S	1	0	59999	1000
Three-phase Real Power Max Time Minutes	03, 04	KW3MXT_M	1	0	59	
Three-phase Real Power Max Time Hour	03, 04	KW3MXT_H	1	0	23	
Three-phase Real Power Max Date Day	03, 04	KW3MXD_D	1	0	31	
Three-phase Real Power Max Date Month	03, 04	KW3MXD_M	1	0	12	
Three-phase Real Power Max Date Year	03, 04	KW3MXD_Y	1	0	9999	

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Table K.22 Modbus Quantities Table (Sheet 11 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Three-phase Reactive Power Max	03, 04	KVR3MAX[f]	2	–2147483648	2147483647	
Three-phase Reactive Power Max Time Seconds	03, 04	KVR3XT_S	1	0	59999	1000
Three-phase Reactive Power Max Time Minutes	03, 04	KVR3XT_M	1	0	59	
Three-phase Reactive Power Max Time Hour	03, 04	KVR3XT_H	1	0	23	
Three-phase Reactive Power Max Date Day	03, 04	KVR3XD_D	1	0	31	
Three-phase Reactive Power Max Date Month	03, 04	KVR3XD_M	1	0	12	
Three-phase Reactive Power Max Date Year	03, 04	KVR3XD_Y	1	0	9999	
Three-phase Apparent Power Min	03, 04	KVA3MIN[f]	2	–2147483648	2147483647	
Three-phase Apparent Power Min Time Seconds	03, 04	KVA3NT_S	1	0	59999	1000
Three-phase Apparent Power Min Time Minutes	03, 04	KVA3NT_M	1	0	59	
Three-phase Apparent Power Min Time Hour	03, 04	KVA3NT_H	1	0	23	
Three-phase Apparent Power Min Date Day	03, 04	KVA3ND_D	1	0	31	
Three-phase Apparent Power Min Date Month	03, 04	KVA3ND_M	1	0	12	
Three-phase Apparent Power Min Date Year	03, 04	KVA3ND_Y	1	0	9999	
Three-phase Real Power Min	03, 04	KW3MIN[f]	2	–2147483648	2147483647	
Three-phase Real Power Min Time Seconds	03, 04	KW3MNT_S	1	0	59999	1000
Three-phase Real Power Min Time Minutes	03, 04	KW3MNT_M	1	0	59	
Three-phase Real Power Min Time Hour	03, 04	KW3MNT_H	1	0	23	
Three-phase Real Power Min Date Day	03, 04	KW3MND_D	1	0	31	
Three-phase Real Power Min Date Month	03, 04	KW3MND_M	1	0	12	
Three-phase Real Power Min Date Year	03, 04	KW3MND_Y	1	0	9999	
Three-phase Reactive Power Min	03, 04	KVR3MIN[f]	2	–2147483648	2147483647	
Three-phase Reactive Power Min Time Seconds	03, 04	KVR3NT_S	1	0	59999	1000
Three-phase Reactive Power Min Time Minutes	03, 04	KVR3NT_M	1	0	59	
Three-phase Reactive Power Min Time Hour	03, 04	KVR3NT_H	1	0	23	
Three-phase Reactive Power Min Date Day	03, 04	KVR3ND_D	1	0	31	
Three-phase Reactive Power Min Date Month	03, 04	KVR3ND_M	1	0	12	
Three-phase Reactive Power Min Date Year	03, 04	KVR3ND_Y	1	0	9999	
Harmonic and RMS Metering Data						
Phase A Current THD	03, 04	IAHT	1	0	995	
Phase B Current THD	03, 04	IBHT	1	0	995	
Phase C Current THD	03, 04	ICHT	1	0	995	
Neutral Current THD	03, 04	INHT	1	0	995	
Phase A Y-Terminal Voltage THD	03, 04	VAYHT	1	0	995	
Phase B Y-Terminal Voltage THD	03, 04	VBYHT	1	0	995	
Phase C Y-Terminal Voltage THD	03, 04	VCYHT	1	0	995	
Phase A Z-Terminal Voltage THD	03, 04	VAZHT	1	0	995	
Phase B Z-Terminal Voltage THD	03, 04	VBZHT	1	0	995	
Phase C Z-Terminal Voltage THD	03, 04	VCZHT	1	0	995	
Phase A RMS Current	03, 04	IAR	1	0	65535	

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Table K.22 Modbus Quantities Table (Sheet 12 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase B RMS Current	03, 04	IBR	1	0	65535	
Phase C RMS Current	03, 04	ICR	1	0	65535	
Neutral RMS Current	03, 04	INR	1	0	65535	
Phase A Y-Terminal RMS Voltage	03, 04	VAYR	2	0	4294967295	
Phase B Y-Terminal RMS Voltage	03, 04	VBYR	2	0	4294967295	
Phase C Y-Terminal RMS Voltage	03, 04	VCYR	2	0	4294967295	
Phase A Z-Terminal RMS Voltage	03, 04	VAZR	2	0	4294967295	
Phase B Z-Terminal RMS Voltage	03, 04	VBZR	2	0	4294967295	
Phase C Z-Terminal RMS Voltage	03, 04	VCZR	2	0	4294967295	
Phase A Fundamental Current (from harmonics calculation)	03, 04	IAH01	1	0	65535	
Phase A Current Harmonic Content	03, 04	IAHnn[g]	1	0	995	
Phase B Fundamental Current (from harmonics calculation)	03, 04	IBH01	1	0	65535	
Phase B Current Harmonic Content	03, 04	IBHnn[g]	1	0	995	
Phase C Fundamental Current (from harmonics calculation)	03, 04	ICH01	1	0	65535	
Phase C Current Harmonic Content	03, 04	ICHnn[g]	1	0	995	
Neutral Fundamental Current (from harmonics calculation)	03, 04	INH01	1	0	65535	
Neutral Current Harmonic Content	03, 04	INHnn[g]	1	0	995	
VAY Fundamental Voltage (from harmonics calculation)	03, 04	VAYH01	2	0	4294967295	
VAY Harmonic Content	03, 04	VAYHnn[g]	1	0	995	
VBY Fundamental Voltage (from harmonics calculation)	03, 04	VBYH01	2	0	4294967295	
VBY Harmonic Content	03, 04	VBYHnn[g]	1	0	995	
VCY Fundamental Voltage (from harmonics calculation)	03, 04	VCYH01	2	0	4294967295	
VCY Harmonic Content	03, 04	VCYHnn[g]	1	0	995	
VAZ Fundamental Voltage (from harmonics calculation)	03, 04	VAZH01	2	0	4294967295	
VAZ Harmonic Content	03, 04	VAZHnn[g]	1	0	995	
VBZ Fundamental Voltage (from harmonics calculation)	03, 04	VBZH01	2	0	4294967295	
VBZ Harmonic Content	03, 04	VBZHnn[g]	1	0	995	
VCZ Fundamental Voltage (from harmonics calculation)	03, 04	VCZH01	2	0	4294967295	
VCZ Harmonic Content	03, 04	VCZHnn[g]	1	0	995	
Phase A RMS Power	03, 04	KWAR	2	–2147483648	2147483647	
Phase B RMS Power	03, 04	KWBR	2	–2147483648	2147483647	
Phase C RMS Power	03, 04	KWCR	2	–2147483648	2147483647	
Three-phase RMS Power	03, 04	KW3R	2	–2147483648	2147483647	

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Table K.22   Modbus Quantities Table (Sheet 13 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Diagnostics and Relay Information						
+5 Volt Power Supply	03, 04	P5V_PS	1	0	65535	100
+5 Volt Regulated Power Supply	03, 04	P5V_REG	1	0	65535	100
+15 Volt Power Supply	03, 04	P15V_PS	1	0	65535	100
–15 Volt Power Supply	03, 04	N15V_PS	1	–32768	0	100
+12 Volt Trip Capacitor Control Supply	03, 04	P12V_TC	1	0	65535	100
+5V Analog Power Supply	03, 04	P5VA_PS	1	0	65535	100
–5V Analog Power Supply	03, 04	N5VA_PS	1	–32768	0	100
Relay Serial Number Lowest 4 Digits	03, 04	SNUMBL	1	0	9999	
Relay Serial Number Middle 4 Digits	03, 04	SNUMBM	1	0	9999	
Relay Serial Number Highest 4 Digits	03, 04	SNUMBH	1	0	9999	
Relay Firmware Revision	03, 04	FWREV	1	0	9999	
Relay Firmware Version Number	03, 04	FWVNUM	1	0	9999	
Battery Voltage	03, 04	VBAT	1	–5000	5000	10
Battery Current	03, 04	IBAT	1	–32768	32767	100
Battery Temperature	03, 04	TBAT	1	–400	1250	10
Battery Charger Mode	03, 04	CMODE[h]	1	0	9	
Input Power Bus Voltage	03, 04	INPBV	1	0	65535	100
12 V Aux Supply Voltage	03, 04	12VAUX	1	0	65535	100
Trip/Close Cap. Voltage	03, 04	TCCAPV	1	0	65535	10
Temperature	03, 04	TEMP	1	–400	1250	10
Breaker Monitor						
Internal A-Phase Trip Counter	03, 04	INTTA	1	0	65535	
Internal B-Phase Trip Counter	03, 04	INTTB	1	0	65535	
Internal C-Phase Trip Counter	03, 04	INTTC	1	0	65535	
External A-Phase Trip Counter	03, 04	EXTTA	1	0	65535	
External B-Phase Trip Counter	03, 04	EXTTB	1	0	65535	
External C-Phase Trip Counter	03, 04	EXTTC	1	0	65535	
Phase A Operations Counter	03, 04	OPSCTRA	2	0	131070	
Phase B Operations Counter	03, 04	OPSCTRB	2	0	131070	
Phase C Operations Counter	03, 04	OPSCTRC	2	0	131070	
Phase A Accumulated Current Internal Trips	03, 04	INTIA	2	0	999999	
Phase B Accumulated Current Internal Trips	03, 04	INTIB	2	0	999999	
Phase C Accumulated Current Internal Trips	03, 04	INTIC	2	0	999999	
Phase A Accumulated Current External Trips	03, 04	EXTIA	2	0	999999	
Phase B Accumulated Current External Trips	03, 04	EXTIB	2	0	999999	
Phase C Accumulated Current External Trips	03, 04	EXTIC	2	0	999999	
Phase A Involved Trips Count	03, 04	APHTR	1	0	65535	

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Table K.22 Modbus Quantities Table (Sheet 14 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
Phase B Involved Trips Count	03, 04	BPHTR	1	0	65535	
Phase C Involved Trips Count	03, 04	CPHTR	1	0	65535	
Ground Involved Trips Count	03, 04	GNDCTR	1	0	65535	
Breaker Wear A-Phase	03, 04	WEARA	1	0	65535	
Breaker Wear B-Phase	03, 04	WEARB	1	0	65535	
Breaker Wear C-Phase	03, 04	WEARC	1	0	65535	
Max Breaker Wear	03, 04	MAXWEAR	1	0	65535	
Breaker Type	03, 04	BKTYP	1	1	3	
Math Variables						
Math Variables 1–64	03, 04	MV01–MV64	2	–1600000	1600000	
SELOGIC Counters						
SELOGIC Counters 1–16	03, 04	SC01–SC16	1	0	65535	
Modbus Communication Counters						
Num Messages Received	03, 04	**MSGRCD**	1	0	65535	
Num Msgs to Other devices (Other ID)	03, 04	**MSGOID**	1	0	65535	
Illegal Address	03, 04	**ILLADDR**	1	0	65535	
Bad CRC	03, 04	**BADCRC**	1	0	65535	
Uart Error	03, 04	**UARTER**	1	0	65535	
Illegal Function	03, 04	**ILLFUNC**	1	0	65535	
Illegal Register	03, 04	**ILLREG**	1	0	65535	
Illegal Data	03, 04	**ILLDATA**	1	0	65535	
Bad Packet Format	03, 04	**BADPF**	1	0	65535	
Bad Packet Length	03, 04	**BADPL**	1	0	65535	
Active Group						
Active Settings Group	03, 04, 06, 10h	ACTGRP[i]	1	1	8	
Relay Elements (See Appendix F: Relay Word Bits for relay element row numbers and definitions)						
ROW 0	03, 04	ROW_0	1	0	255	
ROW 1	03, 04	ROW_1	1	0	255	
ROW 2	03, 04	ROW_2	1	0	255	
ROW 3	03, 04	ROW_3	1	0	255	
ROW 4	03, 04	ROW_4	1	0	255	
ROW 5	03, 04	ROW_5	1	0	255	
ROW 6	03, 04	ROW_6	1	0	255	
ROW 7	03, 04	ROW_7	1	0	255	
ROW 8	03, 04	ROW_8	1	0	255	
ROW 9	03, 04	ROW_9	1	0	255	
ROW 10	03, 04	ROW_10	1	0	255	
ROW 11	03, 04	ROW_11	1	0	255	
ROW 12	03, 04	ROW_12	1	0	255	

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Table K.22 Modbus Quantities Table (Sheet 15 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
ROW 13	03, 04	ROW_13	1	0	255	
ROW 14	03, 04	ROW_14	1	0	255	
ROW 15	03, 04	ROW_15	1	0	255	
ROW 16	03, 04	ROW_16	1	0	255	
ROW 17	03, 04	ROW_17	1	0	255	
ROW 18	03, 04	ROW_18	1	0	255	
ROW 19	03, 04	ROW_19	1	0	255	
ROW 20	03, 04	ROW_20	1	0	255	
ROW 21	03, 04	ROW_21	1	0	255	
ROW 22	03, 04	ROW_22	1	0	255	
ROW 23	03, 04	ROW_23	1	0	255	
ROW 24	03, 04	ROW_24	1	0	255	
ROW 25	03, 04	ROW_25	1	0	255	
ROW 26	03, 04	ROW_26	1	0	255	
ROW 27	03, 04	ROW_27	1	0	255	
ROW 28	03, 04	ROW_28	1	0	255	
ROW 29	03, 04	ROW_29	1	0	255	
ROW 30	03, 04	ROW_30	1	0	255	
ROW 31	03, 04	ROW_31	1	0	255	
ROW 32	03, 04	ROW_32	1	0	255	
ROW 33	03, 04	ROW_33	1	0	255	
ROW 34	03, 04	ROW_34	1	0	255	
ROW 35	03, 04	ROW_35	1	0	255	
ROW 36	03, 04	ROW_36	1	0	255	
ROW 37	03, 04	ROW_37	1	0	255	
ROW 38	03, 04	ROW_38	1	0	255	
ROW 39	03, 04	ROW_39	1	0	255	
ROW 40	03, 04	ROW_40	1	0	255	
ROW 41	03, 04	ROW_41	1	0	255	
ROW 42	03, 04	ROW_42	1	0	255	
ROW 43	03, 04	ROW_43	1	0	255	
ROW 44	03, 04	ROW_44	1	0	255	
ROW 45	03, 04	ROW_45	1	0	255	
ROW 46	03, 04	ROW_46	1	0	255	
ROW 47	03, 04	ROW_47	1	0	255	
ROW 48	03, 04	ROW_48	1	0	255	
ROW 49	03, 04	ROW_49	1	0	255	
ROW 50	03, 04	ROW_50	1	0	255	
ROW 51	03, 04	ROW_51	1	0	255	
ROW 52	03, 04	ROW_52	1	0	255	

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Table K.22   Modbus Quantities Table (Sheet 16 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
ROW 53	03, 04	ROW_53	1	0	255	
ROW 54	03, 04	ROW_54	1	0	255	
ROW 55	03, 04	ROW_55	1	0	255	
ROW 56	03, 04	ROW_56	1	0	255	
ROW 57	03, 04	ROW_57	1	0	255	
ROW 58	03, 04	ROW_58	1	0	255	
ROW 59	03, 04	ROW_59	1	0	255	
ROW 60	03, 04	ROW_60	1	0	255	
ROW 61	03, 04	ROW_61	1	0	255	
ROW 62	03, 04	ROW_62	1	0	255	
ROW 63	03, 04	ROW_63	1	0	255	
ROW 64	03, 04	ROW_64	1	0	255	
ROW 65	03, 04	ROW_65	1	0	255	
ROW 66	03, 04	ROW_66	1	0	255	
ROW 67	03, 04	ROW_67	1	0	255	
ROW 68	03, 04	ROW_68	1	0	255	
ROW 69	03, 04	ROW_69	1	0	255	
ROW 70	03, 04	ROW_70	1	0	255	
ROW 71	03, 04	ROW_71	1	0	255	
ROW 72	03, 04	ROW_72	1	0	255	
ROW 73	03, 04	ROW_73	1	0	255	
ROW 74	03, 04	ROW_74	1	0	255	
ROW 75	03, 04	ROW_75	1	0	255	
ROW 76	03, 04	ROW_76	1	0	255	
ROW 77	03, 04	ROW_77	1	0	255	
ROW 78	03, 04	ROW_78	1	0	255	
ROW 79	03, 04	ROW_79	1	0	255	
ROW 80	03, 04	ROW_80	1	0	255	
ROW 81	03, 04	ROW_81	1	0	255	
ROW 82	03, 04	ROW_82	1	0	255	
ROW 83	03, 04	ROW_83	1	0	255	
ROW 84	03, 04	ROW_84	1	0	255	
ROW 85	03, 04	ROW_85	1	0	255	
ROW 86	03, 04	ROW_86	1	0	255	
ROW 87	03, 04	ROW_87	1	0	255	
ROW 88	03, 04	ROW_88	1	0	255	
ROW 89	03, 04	ROW_89	1	0	255	
ROW 90	03, 04	ROW_90	1	0	255	
ROW 91	03, 04	ROW_91	1	0	255	
ROW 92	03, 04	ROW_92	1	0	255	

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Table K.22   Modbus Quantities Table (Sheet 17 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
ROW 93	03, 04	ROW_93	1	0	255	
ROW 94	03, 04	ROW_94	1	0	255	
ROW 95	03, 04	ROW_95	1	0	255	
ROW 96	03, 04	ROW_96	1	0	255	
ROW 97	03, 04	ROW_97	1	0	255	
ROW 98	03, 04	ROW_98	1	0	255	
ROW 99	03, 04	ROW_99	1	0	255	
ROW 100	03, 04	ROW_100	1	0	255	
ROW 101	03, 04	ROW_101	1	0	255	
ROW 102	03, 04	ROW_102	1	0	255	
ROW 103	03, 04	ROW_103	1	0	255	
ROW 104	03, 04	ROW_104	1	0	255	
ROW 105	03, 04	ROW_105	1	0	255	
ROW 106	03, 04	ROW_106	1	0	255	
ROW 107	03, 04	ROW_107	1	0	255	
ROW 108	03, 04	ROW_108	1	0	255	
ROW 109	03, 04	ROW_109	1	0	255	
ROW 110	03, 04	ROW_110	1	0	255	
ROW 111	03, 04	ROW_111	1	0	255	
ROW 112	03, 04	ROW_112	1	0	255	
ROW 113	03, 04	ROW_113	1	0	255	
ROW 114	03, 04	ROW_114	1	0	255	
ROW 115	03, 04	ROW_115	1	0	255	
ROW 116	03, 04	ROW_116	1	0	255	
ROW 117	03, 04	ROW_117	1	0	255	
ROW 118	03, 04	ROW_118	1	0	255	
ROW 119	03, 04	ROW_119	1	0	255	
ROW 120	03, 04	ROW_120	1	0	255	
ROW 121	03, 04	ROW_121	1	0	255	
ROW 122	03, 04	ROW_122	1	0	255	
ROW 123	03, 04	ROW_123	1	0	255	
ROW 124	03, 04	ROW_124	1	0	255	
ROW 125	03, 04	ROW_125	1	0	255	
ROW 126	03, 04	ROW_126	1	0	255	
ROW 127	03, 04	ROW_127	1	0	255	
ROW 128	03, 04	ROW_128	1	0	255	
ROW 129	03, 04	ROW_129	1	0	255	
ROW 130	03, 04	ROW_130	1	0	255	
ROW 131	03, 04	ROW_131	1	0	255	
ROW 132	03, 04	ROW_132	1	0	255	

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Table K.22   Modbus Quantities Table (Sheet 18 of 18)

Description	Valid Function Codes	SET_M Point Label/ Enums[a]	Number of 16-Bit Registers[b]	Min Value	Max Value	Scaling (X1 unless specified)
ROW 133	03, 04	ROW_133	1	0	255	
ROW 134	03, 04	ROW_134	1	0	255	
ROW 135	03, 04	ROW_135	1	0	255	

[a] Point names appearing in bold may only be assigned to a single register in the User Map. If an attempt is made to assign one of these points to multiple registers, the relay will respond with the error message, `Value may only appear in the map once`.

[b] For quantities using two 16-bit registers, the register with the lower index is the most significant word and the register with the higher index is the least significant word in the 32-bit quantity.

[c] If the fault location is undefined, Modbus will report the value as 32767.

[d] FTARLO represents the status of the Target LEDs T01LED–T16LED. The lower 8 bits of FTARHI represent the status of Target LEDs T17LED–T24LED. The upper 8 bits of FTARHI are unused.

[e] Breaker Close and Breaker Open are mutually exclusive and the relay asserts neither bit and returns the Exception Response if an attempt is made to write both bits.

[f] Minimum values that have been reset report the largest positive value possible. Maximum values that have been reset report the largest negative value possible.

[g] Where nn represents the 2nd through the 16th harmonics.

[h] See Battery Status on page 8.43 for Battery Charger Mode definitions.

[i] The active settings group can be modified by writing the desired settings group number to ACTGRP. If a logic setting has been programmed to control the active settings group, the write will be accepted but the active group will not change.

Table K.23   Default Modbus Map (Sheet 1 of 2)

Modbus Address	User Map Register	Mapped Register Label[a]	Notes
000	MOD_001	IA	
001	MOD_002	IAFA	
002	MOD_003	IB	
003	MOD_004	IBFA	
004	MOD_005	IC	
005	MOD_006	ICFA	
006	MOD_007	IG	
007	MOD_008	IGFA	
008	MOD_009	IN	
009	MOD_010	INFA	
010	MOD_011	**VAY**	
012	MOD_013	VAYFA	
013	MOD_014	**VBY**	
015	MOD_016	VBYFA	
016	MOD_017	**VCY**	
018	MOD_019	VCYFA	
019	MOD_020	**VAZ**	
021	MOD_022	VAZFA	
022	MOD_023	**VBZ**	
024	MOD_025	VBZFA	
025	MOD_026	**VCZ**	
027	MOD_028	VCZFA	
028	MOD_029	**KW3**	
030	ATOD_031	**KVAR3**	
032	MOD_033	PF3	

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Table K.23   Default Modbus Map (Sheet 2 of 2)

Modbus Address	User Map Register	Mapped Register Label[a]	Notes
033	MOD_034	LDPF3	
034	MOD_035	FREQ	
035	MOD_036	VBAT	
036	MOD_037	**MWH3I**	
038	MOD_039	**MWH3O**	
040	MOD_041	**MVRH3I**	
042	MOD_043	**MVRH3O**	
044	MOD_045	ACTGRP	
045	MOD_046	ROW_1	Front-panel indicator LEDs
046	MOD_047	ROW_2	Front-panel indicator LEDs
047	MOD_048	ROW_3	Front-panel indicator LEDs
048	MOD_049	ROW_64	Contains 79RS3P, 79CY3P, 79LO3P
049	MOD_050	ROW_18	Contains 52AA, 52AB, 52AC
050–249	MOD_051–MOD_250	Not Assigned	
250–1000		Reserved	
1001–1016		RID	Value of setting RID, two characters per register[b]
1017–1032		TID	Value of setting TID, two characters per register[a]
1033–65535		Reserved	

[a] Register labels appearing in bold are 32-bit quantities and consume two registers.

[b] Modbus Addresses 1001–1032 contain string data. Strings are packed 2 characters per register, with the most significant bit containing the character closest to the beginning of the string.

Reading Event Data Via Modbus

The SEL-651R-2 provides a feature that allows relay event history data to be retrieved via Modbus. The Event History registers are listed in *Table K.22* under the Historical Data description heading. To read the history data, set the Modbus Map to contain the EVESEL label, along with the other Fault History related labels. The following example shows some of the available history data labels in the Modbus Map:

```
=>> SHO M <Enter>

MOD_001 = NUMEVE
MOD_002 = EVESEL
MOD_003 = FTIME_S
MOD_004 = FTIME_M
MOD_005 = FTIME_H
MOD_006 = FDATE_D
MOD_007 = FDATE_M
MOD_008 = FDATE_Y
MOD_009 = FLOC
MOD_010 = FI
MOD_011 = FIA
MOD_012 = FIB
MOD_013 = FIC
MOD_014 = FIG
MOD_015 = FIQ
MOD_016 = FFREQ
MOD_017 = FGRP
MOD_018 = FSHO
MOD_019 = EVE_TYPE
```

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Use Modbus function code 03 or 04 to read the Modbus registers. The NUMEVE label will contain the number of events listed in the event history, **HIS** command, and response. To read event history data via Modbus, use function code 06 to write the event number to the Modbus register containing the EVESEL label. The SEL-651R-2 will populate the other event related registers with the data relayed to the event number specified in the EVESEL label address. Issue a Modbus function code 03 or 04 command to read the registers containing the history data.

For example, consider the following **HIS** command:

```
=>> HIS <Enter>

SEL-651R-2                          Date: 10/30/2015  Time: 23:17:03.346
FEEDER 1                            Time Source: internal

#    DATE       TIME       EVENT LOCAT  CURR FREQ GST          TARGETS
                                                  RHR    COLUMN 1      COLUMN 2
1  10/25/2015 12:52:44.876 CA     2.26 3024 60.0 131 111000001000 001000000000
2  10/25/2015 11:12:16.812 AB T   0.10 4168 60.0 131 111100001000 001100000000
3  10/25/2015 11:05:26.805 AB T   0.10 4078 60.0 131 111100001000 001100000000
```

To retrieve the history data for Event number 2 in this example, set register address 0001 to the value of 2 by using a function code 06 command. (Note that the Modbus Map is indexed beginning with 1, which corresponds to register address 0 in Modbus.) If a value is written to the EVESEL register for an event that does not currently exist in the history data, the SEL-651R-2 will respond with an exception code 03.

Following the function code 06 command, issue a function code 03 or 04 command to read registers that follow (e.g., MOD_003 = FTIME_S through MOD_019 = EVE_TYPE in the preceding example map). The data returned contain the event time, event date, fault location, maximum fault current, fault current per phase, ground fault current, negative-sequence fault current, frequency, settings group, number of shots, and event type associated with Event number 2.

The relay can report the EVE_TYPE value as a composite of the numbers listed in Event Type under *Historical Data* in *Table K.22*. For example, a CAG T event type shall have an EVE_TYPE analog value of 77 (CAG + Trip). Likewise, a CAG event triggered by a Relay Word bit in the ER equation shall have an EVE_TYPE analog value of 141 (CAG + ER).

The **HIS E** command returns the same history data, but uses a unique event number in the range of 10000–65535. The SEL-651R-2 will also return the history data if the unique event number (e.g., 10008) is written to the EVESEL register as long as that event is currently in the history data.

```
=>> HIS E <Enter>

SEL-651R-2                           Date: 10/30/2015  Time: 23:17:03.346
FEEDER 1                             Time Source: internal

#        DATE       TIME       EVENT LOCAT  CURR FREQ GST          TARGETS
                                                      RHR    COLUMN 1      COLUMN 2
10007  10/25/2015 12:52:44.876 CA     2.26 3024 60.0 131 111000001000 001000000000
10008  10/25/2015 11:12:16.812 AB T   0.10 4168 60.0 131 111100001000 001100000000
10009  10/25/2015 11:05:26.805 AB T   0.10 4078 60.0 131 111100001000 001100000000
```

If the history data are cleared (either from the **HIS C** command or a remote control point), the value in the NUMEVE register is changed to 0. This indicates that there are no events listed in the event history. The Modbus fault data registers may still contain data from a past event until a new valid event number is written to the EVESEL register.

Date _____

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Modbus Settings Sheets

Modbus Map Settings (SET M Command)

Modbus User Map

See Table K.22 for list of valid labels.

NOTE: 32-bit values, such as VA, VB, and VC, consume two registers. When assigning registers, skip the registers following a 32-bit value to avoid errors in settings.

User Map Register Label Name	**MOD_001**	= _____
User Map Register Label Name	**MOD_002**	= _____
User Map Register Label Name	**MOD_003**	= _____
User Map Register Label Name	**MOD_004**	= _____
User Map Register Label Name	**MOD_005**	= _____
User Map Register Label Name	**MOD_006**	= _____
User Map Register Label Name	**MOD_007**	= _____
User Map Register Label Name	**MOD_008**	= _____
User Map Register Label Name	**MOD_009**	= _____
User Map Register Label Name	**MOD_010**	= _____
User Map Register Label Name	**MOD_011**	= _____
User Map Register Label Name	**MOD_012**	= _____
User Map Register Label Name	**MOD_013**	= _____
User Map Register Label Name	**MOD_014**	= _____
User Map Register Label Name	**MOD_015**	= _____
User Map Register Label Name	**MOD_016**	= _____
User Map Register Label Name	**MOD_017**	= _____
User Map Register Label Name	**MOD_018**	= _____
User Map Register Label Name	**MOD_019**	= _____
User Map Register Label Name	**MOD_020**	= _____
User Map Register Label Name	**MOD_021**	= _____
User Map Register Label Name	**MOD_022**	= _____
User Map Register Label Name	**MOD_023**	= _____
User Map Register Label Name	**MOD_024**	= _____
User Map Register Label Name	**MOD_025**	= _____
User Map Register Label Name	**MOD_026**	= _____
User Map Register Label Name	**MOD_027**	= _____
User Map Register Label Name	**MOD_028**	= _____

User Map Register Label Name   **MOD_029** = _____

User Map Register Label Name   **MOD_030** = _____

User Map Register Label Name   **MOD_031** = _____

User Map Register Label Name   **MOD_032** = _____

User Map Register Label Name   **MOD_033** = _____

User Map Register Label Name   **MOD_034** = _____

User Map Register Label Name   **MOD_035** = _____

User Map Register Label Name   **MOD_036** = _____

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User Map Register Label Name   **MOD_064** = _____

User Map Register Label Name   **MOD_065** = _____

Date _____

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User Map Register Label Name   **MOD_066** = _____

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User Map Register Label Name   **MOD_125** = _____

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User Map Register Label Name   **MOD_127** = _____

User Map Register Label Name   **MOD_128** = _____

User Map Register Label Name   **MOD_129** = _____

User Map Register Label Name   **MOD_130** = _____

User Map Register Label Name   **MOD_131** = _____

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User Map Register Label Name   **MOD_135** = _____

User Map Register Label Name   **MOD_136** = _____

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User Map Register Label Name   **MOD_139** = _____

Date _____

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Page 970 of 1080
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Wolfe

User Map Register Label Name	**MOD_140** = _____
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User Map Register Label Name	**MOD_211**	=	_____
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User Map Register SET Label Name	**MOD_213**	=	_____

Date _____

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User Map Register Label Name	**MOD_214**	=	
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User Map Register Label Name	**MOD_249**	=	
User Map Register Label Name	**MOD_250**	=	

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Appendix L

IEC 61850

Features

The SEL-651R-2 supports the following features using Ethernet and IEC 61850:

➤ **SCADA**—Connect as many as seven simultaneous IEC 61850 MMS client sessions. The SEL-651R-2 also supports as many as seven buffered and seven unbuffered report control blocks. See the CON Logical Device Table for Logical Node mapping that enables SCADA control via a Manufacturing Messaging Specification (MMS) browser. Controls support the direct control, select before operate control (SBO), and SBO with enhanced security control models.

➤ **Peer-to-Peer Real-Time Status and Control**—Use GOOSE with as many as 24 incoming (receive) and 8 outgoing (transmit) messages. Virtual bits (VB001–VB128) can be mapped from incoming GOOSE messages.

➤ **Configuration**—Use FTP client software or ACSELERATOR Architect SEL-5032 Software to transfer the Substation Configuration Language (SCL) Configured IED Description (CID) file to the relay.

➤ **Commissioning and Troubleshooting**—Use software such as MMS Object Explorer and AX-S4 MMS from Sisco, Inc., to browse the relay logical nodes and verify functionality.

This section presents the information you need to use the IEC 61850 features of the SEL-651R-2:

➤ *Introduction to IEC 61850 on page L.1*

➤ *IEC 61850 Operation on page L.3*

➤ *IEC 61850 Configuration on page L.21*

➤ *Logical Nodes on page L.26*

➤ *ACSI Conformance Statements on page L.58*

Introduction to IEC 61850

In the early 1990s, the Electric Power Research Institute (EPRI) and the Institute of Electrical and Electronics Engineers, Inc. (IEEE) began to define a Utility Communications Architecture (UCA). They initially focused on inter-control center and substation-to-control center communications and produced

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the Inter-Control Center Communications Protocol (ICCP) specification. This specification, later adopted by the IEC as 60870-6 TASE.2, became the standard protocol for real-time exchange of data between databases.

In 1994, EPRI and IEEE began work on UCA 2.0 for Field Devices (simply referred to as UCA2). In 1997, they combined efforts with Technical Committee 57 of the IEC to create a common international standard. Their joint efforts created the current IEC 61850 standard.

The IEC 61850 standard, a superset of UCA2, contains most of the UCA2 specification, plus additional functionality. The standard describes client/ server and peer-to-peer communications, substation design and configuration, testing, and project standards.

The IEC 61850 standard consists of the parts listed in *Table L.1*.

Table L.1   IEC 61850 Document Set

IEC 61850 Sections	Definitions
IEC 61850-1	Introduction and overview
IEC 61850-2	Glossary
IEC 61850-3	General requirements
IEC 61850-4	System and project management
IEC 61850-5	Communication requirements
IEC 61850-6	Configuration description language for substation IEDs
IEC 61850-7-1	Basic communication structure for substations and feeder equipment—Principles and models
IEC 61850-7-2	Basic communication structure for substations and feeder equipment—Abstract communication service interface (ACSI)
IEC 61850-7-3	Basic communication structure for substations and feeder equipment—Common data classes
IEC 61850-7-4	Basic communication structure for substations and feeder equipment— Compatible logical node (LN) classes and data classes
IEC 61850-8-1	SCSM—Mapping to Manufacturing Messaging Specification (MMS) (ISO/IEC 9506-1 and ISO/IEC 9506-2 over ISO/IEC 8802-3)
IEC 61850-9-1	SCSM—Sampled values over serial multidrop point-to-point link
IEC 61850-9-2	SCSM—Sampled values over ISO/IEC 8802-3
IEC 61850-10	Conformance testing

The IEC 61850 document set, available directly from the IEC at www.iec.ch, contains information necessary for successful implementation of this protocol. SEL strongly recommends that anyone involved with the design, installation, configuration, or maintenance of IEC 61850 systems be familiar with the appropriate sections of this standard.

IEC 61850 Operation

Ethernet Networking

IEC 61850 and Ethernet networking model options are available when ordering a new SEL-651R-2 and may also be available as field upgrades to relays equipped with dual copper and dual or single fiber-optic Ethernet. In addition to IEC 61850, the relay provides support protocols and data exchange, including FTP and Telnet. Access the SEL-651R-2 Port 5 settings to configure all of the Ethernet settings, including IEC 61850 enable settings.

The SEL-651R-2 supports IEC 61850 services, including transport of Logical Node objects, over TCP/IP. The relay can coordinate a maximum of seven concurrent IEC 61850 sessions.

Object Models

The IEC 61850 standard relies heavily on the Abstract Communication Service Interface (ACSI) models to define a set of services and the responses to those services. In terms of network behavior, abstract modeling enables all IEDs to act identically. These abstract models are used to create objects (data items) and services that exist independently of any underlying protocols. These objects are in conformance with the common data class (CDC) specification IEC 61850-7-3, which describes the type and structure of each element within a logical node. CDCs for status, measurements, controllable analogs and statuses, and settings all have unique CDC attributes. Each CDC attribute belongs to a set of functional constraints that groups the attributes into specific categories such as status (ST), description (DC), and substituted value (SV). Functional constraints, CDCs, and CDC attributes are used as building blocks for defining Logical Nodes.

UCA2 used GOMSFE (Generic Object Models for Substation and Feeder Equipment) to present data from station IEDs as a series of objects called models or bricks. The IEC working group has incorporated GOMSFE concepts into the standard, with some modifications to terminology; one change was the renaming of bricks to logical nodes. Each logical node represents a group of data (controls, status, measurements, etc.) associated with a particular function. For example, the MMXU logical node (polyphase measurement unit) contains measurement data and other points associated with three-phase metering including voltages and currents. Each IED may contain many functions such as protection, metering, and control. Multiple logical nodes represent the functions in multifunction devices.

Logical nodes can be organized into logical devices that are similar to directories on a computer disk. As represented in the IEC 61850 network, each physical device can contain many logical devices and each logical device can contain many logical nodes. Many relays, meters, and other IEC 61850 devices contain one primary logical device where all models are organized.

IEC 61850 devices are capable of self-description. You do not need to refer to the specifications for the logical nodes, measurements, and other components to request data from another IEC 61850 device. IEC 61850 clients can request and display a list and description of the data available in an IEC 61850 server device. This process is similar to the autoconfiguration process used within SEL communications processors (SEL-2032 and SEL-2030). Simply run an MMS browser to query devices on an IEC 61850 network and discover what data are available. Self-description also permits extensions to both standard and custom data models. Instead of having to look up data in a profile stored in its database, an IEC 61850 client can simply query an IEC 61850 device and receive a description of all logical devices, logical nodes, and available data.

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IEC 61850 Operation

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Unlike other Supervisory Control and Data Acquisition (SCADA) protocols that present data as a list of addresses or indices, IEC 61850 presents data with descriptors in a composite notation made up of components. *Table L.2* shows how the A-phase current expressed as METMMXU1AphsA$cVal is broken down into its component parts. The Data Attribute is characterized (filtered) by a functional constraint (FC) property. The supported FCs are listed in *Table L.3*. The FC for the given example above is MX.

Table L.2   Example IEC 61850 Descriptor Components

Component		Description
METMMXU1	Logical Node	Polyphase measurement unit
A	Data Object	Phase-to-ground amperes
phsA	Sub-Data Object	Phase A
cVal	Data Attribute	Complex value

Table L.3   Functional Constraints

FC	Description
ST	Status information
MX	Measurements (analog values)
CO	Control
CF	Configuration
DC	Description
EX	Extended definition

Data Mapping

Device data are mapped to IEC 61850 Logical Nodes (LN) according to rules defined by SEL. Refer to IEC 61850-5:2003(E) and IEC 61850-7-4:2003(E) for the mandatory content and usage of these LNs. The SEL-651R-2 logical nodes are grouped under Logical Devices for organization based on function. See *Table L.4* for descriptions of the Logical Devices in an SEL-651R-2. See *Logical Nodes on page L.26* for a description of the LNs that make up these Logical Devices.

Table L.4   SEL-651R-2 Logical Devices

Logical Device	Description
ANN	Annunciator elements—alarms, status values
CFG	Configuration elements—datasets and report control blocks
CON	Control elements—remote bits
MET	Metering or Measurement elements—currents, voltages, power, etc.
PRO	Protection elements—protection functions and breaker control

MMS

Manufacturing Messaging Specification (MMS) provides services for the application-layer transfer of real-time data within a substation LAN. MMS was developed as a network independent data exchange protocol for industrial networks in the 1980s and standardized as ISO 9506.

In theory, you can map IEC 61850 to any protocol. However, it can become unwieldy and quite complicated to map objects and services to a protocol that only provides access to simple data points via registers or index numbers. MMS supports complex named objects and flexible services that enable

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mapping to IEC 61850 in a straightforward manner. This was why the UCA users group used MMS for UCA from the start, and why the IEC chose to keep it for IEC 61850.

Event files are also available through MMS. See *File Transfer Protocol (FTP) and MMS File Transfer on page 10.17* and *Retrieving COMTRADE Event Files on page 12.15*. If MMS authentication is enabled, the device will authenticate each MMS association by requiring the client to provide the password authentication parameter with a value that is equal to the 2AC password of the SEL-651R-2.

> ➤ If the correct password authentication parameter value is not received, the device will return a `not authenticated` error code.

> ➤ If the correct password authentication parameter value is received, the device will give a successful association response. The device will allow access to all supported MMS services for that association.

GOOSE

The Generic Object Oriented Substation Event (GOOSE) object within IEC 61850 is for high-speed control messaging. IEC 61850 GOOSE automatically broadcasts messages containing status, controls, and measured values onto the network for use by other devices. IEC 61850 GOOSE sends the message several times, increasing the likelihood that other devices receive the messages. GOOSE message publication is a persistent function. Once GOOSE is enabled, the IED will continuously publish GOOSE messages until they are disabled regardless of the contents. The publication process description indicates when and why the publication rate changes.

IEC 61850 GOOSE objects can quickly and conveniently transfer status, controls, and measured values between peers on an IEC 61850 network. Configure SEL devices to respond to GOOSE messages from other network devices with Architect. Also, configure outgoing GOOSE messages for SEL devices in Architect. See the Architect instruction manual or online help for more information.

Each IEC 61850 GOOSE sender includes a text identification string (GOOSE Control Block Reference), APP ID field, and an Ethernet multicast group address, in each outgoing message. Some devices that receive GOOSE messages use the text identification and multicast group to identify and filter incoming GOOSE messages. The SEL-651R-2 uses only the APP ID and multicast group to identify and filter incoming GOOSE messages.

Virtual bits (VB001–VB128) are control inputs that you can map to GOOSE receive messages by using Architect. If you intend to use any SEL-651R-2 virtual bits for controls, you must create SELOGIC control equations to define these operations.

File Services

The Ethernet File System allows reading or writing data as files. The File System supports FTP and MMS File Transfer. The File System provides:

> ➤ A means for the device to transfer data as files.

> ➤ A hierarchal file structure for the device data.

The SEL-651R-2 supports MMS File transfer with or without authentication. The service is intended to support:

> ➤ CID file download and upload

> ➤ Event report retrieval (from the COMTRADE directory)

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MMS File Services are enabled or disabled via Port 5 setting EMMSFS. Permissions for the 2AC level apply to MMS File Services requests. All files and directories that are available at Access Level 2 via any supported file transfer mechanism (FTP, file read/write, etc.) are also available for transfer via MMS File Services.

SCL Files

Substation Configuration Language (SCL) is an XML-based configuration language used to support the exchange of database configuration data between different tools, which may come from different manufacturers. There are four types of SCL files:

➤ Intelligent Electronic Device (IED) Capability Description file (.ICD)

➤ System Specification Description (.SSD) file

➤ Substation Configuration Description file (.SCD)

➤ Configured IED Description file (.CID)

The ICD file describes the capabilities of an IED, including information on LN and GOOSE support. The SSD file describes the single-line diagram of the substation and the required LNs. The SCD file contains information on all IEDs, communications configuration data, and a substation description. The CID file, of which there may be several, describes a single instantiated IED within the project, and includes address information.

Datasets

Datasets are configured using Architect and contain data attributes which represent real data values within the SEL-651R-2 device. See *Logical Nodes* for the logical node tables that list the available data attributes for each logical node and the Relay Word bit mapping for these data attributes. The list of datasets in *Figure L.1* are the defaults for a SEL-651R-2 device. Fourteen datasets are preconfigured with common FCDAs to be used for reporting. One dataset is preconfigured for GOOSE. These datasets can be configured to represent the desired data to be monitored.
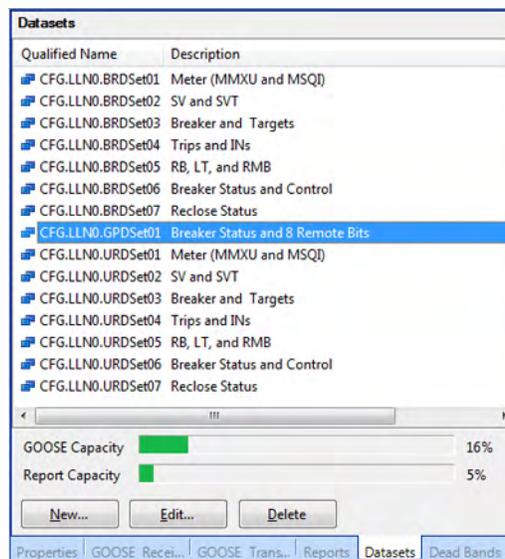
Figure L.1   SEL-651R-2 Datasets

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Within Architect, IEC 61850 datasets have the following purposes:

➤ GOOSE: You can use the predefined dataset (GPDSet01), edit existing datasets, or create new datasets for outgoing GOOSE transmission.

➤ Reports: Fourteen predefined datasets (BRDSet01–BRDSet07 and URDSet01–URDSet07) correspond to the default seven buffered and seven unbuffered reports. Note that you cannot change the number (14) or type of reports (buffered or unbuffered) within Architect. However, you can alter the data attributes that a dataset contains and so define what data an IEC 61850 client receives with a report.

➤ MMS: You can use predefined or edited datasets, or you can create new datasets to be monitored by MMS clients.

NOTE: Do not edit the dataset names used in reports. Changing or deleting any of those dataset names will cause a failure in generating the corresponding report.

Reports

The SEL-651R-2 implements the IEC 61850 reporting service as part of its server functionality. The reporting service includes the functionality necessary to configure, manage, and send IEC 61850 buffered and unbuffered reports as unsolicited reports, periodic integrity reports, or as the result of a general interrogation. See the IEC 61850 Standard, Part 7-1, Section 6.4.3.3, Part 7-2, Section 14, and Part 8-1, Section 17 for more details on the IEC 61850 reporting service.

A total of 14 predefined reports (7 buffered and 7 unbuffered) are supported. The predefined reports and the datasets assigned to each report are shown in *Figure L.2* and are available by default via IEC 61850. The number of reports (14), the dataset assigned to each report, and the type of reports (buffered or unbuffered) cannot be changed. However, by using Architect, you can reallocate data within each report dataset to present different data attributes for each report beyond the predefined datasets.

ID	Name	Description	Dataset
URep07	URep07	Predefined Unbuffered Report 07	URDSet07
URep06	URep06	Predefined Unbuffered Report 06	URDSet06
URep05	URep05	Predefined Unbuffered Report 05	URDSet05
URep04	URep04	Predefined Unbuffered Report 04	URDSet04
URep03	URep03	Predefined Unbuffered Report 03	URDSet03
URep02	URep02	Predefined Unbuffered Report 02	URDSet02
URep01	URep01	Predefined Unbuffered Report 01	URDSet01
BRep07	BRep07	Predefined Buffered Report 07	BRDSet07
BRep06	BRep06	Predefined Buffered Report 06	BRDSet06
BRep05	BRep05	Predefined Buffered Report 05	BRDSet05
BRep04	BRep04	Predefined Buffered Report 04	BRDSet04
BRep03	BRep03	Predefined Buffered Report 03	BRDSet03
BRep02	BRep02	Predefined Buffered Report 02	BRDSet02
BRep01	BRep01	Predefined Buffered Report 01	BRDSet01

Figure L.2   SEL-651R-2 Predefined Reports

For each buffered report control block (BRCB), there can be just one client association (i.e., only one client can be associated to a BRCB at any given time). The client association occurs when the client enables the RptEna attribute of the BRCB. Once enabled, the associated client has exclusive access to the BRCB until the connection is closed or the client disables the

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RptEna attribute. Once enabled, all unassociated clients have read only access to the BRCB and the associated client will be the only client that receives buffered report data. The BRCB parameters are shown in *Table L.5*.

Table L.5   Buffered Report Control Block Client Access

RCB Attribute	User Changeable (Report Disabled)	User Changeable (Report Enabled)	Default Values
RptId	YES		BRDSet01–BRDSet07
RptEna	YES	YES	FALSE
OptFlds	YES		seqNum
			timeStamp
			dataSet
			reasonCode
			entryID
BufTm	YES		500
TrgOps	YES		dchg
			qchg
			period
IntgPd	YES		0
GI	YES[a,b]	YES[a]	FALSE
PurgeBuf	YES[a]		FALSE
EntryId	YES		0

[a] Exhibits a pulse behavior. Write a one to issue the command. Once command is accepted will return to zero. Always read as zero.

[b] When disabled, a GI will be processed and the report buffered if a buffer has been previously established. A buffer is established when the report is enabled for the first time.

Once a BRCB has been enabled, a report buffer is established. The buffer is sized to contain 10 complete reports with a size hard coded in the SEL-651R-2 ICD file. However, in cases where the report dataset is smaller than the allowed maximum size, or when the encoded report does not include the entire dataset, as many as 200 reports may appear in the buffer. Reports are maintained in the buffer regardless of having been sent. This allows the client to retrieve reports that have already been sent by writing an EntryID prior to the current EntryID.

When a client sets the RptEna attribute of a BRCB to true, all new reports contained in the report buffer, starting from the buffer entry following the EntryID attribute specified in the BRCB until the most current buffered report, are sent. At this time, new reports will be sent as required by normal report processing. This behavior allows the client to write the last received EntryID to the BRCB before enabling the report in an attempt to retrieve all report entries that were lost during a lapse in the client association.

When insertion of a new report into a report buffer would cause the buffer size to be exceeded, the oldest entries in the buffer are discarded until the buffer size has been reduced sufficiently to allow the new report to be added to the buffer. If the reports removed from the buffer have not yet been sent to the client, a buffer overflow indication is set in the next report queued for transmission to indicate that reports have been lost. The buffer overflow indication is reported in the BufOvfl field of the report if the buffer overflow OptFld has been enabled in the BRCB.

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The contents of a report buffer are deleted when a PurgeBuf is commanded by a client. As noted in the requirements for the BRCB, the PurgeBuf can only be commanded when the report is disabled. The buffer overflow indication shall be cleared when the client commands a PurgeBuf. Additionally, the buffered reports will be purged if any of the BRCB attributes RptID, DatSet, BufTm, TrgOps, or IntgPd are modified by the client while the report is disabled.

For each unbuffered control block (URCB), there can be as many as seven client associations. The client association occurs when the client enables the RptEna attribute of the URCB. Once enabled, each client has independent access to its instance of the URCB and all associated clients receive unbuffered report data. The URCB parameters are shown in *Table L.6*.

Although the URCB Resv attribute is writable, the SEL-651R-2 does not support reservations. Writing any field of the URCB causes the client to obtain their own instance of the URCB—in essence, acquiring a reservation.

Table L.6   Unbuffered Report Control Block Client Access

RCB Attribute	User Changeable (Report Disabled)	User Changeable (Report Enabled)	Default Values
RptId	YES		URDSet01–URDSet07
RptEna	YES	YES	FALSE
Resv	YES		FALSE
OptFlds	YES		seqNum
			timeStamp
			dataSet
			reasonCode
BufTm	YES		250
TrgOps	YES		dchg
			qchg
			period
IntgPd	YES		0
GI		YES[a]	0

[a] Exhibits a pulse behavior. Write a one to issue the command. Once command is accepted will return to zero. Always read as zero.

NOTE: The TrgOp data update is not supported by the SEL-651R-2 device.

The IEC 61850 standard defines the trigger options (TrgOp) of data change, quality change, and data update. These TrgOps allow reports to be filtered to report only changes associated with the selected TrgOps. Additionally, each of these TrgOps is only associated with or valid for certain data attributes. The valid TrgOps for any given data attribute is described in the Common Data Class (CDC) Descriptions contained within the IEC standard, Part 7-3.

When a client has enabled the RptEna attribute of a BRCB or URCB and any of the data change or quality change TrgOps are enabled within the same BRCB or URCB, the SEL-651R-2 sends an unsolicited report to that client upon detecting a change on an FCDA with a reason corresponding to one of the enabled TrgOps. The unsolicited report contains only those FCDAs that have been detected to have changed for a reason corresponding to one of the enabled TrgOps.

When a client has enabled the RptEna attribute of a BRCB or URCB and that same client writes a non-zero value to the GI attribute of the BRCB or URCB, a report is sent to that client containing the current data for all FCDA within the report dataset.

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When a client has enabled the RptEna attribute and the IntgPd attribute of the BRCB or URCB is set to a non-zero value, and the TrgOps period attribute is enabled, a report is sent to that client containing the current data for all FCDAs within the report dataset upon detecting an expiration of the IntgPd.

FCDA updates are serviced every 500 ms. The client can set the report control block (BRCB or URCB) IntgPd to any value greater than 500 ms with a resolution of 1 ms. However, the integrity report is only sent when the period has been detected as having expired. The new IntgPd will begin at the time that the current report is serviced.

BufTm timers are part of the report control block (BRCB and URCB). The purpose of the BufTm timers is to buffer mutually exclusive data change events over a period of time and send these changes out as one report. Each client that enables an unbuffered report may have a BufTm value independent of other clients that enable the same unbuffered report. This does not apply to buffered reports because only one client can enable a buffered report.

Report data are updated every 500 ms. Setting BufTm less than 500 ms does not result in data changes from multiple scans being buffered into a single report. For a BRCB with a non-zero BufTm attribute, a BufTm timer is started upon receiving notification of the change of a member of a dataset, and all changes received during BufTm are combined into a single report to be buffered and sent at the expiration of BufTm. If a second internal notification of the same member of a dataset has occurred prior to the expiration of BufTm, a report is immediately buffered and sent.

Reports are formatted as specified in the IEC 61850 standard, Part 7-2, Table 24. The report EntryID attribute is incremented each time a report is built.

Supplemental Software

Examine the data structure and values of the supported IEC 61850 LNs with an MMS browser such as MMS Object Explorer and AX-S4 61850 from Sisco, Inc.

The settings needed to browse an SEL-651R-2 with an MMS browser are shown below.

OSI-PSEL (Presentation Selector)	00000001
OSI-SSEL (Session Selector)	0001
OSI-TSEL (Transport Selector)	0001

Time Stamps and Quality

In addition to the various data values, the two attributes q (quality) and t (time stamp) are available at any time. The time stamp is determined when a data or quality change is detected and is UTC reported as the Second of Century since January 1, 1970, plus fractional seconds.

The time stamp is applied to all data and quality attributes (Boolean, Bstrings, Analogs, etc.) in the same fashion when a data or quality change is detected.

Functionally constrained data attributes (FCDA) mapped to points assigned to the SER report have SER-accuracy time stamps for data change events. To ensure that you will get SER-quality timestamps for changes to certain points, you must include those points in the SER report. All other FCDAs are scanned for data changes on a 1/2-second interval and have 1/2-second time-stamp accuracy. See *SET Command (Change Settings) on page 10.67* for information on programming the SER report.

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The SEL-651R-2 uses GOOSE quality attributes to indicate the quality of the data in its transmitted GOOSE messages. Under normal conditions, all attributes are zero, indicating good quality data. Internal status indicators provide the information necessary for the device to set these attributes. If the device becomes disabled, as shown via status indications (e.g., an internal self-test failure), the SEL-651R-2 will stop transmitting GOOSE messages.

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SEL devices support GOOSE processing as defined by IEC 61850-7-1:2003(E), IEC 61850-7-2:2003(E), and IEC 61850-8-1:2004(E).

Four times per power system cycle, the relay reads inputs, processes protection algorithms, and controls outputs. Each of these quarter-cycle periods is called a processing interval. GOOSE messages are considered inputs and outputs and are processed with the same priority as contact inputs, contact outputs, and protection algorithms. The relay processes incoming GOOSE messages near the beginning of every processing interval just after it reads the contact inputs, and processes outgoing GOOSE messages near the end of every processing interval after it controls the contact outputs.

GOOSE Construction Tips

➤ Quality bit strings published from SEL relays are not generally useful in determining the quality of associated data because the SEL IEDs suspend publication of GOOSE messages if any quality attribute fails. Therefore, receipt of the message indicates that all quality attributes are normal. Do not include quality bit strings in published GOOSE messages unless required by some other type of IED.

➤ Make GOOSE publications as small as possible. Include in the GOOSE publication only the information required by subscribing relays.

➤ Give higher VLAN priority tags to more important GOOSE. This allows the network to preferentially forward those GOOSE to the subscribers, and also gives a subscribing SEL-651R-2 an indication that the more important GOOSE should be decoded before lower priority GOOSE.

➤ The relay supports no more than 128 unique Boolean elements mapped between all GOOSE publications.

GOOSE Construction Example

The dataset shown in *Figure L.3* is used in a GOOSE publication from an SEL-651R. It contains information that is not necessary to a subscribing relay. For example, the dataset contains the Mod, Beh, and Health fields (ANN.OUT1GGIO3.Mod.*, ANN.OUT1GGIO3.Beh.*, and ANN.OUT1GGIO3.Health.*) from the OUT1 logical node. In this case, the information in those fields is of no use to a subscribing relay. Also, each of the two OUT1 statuses contained in the dataset are accompanied by their corresponding quality bit strings and time stamps (ANN.OUTGGIO3.Ind01.q, ANN.OUT1GGIO3.Ind01.t, etc.). If the quality field is included in a GOOSE, then the subscribing device must spend additional processing time decoding that quality bit string and applying it to the associated data.

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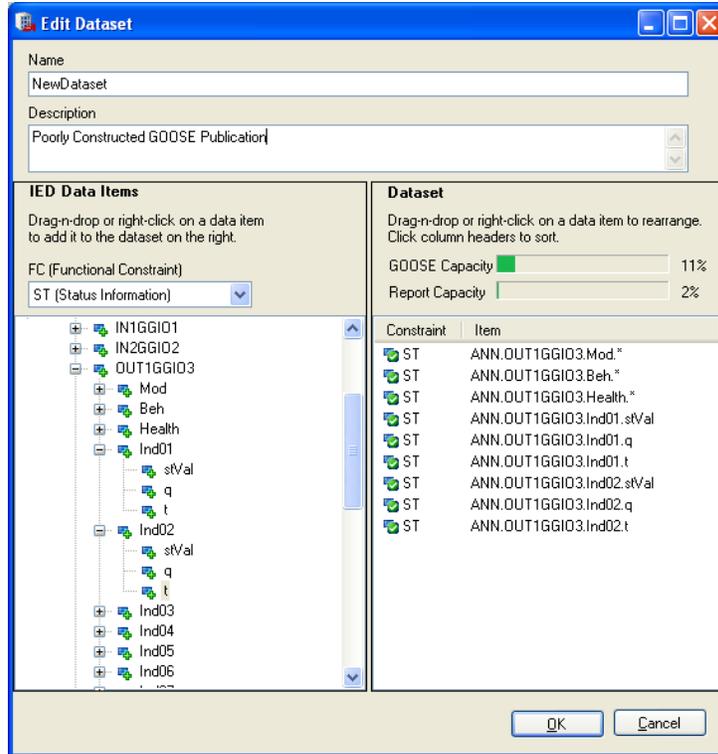
Figure L.3   Example of a Poorly Constructed GOOSE Dataset

Figure L.4 shows an example of a GOOSE publication from an SEL-651R with better construction. This dataset contains only the information required by the subscribing relay(s) to decode the OUT1 status from the publishing SEL-651R (ANN.OUT1GGIO3.Ind01.stVal and ANN.OUT1GGIO3.Ind02.stVal) and does not include quality bit strings or time stamps.

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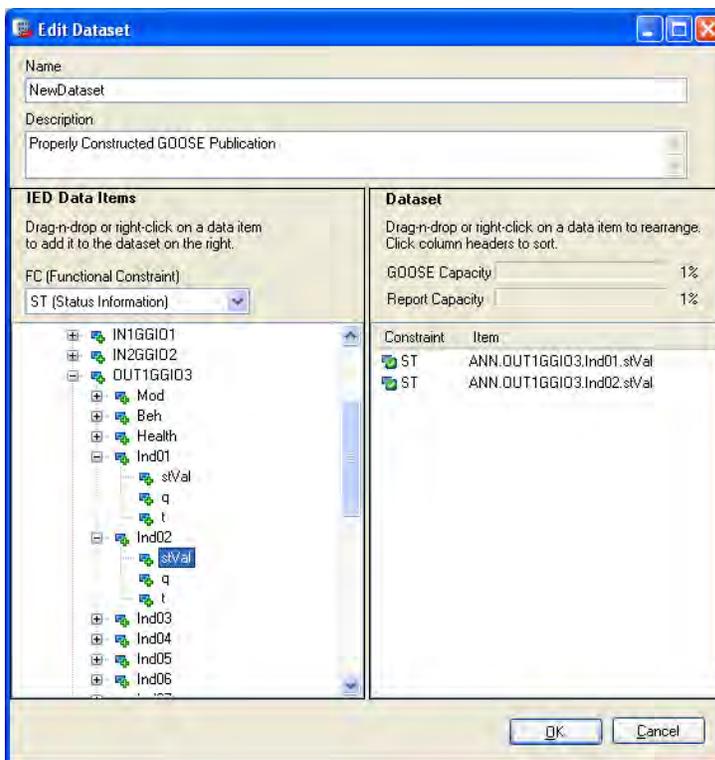
Figure L.4   Example of a Properly Constructed GOOSE Dataset

GOOSE Receive and Transmit Capacity

Each processing interval, the relay processes received and transmitted GOOSE messages. The relay assigns each received and transmitted message a point value at configuration time (when the relay receives and parses the CID file). The point values for various messages are calculated as described in *GOOSE Subscription (Receive) Processing on page L.13* and *GOOSE Publication (Transmit) Processing on page L.18*. The number of points that can be received per processing interval is 80 and that can be transmitted per processing interval is 40.

A single GOOSE receive subscription shall not be allowed to exceed 112 points, and a single GOOSE transmit publication shall not be allowed to exceed 64 points. If a receive subscription exceeds 80 points or a transmit publication exceeds 40 points, 2 processing intervals are necessary to process the message.

GOOSE Subscription (Receive) Processing

The relay supports as many as 24 GOOSE subscriptions. GOOSE messages which arrive at the relay are subjected to the following processing steps when port setting EGSE is set to Y.

Filter

Each message is inspected for proper multicast MAC address and GOOSE App ID. If those parameters match values expected by the relay for one of as many as 24 GOOSE subscriptions, then the message is passed on to the next level of processing. Otherwise the message is discarded. Each message on the LAN must have a unique combination of multicast MAC address and GOOSE App ID.

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Buffer

The relay retains the most recent arrival for each of as many as 24 subscriptions. If a subsequent GOOSE arrives for a subscription that already has a message buffered, then the earlier arrival is discarded.

Decode

The decoding process consists of several stages. Each decoding stage has an associated processing cost, and the relay limits the total cost of all received GOOSE decoding to reserve enough time to process protection algorithms, programmable logic, outputs, outgoing GOOSE messages, etc. Some messages will be decoded during subsequent processing intervals if they are in the receive buffers at the beginning of the processing interval and cost more than 80 points to decode when synchrophasors are disabled (Global setting EPMU := N) or more than 40 points to decode when synchrophasors are enabled (Global setting EMPU := Y). The sections below describe how the relay scores each message as it is decoded and assume that synchrophasors are not enabled (Global setting EPMU := N).

Header Decoding

Each message contains a header that indicates the status of the message. The relay ignores the remainder of the message if any of four indicators in the message header are true:

➤ Configuration Mismatch. The configuration number of the incoming GOOSE changes.

➤ Needs Commissioning. This Boolean parameter of the incoming GOOSE message is true.

➤ Test Mode. This Boolean parameter of the incoming GOOSE message is true.

➤ State Number. This parameter is the same as the last time the message was decoded. State Number increments when the contents of the message change, so if the State Number is unchanged, there is no reason to decode the rest of the message.

Whether the header indicates the message should be subjected to further decoding or ignored, decoding the header always costs eight points.

Message Body Decoding

The cost of decoding the message body depends on the structure of the message. *Table L.7* shows the cost of each type of data in the message body and the cost of decoding the message header.

Table L.7   Point Cost of Decoding GOOSE Messages (Sheet 1 of 2)

Data Type	Description	Point Value	Comments
	Message header	8	Each message counts for at least eight points, regardless of the content of the message.
Message Quality Bit	A Boolean value created in the receiving relay indicating the status of the received message	0	This bit can always be mapped to local virtual bits for zero cost.
Boolean	A Boolean value mapped to a virtual bit	1	Boolean values not mapped to local virtual bits count as zero points.

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Table L.7   Point Cost of Decoding GOOSE Messages (Sheet 2 of 2)

Data Type	Description	Point Value	Comments
Quality Bit String	A quality field associated with a data item, where the data item contains data mapped to a virtual bit	1	Quality fields not associated with a data item containing data that are mapped to a virtual bit count as zero points.
Time	Data item time stamp	0	Some data items are accompanied by a time stamp. The time stamp is never used or decoded by the SEL-651R-2. It counts as zero points.
Bit String (other than Quality)	Several bits packed together in the same data item, where at least one of the bits is mapped to a virtual bit	1 for the bit string, plus 1 per bit in the bit string mapped to a virtual bit	Bit strings are often used for breaker position. A bit string that contains no bits mapped to a virtual bit counts as zero points.
Floating Point	Either single or double precision floating point values	0	Floating point values always count as zero points.
Other types of data	Any data type other than those shown above		The relay will correctly process any valid GOOSE message to which it subscribes. However, some data types are costly for the relay to process even if the data are not used by the receiving relay. Contact the SEL factory if you must configure the SEL-651R-2 to subscribe to GOOSE messages with data types other than those listed above.

Message Point Value Calculation Example

Assume the relay subscribes to a message with 10 Boolean values, five of which are mapped to local virtual bits. Each of the 10 Boolean values is accompanied by a quality indicator. The message also contains one breaker position (a two-bit string) with accompanying quality indicator and time stamp. The two bits of breaker position are mapped to two virtual bits in the SEL-651R-2. The message also contains two single precision floating point numbers. In addition, the message quality bit is mapped to a local virtual bit.

The dataset for such a message is shown in *Figure L.5*. As described above, not all items from the dataset are mapped to local resources within the receive SEL-651R-2. Similar to the example GOOSE shown in *Figure L.3*, the GOOSE message shown in *Figure L.5* is poorly constructed and is shown only as an example of a GOOSE message containing several types of data.

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Figure L.5   Example Receive GOOSE Dataset

The score for this message is as follows:

➤ 8 points for the message

➤ 0 points for the message quality bit

➤ 5 points for 5 mapped Booleans

➤ 5 points for 5 quality fields associated with data items that have data mapped to local virtual bits

➤ 3 points total for the breaker position indication (one for the bit string and one each for the two bits in the string)

➤ 1 point for the quality bit string associated with the breaker position bit string

➤ 0 points for the breaker position bit string time stamp

➤ 0 points for the single precision floating-point numbers

   22 total points in this message

Examples of GOOSE Subscription (Receive) Processing

The following examples assume that synchrophasors are not enabled (EPMU := N), so the relay is guaranteed to process as many as 80 points in a processing interval. For example, assume the relay subscribes to messages as shown in *Table L.8*.

Table L.8   Scores for Subscribed Messages Used in Example (Sheet 1 of 2)

Subscription Number	Message Score
1	10
2	10
3	9

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Table L.8   Scores for Subscribed Messages Used in Example (Sheet 2 of 2)

Subscription Number	Message Score
4	12
5	10
6	10
7	9
8	10
Total	**80**

The total score for all of the subscribed messages is 80 points. Even if every message in *Table L.8* arrives every processing interval, and even if the header information from every message indicates that the message must be decoded, the relay is guaranteed to process every message, update the local virtual bits, and use those updated values in programmable logic during that processing interval.

Next, assume that the relay subscribes to messages as shown in *Table L.9*.

Table L.9   Scores for Subscribed Messages Used in Example

Subscription Number	Message Score
1	16
2	20
3	10
4	28
5	16
6	24
7	12
8	10
9	10
Total	**146**

The total score for all of the subscribed messages is 146 points. Notice that if all of the message points are because of message headers and mapped Boolean values, then these nine messages represent 74 Boolean values mapped to local virtual bits. Assume every message arrives during the same processing interval, but messages 1–6 are repeats of messages processed earlier (i.e., those messages do not have changed state numbers). Those six repeated messages count as 8 points each, or 48 points total. Assume messages 7, 8, and 9 each contain changed data, so the state number has incremented since the last time the message was processed. The combined score for messages 7, 8, and 9 is 32 points. So, the total score for all messages is 80 points. In this case the relay will process all messages in a single processing interval.

Finally, assume that the relay subscribes to messages as shown in *Table L.10*.

Table L.10   Scores for Subscribed Messages Used in Example (Sheet 1 of 2)

Subscription Number	Message Score
1	16
2	20
3	10

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Table L.10   Scores for Subscribed Messages Used in Example (Sheet 2 of 2)

Subscription Number	Message Score
4	16
5	16
6	10
7	12
8	28
9	16
10	20
11	10
12	16
13	10
14	10
15	12
16	16
17	20
18	10
19	16
20	16
21	10
22	12
23	28
24	16
Total	**366**

The total combined score for all of the subscribed messages is 366 points. As long as messages totaling 80 or fewer points arrive each processing interval, the relay will process all received messages every processing interval. If messages totaling more than 80 points arrive in any processing interval, then the relay will process messages totaling 80 or fewer points, and will continue processing during the next quarter-cycle processing interval.

GOOSE Publication (Transmit) Processing

The relay supports as many as eight GOOSE publications. Each publication can contain data from any logical node in the relay. The relay supports no more than 128 unique Boolean elements mapped between all GOOSE publications. The relay transmits a message from each publication soon after initialization (e.g., after startup). Near the end of each processing interval, the relay transmits one message from as many publications as possible in which the state numbers have incremented. The relay then transmits one message from as many publications as possible in which the transmit interval timers have expired.

State Number

The relay maintains a count of the number of times the contents of a publication have changed. The count is called the state number. If the state number increments, then the relay transmits a message from that publication, as discussed below.

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Transmit Interval

If the data contained in the messages do not change (i.e., if the state number does not increase), then the relay retransmits the message based on the configured MinTime and MaxTime settings from the CID file. The first transmission occurs immediately upon the trigger occurring. The second occurs approximately MinTime later. The third occurs approximately MinTime after the second. The fourth occurs twice MinTime after the third. All subsequent transmissions occur at the MaxTime interval. For example, if MinTime is 4 ms and MaxTime is 100 ms, the intervals between transmissions will be 4 ms, 4 ms, 8 ms, and then 100 ms. If MaxTime is not greater than twice MinTime, the third and all subsequent transmissions will occur at the MaxTime interval. The MinTime and MaxTime intervals can be configured for each GOOSE transmit message by using Architect. The time-to-live reported in the first two messages is three times MinTime. The time-to-live in all subsequent messages is two times MaxTime.

The total number of message transmissions possible during each processing interval because of either state number changes or transmit interval timeout depends on the structure of the messages to be transmitted and whether synchrophasors are enabled. The relay assigns each message a point value at configuration time (when the relay receives and parses the CID file). At each processing interval, the relay processes and transmits messages totaling as many as 40 points if synchrophasors are not enabled (Global setting EPMU := N) or 20 points if synchrophasors are enabled (Global setting EMPU := Y). Some messages available for transmission because their transmit intervals have timed out or because there state numbers have incremented will be transmitted on subsequent processing intervals. These messages either total more than 40 points for disabled synchrophasors (Global setting EPMU := N) or 20 points if synchrophasors are enabled (Global setting EMPU := Y). *Table L.11* shows the point value for different parts of the GOOSE message.

Table L.11   Score For Data Types Contained in Published Messages

Data Type	Description	Point Value	Comments
	Message	8	Each message counts at least 8 points every time it is transmitted, regardless of the content of the message. A message that is not transmitted counts as zero points.
Quality Bit String	A quality field associated with a data item.	0	Transmit quality is always zero.
Boolean, Time, Bit Strings (Other than Quality), Integer (INT8), Floating Point, Enumerations		1	Each of these data types costs one point to process and transmit.
Other Types of Data	Types of data other than those mentioned above.		The relay will correctly process and transmit any valid GOOSE message. However, some data types are costly for the relay to process. Contact the SEL factory if you must configure the SEL-651R-2 to publish GOOSE messages with data types other than those listed above.

Message Point Value Calculation Example

Assume the relay publishes a message with 10 Boolean values. Each of the 10 Boolean values is accompanied by a quality indicator and a time stamp. The message also contains two single precision floating-point numbers with associated time stamps.

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The dataset for such a message is shown in *Figure L.6*. Similar to the example GOOSE shown in *Figure L.3*, the GOOSE message shown in *Figure L.6* is poorly constructed and is shown only as an example of a GOOSE message containing several types of data.

Figure L.6   Example Transmit GOOSE Dataset

The score for this message is as follows:

➤ 8 points for the message

➤ 10 points for 10 Boolean values

➤ 0 points for 10 quality bit strings associated with the Boolean values

➤ 10 points for 10 time stamps associated with the Boolean values

➤ 2 points for 2 single precision floating-point numbers

➤ 2 points for 2 time stamps associated with the single precision floating-point numbers

32 total points in this message

Message Transmission Example

Assume the relay publishes four GOOSE messages as shown in *Table L.12*.

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Table L.12 Scores for Published Messages Used In Example

Publication Number	Message Score
1	10
2	11
3	9
4	10
Total	**40**

The total score for all publications in this example is 40 points. The relay can process and transmit all messages every processing interval if required, assuming that synchrophasors are not enabled in the device.

Next assume the relay publishes messages as shown in *Table L.13*.

Table L.13 Scores for Published Messages Used In Example

Publication Number	Message Score
1	32
2	40
3	20
4	32
5	32
6	20
7	14
8	10
Total	**200**

The total score for all publications in this example is 200 points. If messages totaling more than 40 points are due to be transmitted in any single processing interval, then the relay will transmit messages until the next message transmitted would cause the total score for that processing interval to exceed 40 points. The relay will then continue transmitting during the next quarter-cycle processing interval.

IEC 61850 Configuration

Settings

Table L.14 lists IEC 61850 settings. These settings are only available if your device includes the optional IEC 61850 protocol.

Table L.14 IEC 61850 Settings

Label	Description	Range	Default
E61850	IEC 61850 interface enable	Y, N	N
EGSE[a]	IEC 61850 GSE message enable	Y, N	N
EMMSFS[a]	Enable MMS File Services	Y, N	N

[a] Settings EGSE and EMMSFS are hidden when E61850 is set to N.

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Devices ordered with the optional IEC 61850 protocol are delivered with a default CID file loaded on the device. The file is named SET_61850.CID. To make the device communicate with other devices over IEC 61850, the device must be configured.

Configure all other IEC 61850 settings, including subscriptions to incoming GOOSE messages, with Architect.

When IEC 61850 is enabled (E61850 = Y), the device parses the CID file to determine the device IEC 61850 configuration. When EGSE = Y, the device begins transmitting GOOSE messages and receiving GOOSE subscriptions configured in the CID file. Issuing the ASCII **GOO** command provides GOOSE status information. See *GOOSE Command on page 10.51* for a detailed description of the **GOO** Command.

NOTE: Firmware versions previous to R404 will display `PARSE FAILURE` in the iedName, type, and configVersion fields of the ID Command if the CID file is invalid. No GOOSE messages will be transmitted and MMS will be unavailable if `PARSE FAILURE` is displayed in these fields.

If the device does not have a valid IEC 61850 configuration, it will not send or receive any IEC 61850 communications. Issuing the ASCII **ID** command provides information on the status of the CID file. If there is a problem with the CID file, the iedName, type, and configVersion fields of the **ID** command response will display "PARSE FAILURE" as shown below.

```
=>>ID <Enter>

"FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","0957"
"BFID=SLBT-3CF1-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","097A"
"CID=B0F0","0265"
"DEVID=STATION A","049C"
"DEVCODE=56","0312"
"PARTNO=0651R221XBAXAC2123B4XX","07D9"
"SERIALNO=000000000000000","05DA"
"CONFIG=11242200","03EF"
"SPECIAL=11000","03A0"
"iedName=PARSE FAILURE","0703"
"type=PARSE FAILURE","0612"
"configVersion=PARSE FAILURE","09AC"

=>>
```

NOTE: MMS File Services can be used to load a new CID file only if EMMSFS := Y and a valid CID file is currently loaded into the device. If no CID file is currently loaded, only FTP or Architect can load a valid CID file.

You will need to load a valid CID file into the device by using FTP, Architect, or MMS File Services. When loading a new CID file, Architect returns an error message if the file is not accepted. If using FTP or MMS File Services to load a new CID file, follow the write operation with a read of the ERR.TXT file from the device to verify successful transmission and configuration of the new CID file. If the file transfer fails or the device detects an invalid CID file, the ERR.TXT file will contain an error message. If the file is blank (length is zero), then the new CID file was accepted by the device. If a failure occurs, the CID file that you previously loaded in the device will be retained. The new CID file will replace the current CID file only if the transfer and configuration of the new CID file is successful.

Once a valid CID file is loaded into the device, the ID command response should look like that shown below with the iedName, type, and configVersion fields revealing the proper configured information. The iedName displays the configured IED name which can be modified by using Architect. The type and configVersion fields cannot be modified and represent the relay type and the ICD file version used for the configured CID file.

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```
=>>ID <Enter>

"FID=SEL-651R-2-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","0957"
"BFID=SLBT-3CF1-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","097A"
"CID=B0F0","0265"
"DEVID=STATION A","049C"
"DEVCODE=56","0312"
"PARTNO=0651R221XBAXAC2123B4XX","07D9"
"SERIALNO=000000000000000","05DA"
"CONFIG=11242200","03EF"
"SPECIAL=01211","03A3"
"iedName=SEL_651R_1","0621"
"type=SEL_651R_2","0531"
"configVersion=ICD-651R-Rxxx-Vx-Zxxxxxx-Dxxxxxxxx","0D78"

=>>
```

Architect

The Architect software enables protection and integration engineers to design and commission IEC 61850 substations containing SEL IEDs.

Engineers can use Architect to:

- ➤ Organize and configure all SEL IEDs in a substation project.

- ➤ Configure incoming and outgoing GOOSE messages.

- ➤ Edit and create GOOSE datasets.

- ➤ Read non-SEL IED Capability Description (ICD) and Configured IED Description (CID) files and determine the available IEC 61850 messaging options.

- ➤ Use or edit preconfigured datasets for reports.

- ➤ Enable/disable MMS authentication.

- ➤ Configure MMS inactivity timeout.

- ➤ Load IEC 61850 CID files into SEL IEDs.

- ➤ Generate ICD and CID files that will provide SEL IED descriptions to other manufacturers' tools so they can use SEL GOOSE messages and reporting features.

Architect provides a Graphical User Interface (GUI) for engineers to select, edit, and create IEC 61850 GOOSE messages important for substation protection, coordination, and control schemes. Typically, the user first places icons representing IEDs in a substation container, then edits the outgoing GOOSE messages or creates new ones for each IED. The user can also select incoming GOOSE messages for each IED to receive from any other IEDs in the domain.

Some measured values are reported to IEC 61850 only when the value changes beyond a defined dead-band value. Architect allows a dead band to be changed during the CID file configuration. Check and set the dead-band values for your particular application when configuring the CID file for a device.

Architect has the capability to read other manufacturers' ICD and CID files, enabling the user to map the data seamlessly into SEL IED logic. See the Architect online help for more information.

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SEL ICD File Versions

Architect version R.1.1.69.0 and later supports multiple ICD file versions for each type of IED in a project. Because relays with different firmware versions may require different CID file versions, users can manage the CID files of all IEDs within a single project.

Please ensure that you work with the appropriate version of Architect relative to your current configuration, existing project files, and ultimate goals. If you want the best available IEC 61850 functionality for your SEL relay, obtain the latest version of Architect and select the appropriate ICD version(s) for your needs.

Architect generates CID files from ICD files so the ICD file version Architect uses also determines the CID file version generated. As of this writing, Architect comes with several versions of the SEL-651R-2 ICD file. Two versions are compatible with the SEL-651R-2 for use on new or existing projects. These versions are listed below.

SEL-651R2 File Version 005 (651R2 Firmware R404 or higher): File supports MMS Authentication, MMS file transfer, including COMTRADE events and CID files. It supports seven client connections.

SEL-651R2 File Version 004 (651R2 Firmware R400 or higher): This file supports six client connections and does not support MMS Authentication. Ensure that you use the appropriate version for your IEC 61850 project requirements.

Logical Node Extensions

The following Logical Nodes and Data Classes were created in this device as extensions to the IEC 61850 standard, in accordance with IEC 61850 guidelines.

Table L.15   New Logical Node Extension

Logical Node	IEC 61850	Description or Comments
Demand Metering Statistics	MDST	Demand and peak demand values for current and energy.

Table L.16   Demand Metering Logical Node Class Definitions (Sheet 1 of 2)

Attribute Name	Attribute Type	Data Source	Explanation	T[a]	M/O/C/E[b]
IEC 61850 Logical Node Class: MDST					
LNName			The name shall be composed of the class name, the LN-Prefix and LN-Instance-ID according to IEC 61850-7-2.		
Data					
Common Logical Node Information					
			LN shall inherit all mandatory data from common Logical Node Class		M
Measured Values					
DmdA.phsA	MV	IADEM	Demand, phase A current		O
DmdA.phsB	MV	IBDEM	Demand, phase B current		O
DmdA.phsC	MV	ICDEM	Demand, phase C current		O
DmdA.neut	MV	INDEM	Demand, neutral current		O
DmdA.res	MV	IGDEM	Demand, residual current		O

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Table L.16   Demand Metering Logical Node Class Definitions (Sheet 2 of 2)

			IEC 61850 Logical Node Class: MDST		
Attribute Name	**Attribute Type**	**Data Source**	**Explanation**	**T**[a]	**M/O/C/E**[b]
DmdA.nseq	MV	3I2DEM	Demand, negative-sequence current		O
PkDmdA.phsA	MV	IAPK	Peak demand, phase A current		O
PkDmdA.phsB	MV	IBPK	Peak demand, phase B current		O
PkDmdA.phsC	MV	ICPK	Peak demand, phase C current		O
PkDmdA.neut	MV	INPK	Peak demand, neutral current		O
PkDmdA.res	MV	IGPK	Peak demand, residual current		O
PkDmdA.nseq	MV	3I2PK	Peak demand, negative-sequence current		O
SupWh	MV	MWH3I	Energy, real (MWh), supply direction toward busbar		O
SupVArh	MV	MVRH3I	Energy, reactive (MVARh), supply direction toward busbar		O
DmdWh	MV	MWH3O	Energy, real (MWh), supply direction away from busbar		O
DmdVArh	MV	MVRH3O	Energy, reactive (MVARh), supply direction away from busbar		O

[a] Transient data objects—the status of data objects with this designation is momentary and must be logged or reported to provide evidence of their momentary state.
[b] M: Mandatory; O: Optional; C: Conditional; E: Extension.

Table L.17   Compatible Logical Node With Enhancements

Logical Node	**IEC 61850**	**Description or Comments**
Metering Statistics	MSTA	This LN is used for metering averages, minima and maxima.

Table L.18   Measurement Logical Node Class Definition (Sheet 1 of 2)

		IEC 61850 Logical Node Class: MSTA		
Data Object Name	**Common Data Class**	**Explanation**	**T**[a]	**M/O/C/E**[b]
LNName		The name shall be composed of the class name, the LN-Prefix and LN-Instance-ID according to IEC 61850-7-2.		
Data				
Common Logical Node Information				
LNName		LN shall inherit all mandatory data from common Logical Node Class		
Measured Values				
MaxA	WYE	Maximum current		E
MinA	WYE	Minimum current		E
MaxPhV1	WYE	Maximum phase-to-ground voltage		E
MaxPhV2	WYE	Maximum phase-to-ground voltage		E
MinPhV1	WYE	Minimum phase-to-ground voltage		E
MinPhV2	WYE	Minimum phase-to-ground voltage		E
MaxVa	MV	Maximum apparent power		O
MinVa	MV	Minimum apparent power		O
AvW	MV	Average real power		O
AvPhW	WYE	Average phase real power		O
MaxW	MV	Maximum real power		O
MinW	MV	Minimum real power		O

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Table L.18   Measurement Logical Node Class Definition (Sheet 2 of 2)

IEC 61850 Logical Node Class: MSTA				
Data Object Name	Common Data Class	Explanation	T[a]	M/O/C/E[b]
MaxVAr	MV	Maximum reactive power		O
MinVAr	MV	Minimum reactive power		O

[a] Transient data objects—the status of data objects with this designation is momentary and must be logged or reported to provide evidence of their momentary state.

[b] M: Mandatory; O: Optional; C: Conditional; E: Extension.

Logical Nodes

Table L.19–Table L.24 show the logical nodes (LNs) supported in the SEL-651R-2 and the Relay Word bits or Measured Values mapped to those LNs.

Table L.19 shows the LNs associated with protection elements, defined as Logical Device PRO. See *Appendix F: Relay Word Bits* and *Appendix G: Analog Quantities* for descriptions.

Table L.19   Logical Device: PRO (Protection) (Sheet 1 of 7)

Logical Node	Attribute	Data Source	Comment
Functional Constraint = CO			
BCACSWI2	Pos.ctlVal	CCA:OCA[a]	A-Phase circuit breaker close/open command (0 opens, 1 closes)
BCBCSWI3	Pos.ctlVal	CCB:OCB[a]	B-Phase circuit breaker close/open command (0 opens, 1 closes)
BCCCSWI4	Pos.ctlVal	CCC:OCC[a]	C-Phase circuit breaker close/open command (0 opens, 1 closes)
BCCSWI1	Pos.ctlVal	CC3:OC3[a]	Three-phase circuit breaker close/open command (0 opens, 1 closes)
Functional Constraint = ST			
A51PTOC5	Op.general	51AT	A-phase time-overcurrent element timed out
A51PTOC5	Str.general	51A	A-phase time-overcurrent element picked up
APIOC25	Op.general	50A1	Level 1 A-phase instantaneous overcurrent element
APIOC28	Op.general	50A2	Level 2 A-phase instantaneous overcurrent element
APIOC31	Op.general	50A3	Level 3 A-phase instantaneous overcurrent element
APIOC34	Op.general	50A4	Level 4 A-phase instantaneous overcurrent element
APIOC37	Op.general	50A	A-phase instantaneous overcurrent element
B51PTOC6	Op.general	51BT	B-phase time-overcurrent element timed out
B51PTOC6	Str.general	51B	B-phase time-overcurrent element picked up
BCACSWI2	OpCls.general	CCA	Asserts for one processing interval for **CLOSE** command execution
BCACSWI2	OpOpn.general	OCA	Asserts for one processing interval for **OPEN** command execution
BCACSWI2	Pos.stVal	SPOA?2:1[b]	Phase A single pole/phase open conditions
BCBCSWI3	OpCls.general	CCB	Asserts for one processing interval for **CLOSE** command execution
BCBCSWI3	OpOpn.general	OCB	Asserts for one processing interval for **OPEN** command execution
BCBCSWI3	Pos.stVal	SPOB?2:1[b]	Phase B single pole/phase open conditions
BCCCSWI4	OpCls.general	CCC	Asserts for one processing interval for **CLOSE** command execution
BCCCSWI4	OpOpn.general	OCC	Asserts for one processing interval for **OPEN** command execution

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Table L.19   Logical Device: PRO (Protection) (Sheet 2 of 7)

Logical Node	Attribute	Data Source	Comment
BCCCSWI4	Pos.stVal	SPOC?2:1[b]	Phase C single pole/phase open conditions
BCCSWI1	OpCls.general	CC3	Asserts for one processing interval for **CLOSE** command execution
BCCSWI1	OpOpn.general	OC3	Asserts for one processing interval for **OPEN** command execution
BCCSWI1	Pos.stVal	3PO?2:1[b]	Three pole open conditions
BPIOC26	Op.general	50B1	Level 1 B-phase instantaneous overcurrent element
BPIOC29	Op.general	50B2	Level 2 B-phase instantaneous overcurrent element
BPIOC32	Op.general	50B3	Level 3 B-phase instantaneous overcurrent element
BPIOC35	Op.general	50B4	Level 4 B-phase instantaneous overcurrent element
BPIOC38	Op.general	50B	B-phase instantaneous overcurrent element
BSASCBR1	AbrAlm.stVal	BCWA	A-Phase breaker wear has reached 100% wear level
BSASCBR1	AbrPrt.instMag.f	WEARA	A-Phase breaker wear percentage
BSASCBR1	ColOpn.stVal	OC3	Asserts for one processing interval for **OPEN** command execution
BSASCBR1	MaxAbrPrt.instMag.f	MAXWEAR	Greatest wear of WEARA, WEARB, or WEARC
BSBSCBR2	AbrAlm.stVal	BCWB	B-Phase breaker wear has reached 100% wear level
BSBSCBR2	AbrPrt.instMag.f	WEARB	B-Phase breaker wear percentage
BSBSCBR2	ColOpn.stVal	OC3	Asserts for one processing interval for **OPEN** command execution
BSBSCBR2	MaxAbrPrt.instMag.f	MAXWEAR	Greatest wear of WEARA, WEARB, or WEARV
BSCSCBR3	AbrAlm.stVal	BCWC	C-Phase breaker wear has reached 100% wear level
BSCSCBR3	AbrPrt.instMag.f	WEARC	C-Phase breaker wear percentage
BSCSCBR3	ColOpn.stVal	OC3	Asserts for one processing interval for **OPEN** command execution
BSCSCBR3	MaxAbrPrt.instMag.f	MAXWEAR	Greatest wear of WEARA, WEARB, or WEARC
BSAXCBR1	CBOpCap.stVal	None	Breaker physical operation capabilities not known to relay
BSAXCBR1	OpCnt.stVal	OPSCTRA	A-Phase operations counter
BSAXCBR1	Pos.stVal	52AA?1:2[b]	A-Phase circuit breaker status
BSBXCBR2	CBOpCap.stVal	None	Breaker physical operation capabilities not known to relay
BSBXCBR2	OpCnt.stVal	OPSCTRB	B-Phase operations Counter
BSBXCBR2	Pos.stVal	52AB?1:2[b]	B-Phase circuit breaker status
BSCXCBR3	CBOpCap.stVal	None	Breaker physical operation capabilities not known to relay
BSCXCBR3	OpCnt.stVal	OPSCTRC	C-Phase operations Counter
BSCXCBR3	Pos.stVal	52AC?1:2[b]	C-Phase circuit breaker status
BSXCBR4	CBOpCap.stVal	None	Breaker physical operation capabilities not known to relay
BSXCBR4	Pos.stVal	52A3P?1:2[b]	Three-phase circuit breaker status
C51PTOC7	Op.general	51CT	C-phase time-overcurrent element timed out
C51PTOC7	Str.general	51C	C-phase time-overcurrent element picked up
CPIOC27	Op.general	50C1	Level 1 C-phase instantaneous overcurrent element
CPIOC30	Op.general	50C2	Level 2 C-phase instantaneous overcurrent element
CPIOC33	Op.general	50C3	Level 3 C-phase instantaneous overcurrent element
CPIOC36	Op.general	50C4	Level 4 C-phase instantaneous overcurrent element
CPIOC39	Op.general	50C	C-phase instantaneous overcurrent element
DPTOF1	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTOF1	Op.general	81D1T	Level 1 definite-time frequency element

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Table L.19   Logical Device: PRO (Protection) (Sheet 3 of 7)

Logical Node	Attribute	Data Source	Comment
DPTOF1	Str.general	81D1	Level 1 instantaneous frequency element
DPTOF2	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTOF2	Op.general	81D2T	Level 2 definite-time frequency element
DPTOF2	Str.general	81D2	Level 2 instantaneous frequency element
DPTOF3	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTOF3	Op.general	81D3T	Level 3 definite-time frequency element
DPTOF3	Str.general	81D3	Level 3 instantaneous frequency element
DPTOF4	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTOF4	Op.general	81D4T	Level 4 definite-time frequency element
DPTOF4	Str.general	81D4	Level 4 instantaneous frequency element
DPTOF5	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTOF5	Op.general	81D5T	Level 5 definite-time frequency element
DPTOF5	Str.general	81D5	Level 5 instantaneous frequency element
DPTOF6	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTOF6	Op.general	81D6T	Level 6 definite-time frequency element
DPTOF6	Str.general	81D6	Level 6 instantaneous frequency element
DPTUF1	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTUF1	Op.general	81D1T	Level 1 definite-time frequency element
DPTUF1	Str.general	81D1	Level 1 instantaneous frequency element
DPTUF2	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTUF2	Op.general	81D2T	Level 2 definite-time frequency element
DPTUF2	Str.general	81D2	Level 2 instantaneous frequency element
DPTUF3	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTUF3	Op.general	81D3T	Level 3 definite-time frequency element
DPTUF3	Str.general	81D3	Level 3 instantaneous frequency element
DPTUF4	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTUF4	Op.general	81D4T	Level 4 definite-time frequency element
DPTUF4	Str.general	81D4	Level 4 instantaneous frequency element
DPTUF5	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTUF5	Op.general	81D5T	Level 5 definite-time frequency element
DPTUF5	Str.general	81D5	Level 5 instantaneous frequency element
DPTUF6	BlkV.stVal	27B81	Undervoltage element for frequency element blocking
DPTUF6	Op.general	81D6T	Level 6 definite-time frequency element
DPTUF6	Str.general	81D6	Level 6 instantaneous frequency element
FLTRDRE1	RcdMade.stVal	FLREP	Event report present
FLTRDRE1	FltNum.stVal	FLRNUM	Event numbers
G51PTOC2	Op.general	51G1T	#1 Ground time-overcurrent element timed out
G51PTOC2	Str.general	51G1	#1 Ground time-overcurrent element picked up
G51PTOC3	Op.general	51G2T	#2 Ground time-overcurrent element timed out
G51PTOC3	Str.general	51G2	#2 Ground time-overcurrent element picked up
GFPIOC46	Op.general	50GF	Forward direction ground overcurrent threshold exceeded

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Table L.19   Logical Device: PRO (Protection) (Sheet 4 of 7)

Logical Node	Attribute	Data Source	Comment
GFRDIR3	Dir.dirGeneral	32GF?0:1	If direction is forward, value is 1, otherwise 0
GFRDIR3	Dir.general	32GF	Forward directional control for ground overcurrent elements
GPIOC10	Op.general	50G3	Level 3 ground instantaneous overcurrent element
GPIOC14	Op.general	50G4	Level 4 ground instantaneous overcurrent element
GPIOC18	Op.general	50G5	Level 5 ground instantaneous overcurrent element
GPIOC2	Op.general	50G1	Level 1 ground instantaneous overcurrent element
GPIOC22	Op.general	50G6	Level 6 ground instantaneous overcurrent element
GPIOC6	Op.general	50G2	Level 2 ground instantaneous overcurrent element
GRPIOC47	Op.general	50GR	Reverse direction ground overcurrent threshold exceeded
GRRDIR4	Dir.dirGeneral	32GR?0:2	If direction is reverse, value is 2, otherwise 0
GRRDIR4	Dir.general	32GR	Reverse directional control for ground overcurrent elements
HIFRDRE2	RcdMade.stVal	HIFLREP	High-impedance event report present
HIFRDRE2	FltNum.stVal	HIFLRNUM	High-impedance event numbers
HIZPHIZ2	Op.general	OREDHIF2	HIF detection
HIZPHIZ2	Op.phsA	HIF2_A	A-phase HIF detection
HIZPHIZ2	Op.phsB	HIF2_B	B-phase HIF detection
HIZPHIZ2	Op.phsC	HIF2_C	C-phase HIF detection
HIZPHIZ2	Str.general	OREDHIF2	HIF detection
HIZPHIZ3	Op.general	50GHIZA	Ground instantaneous overcurrent
HIZPHIZ3	Str.general	50GHIZ	Ground instantaneous overcurrent
INTPTUV23	Op.general	INT3P	Three-phase voltage interruption element
INTPTUV23	Op.phsA	INTA	A-phase voltage interruption element
INTPTUV23	Op.phsB	INTB	B-phase voltage interruption element
INTPTUV23	Op.phsC	INTC	C-phase voltage interruption element
INTPTUV23	Str.general	INT3P	Three-phase voltage interruption element
LAPIOC41	Op.general	50LA	A-phase instantaneous overcurrent element for load detection
LBPIOC42	Op.general	50LB	B-phase instantaneous overcurrent element for load detection
LCPIOC43	Op.general	50LC	C-phase instantaneous overcurrent element for load detection
LOPPTUV1	Op.general	LOP	Internal loss-of-potential element
LOPPTUV1	Str.general	LOP	Internal loss-of-potential element
LPIOC40	Op.general	50L	Phase instantaneous overcurrent element for load detection
N51PTOC8	Op.general	51N1T	#1 Neutral time-overcurrent element timed out
N51PTOC8	Str.general	51N1	#1 Neutral time-overcurrent element picked up
N51PTOC9	Op.general	51N2T	#2 Neutral time-overcurrent element timed out
N51PTOC9	Str.general	51N2	#2 Neutral time-overcurrent element picked up
NPIOC12	Op.general	50N3	Level 3 neutral instantaneous overcurrent element
NPIOC16	Op.general	50N4	Level 4 neutral instantaneous overcurrent element
NPIOC20	Op.general	50N5	Level 5 neutral instantaneous overcurrent element
NPIOC24	Op.general	50N6	Level 6 neutral instantaneous overcurrent element
NPIOC4	Op.general	50N1	Level 1 neutral instantaneous overcurrent element
NPIOC8	Op.general	50N2	Level 2 neutral instantaneous overcurrent element

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Table L.19   Logical Device: PRO (Protection) (Sheet 5 of 7)

Logical Node	Attribute	Data Source	Comment
P51PTOC1	Op.general	51PT	Maximum-phase time-overcurrent element timed out
P51PTOC1	Str.general	51P	Maximum-phase time-overcurrent element picked up
PFRDIR5	Dir.dirGeneral	32PF?0:1	If direction is forward, value is 1, otherwise 0
PFRDIR5	Dir.general	32PF	Forward directional control for phase overcurrent elements
PH3PTOV10	Str.general	3P59Y	Three-phase overvoltage element, Y-terminal
PH3PTOV24	Str.general	3P59Z	Three-phase overvoltage element, Z-terminal
PH3PTUV11	Op.general	3P27Y	Three-phase undervoltage element, Y-terminal
PH3PTUV11	Str.general	3P27Y	Three-phase undervoltage element, Y-terminal
PH3PTUV21	Op.general	3P27Z	Three-phase undervoltage element, Z-terminal
PH3PTUV21	Str.general	3P27Z	Three-phase undervoltage element, Z-terminal
PPIOC1	Op.general	50P1	Level 1 phase instantaneous overcurrent element
PPIOC13	Op.general	50P4	Level 4 phase instantaneous overcurrent element
PPIOC17	Op.general	50P5	Level 5 phase instantaneous overcurrent element
PPIOC21	Op.general	50P6	Level 6 phase instantaneous overcurrent element
PPIOC5	Op.general	50P2	Level 2 phase instantaneous overcurrent element
PPIOC9	Op.general	50P3	Level 3 phase instantaneous overcurrent element
PRRDIR6	Dir.dirGeneral	32PR?0:2	If direction is reverse, value is 2, otherwise 0
PRRDIR6	Dir.general	32PR	Reverse directional control for phase overcurrent elements
Q51PTOC4	Op.general	51QT	Negative-sequence time-overcurrent element timed out
Q51PTOC4	Str.general	51Q	Negative-sequence time-overcurrent element picked up
QFPIOC44	Op.general	50QF	Forward direction negative-sequence overcurrent threshold exceeded
QFRDIR1	Dir.dirGeneral	32QF?0:1	If direction is forward, value is 1, otherwise 0
QFRDIR1	Dir.general	32QF	Forward directional control for negative-sequence overcurrent elements
QPIOC11	Op.general	50Q3	Level 3 negative-sequence instantaneous overcurrent element
QPIOC15	Op.general	50Q4	Level 4 negative-sequence instantaneous overcurrent element
QPIOC19	Op.general	50Q5	Level 5 negative-sequence instantaneous overcurrent element
QPIOC23	Op.general	50Q6	Level 6 negative-sequence instantaneous overcurrent element
QPIOC3	Op.general	50Q1	Level 1 negative-sequence instantaneous overcurrent element
QPIOC7	Op.general	50Q2	Level 2 negative-sequence instantaneous overcurrent element
QRPIOC45	Op.general	50QR	Reverse direction negative-sequence overcurrent threshold exceeded
QRRDIR2	Dir.dirGeneral	32QR?0:2	If direction is reverse, value is 2, otherwise 0
QRRDIR2	Dir.general	32QR	Reverse directional control for negative-sequence overcurrent elements
SAGPTUV22	Op.general	SAG3P	Three-phase voltage SAG element
SAGPTUV22	Op.phsA	SAGA	A-phase voltage SAG element
SAGPTUV22	Op.phsB	SAGB	B-phase voltage SAG element
SAGPTUV22	Op.phsC	SAGC	C-phase voltage SAG element
SAGPTUV22	Str.general	SAG3P	Three-phase voltage SAG element
SWLPTOV29	Op.general	SW3P	Three-phase voltage swell element
SWLPTOV29	Op.phsA	SWA	A-phase voltage swell element
SWLPTOV29	Op.phsB	SWB	B-phase voltage swell element
SWLPTOV29	Op.phsC	SWC	C-phase voltage swell element

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Table L.19   Logical Device: PRO (Protection) (Sheet 6 of 7)

Logical Node	Attribute	Data Source	Comment
SWLPTOV29	Str.general	SW3P	Three-phase voltage swell element
TRIPPTRC1	Tr.general	TRIP3P	Three-phase trip logic output asserted
TRIPPTRC1	Tr.phsA	TRIPA	A-Phase trip logic output asserted
TRIPPTRC1	Tr.phsB	TRIPB	B-Phase trip logic output asserted
TRIPPTRC1	Tr.phsC	TRIPC	C-Phase trip logic output asserted
YABPTOV7	Str.general	59YAB1	AB-phase-to-phase overvoltage element, Y-terminal
YABPTUV8	Op.general	27YAB1	AB-phase-to-phase undervoltage element, Y-terminal
YABPTUV8	Str.general	27YAB1	AB-phase-to-phase undervoltage element, Y-terminal
YAPTOV1	Str.general	59YA1	#1 A-phase overvoltage element, Y-terminal
YAPTOV4	Str.general	59YA2	#2 A-phase overvoltage element, Y-terminal
YAPTUV2	Op.general	27YA1	#1 A-phase undervoltage element, Y-terminal
YAPTUV2	Str.general	27YA1	#1 A-phase undervoltage element, Y-terminal
YAPTUV5	Op.general	27YA2	#2 A-phase undervoltage element, Y-terminal
YAPTUV5	Str.general	27YA2	#2 A-phase undervoltage element, Y-terminal
YBCPTOV8	Str.general	59YBC1	BC-phase-to-phase overvoltage element, Y-terminal
YBCPTUV9	Op.general	27YBC1	BC-phase-to-phase undervoltage element, Y-terminal
YBCPTUV9	Str.general	27YBC1	BC-phase-to-phase undervoltage element, Y-terminal
YBPTOV2	Str.general	59YB1	#1 B-phase overvoltage element, Y-terminal
YBPTOV5	Str.general	59YB2	#2 B-phase overvoltage element, Y-terminal
YBPTUV3	Op.general	27YB1	#1 B-phase undervoltage element, Y-terminal
YBPTUV3	Str.general	27YB1	#1 B-phase undervoltage element, Y-terminal
YBPTUV6	Op.general	27YB2	#2 B-phase undervoltage element, Y-terminal
YBPTUV6	Str.general	27YB2	#2 B-phase undervoltage element, Y-terminal
YCAPTOV9	Str.general	59YCA1	CA-phase-to-phase overvoltage element, Y-terminal
YCAPTUV10	Op.general	27YCA1	CA-phase-to-phase undervoltage element, Y-terminal
YCAPTUV10	Str.general	27YCA1	CA-phase-to-phase undervoltage element, Y-terminal
YCPTOV3	Str.general	59YC1	#1 C-phase overvoltage element, Y-terminal
YCPTOV6	Str.general	59YC2	#2 C-phase overvoltage element, Y-terminal
YCPTUV4	Op.general	27YC1	#1 C-phase undervoltage element, Y-terminal
YCPTUV4	Str.general	27YC1	#1 C-phase undervoltage element, Y-terminal
YCPTUV7	Op.general	27YC2	#2 C-phase undervoltage element, Y-terminal
YCPTUV7	Str.general	27YC2	#2 C-phase undervoltage element, Y-terminal
YNPTOV12	Str.general	59YN1	#1 Zero-sequence overvoltage element, Y-terminal
YNPTOV13	Str.general	59YN2	#2 Zero-sequence overvoltage element, Y-terminal
YQPTOV11	Str.general	59YQ1	Negative-sequence overvoltage element, Y-terminal
YVPTOV14	Str.general	59YV1	Positive-sequence overvoltage element, Y-terminal
ZABPTOV21	Str.general	59ZAB1	AB-phase-to-phase overvoltage element, Z-terminal
ZABPTUV18	Op.general	27ZAB1	AB-phase-to-phase undervoltage element, Z-terminal
ZABPTUV18	Str.general	27ZAB1	AB-phase-to-phase undervoltage element, Z-terminal
ZAPTOV15	Str.general	59ZA1	A-phase overvoltage element, Z-terminal
ZAPTOV18	Str.general	59ZA2	A-phase overvoltage element, Z-terminal

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Table L.19 Logical Device: PRO (Protection) (Sheet 7 of 7)

Logical Node	Attribute	Data Source	Comment
ZAPTUV12	Op.general	27ZA1	#1 A-phase undervoltage element, Z-terminal
ZAPTUV12	Str.general	27ZA1	#1 A-phase undervoltage element, Z-terminal
ZAPTUV15	Op.general	27ZA2	#2 A-phase undervoltage element, Z-terminal
ZAPTUV15	Str.general	27ZA2	#2 A-phase undervoltage element, Z-terminal
ZBCPTOV22	Str.general	59ZBC1	BC-phase-to-phase overvoltage element, Z-terminal
ZBCPTUV19	Op.general	27ZBC1	BC-phase-to-phase undervoltage element, Z-terminal
ZBCPTUV19	Str.general	27ZBC1	BC-phase-to-phase undervoltage element, Z-terminal
ZBPTOV16	Str.general	59ZB1	B-phase overvoltage element, Z-terminal
ZBPTOV19	Str.general	59ZB2	B-phase overvoltage element, Z-terminal
ZBPTUV13	Op.general	27ZB1	#1 B-phase undervoltage element, Z-terminal
ZBPTUV13	Str.general	27ZB1	#1 B-phase undervoltage element, Z-terminal
ZBPTUV16	Op.general	27ZB2	#2 B-phase undervoltage element, Z-terminal
ZBPTUV16	Str.general	27ZB2	#2 B-phase undervoltage element, Z-terminal
ZCAPTOV23	Str.general	59ZCA1	CA-phase-to-phase overvoltage element, Z-terminal
ZCAPTUV20	Op.general	27ZCA1	CA-phase-to-phase undervoltage element, Z-terminal
ZCAPTUV20	Str.general	27ZCA1	CA-phase-to-phase undervoltage element, Z-terminal
ZCPTOV17	Str.general	59ZC1	C-phase overvoltage element, Z-terminal
ZCPTOV20	Str.general	59ZC2	C-phase overvoltage element, Z-terminal
ZCPTUV14	Op.general	27ZC1	#1 C-phase undervoltage element, Z-terminal
ZCPTUV14	Str.general	27ZC1	#1 C-phase undervoltage element, Z-terminal
ZCPTUV17	Op.general	27ZC2	#2 C-phase undervoltage element, Z-terminal
ZCPTUV17	Str.general	27ZC2	#2 C-phase undervoltage element, Z-terminal
ZNPTOV26	Str.general	59ZN1	Zero-sequence overvoltage element, Z-terminal
ZNPTOV27	Str.general	59ZN2	Zero-sequence overvoltage element, Z-terminal
ZQPTOV25	Str.general	59ZQ1	Negative-sequence overvoltage element, Z-terminal
ZVPTOV28	Str.general	59ZV1	Positive-sequence overvoltage elements, Z-terminal

a Writing a 0 to BCCSWI1COPos$Oper$ctlVal, BCACSWI2COPos$Oper$ctlVal, BCBCSWI3COPos$Oper$ctlVal, or BCCCSWI4COPos$Oper$ctlVal will cause OCn to assert, and writing any other value will cause CCn to assert (where n = 3, A, B, or C, respectively).

b If breaker is closed, value = 1O (2). If breaker is opened, value = O1 (1).

Table L.20 shows the LNs associated with measuring elements, defined as Logical Device MET. See *Appendix F: Relay Word Bits* and *Appendix G: Analog Quantities* for descriptions.

Table L.20 Logical Device: MET (Measurement) (Sheet 1 of 4)

Logical Node	Attribute	Data Source	Comment
Functional Constraint = MXa			
DCZBAT1	Vol.instMag.f	VBAT	Battery voltage level
METMDST1	DmdA.neut.instMag.f	INDEM	Demand, neutral current
METMDST1	DmdA.nseq.instMag.f	3I2DEM	Demand, negative-sequence current
METMDST1	DmdA.phsA.instMag.f	IADEM	Demand, phase A current
METMDST1	DmdA.phsB.instMag.f	IBDEM	Demand, phase B current
METMDST1	DmdA.phsC.instMag.f	ICDEM	Demand, phase C current

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Table L.20   Logical Device: MET (Measurement) (Sheet 2 of 4)

Logical Node	Attribute	Data Source	Comment
METMDST1	DmdA.res.instMag.f	IGDEM	Demand, residual current
METMDST1	DmdVArh.instMag.f	MVRH3O	Energy, reactive (MVARh), supply direction away from
METMDST1	DmdWh.instMag.f	MWH3O	Energy, real (MWh), supply direction away from
METMDST1	PkDmdA.neut.instMag.f	INPK	Peak demand, neutral current
METMDST1	PkDmdA.nseq.instMag.f	3I2PK	Peak demand, negative-sequence current
METMDST1	PkDmdA.phsA.instMag.f	IAPK	Peak demand, phase A current
METMDST1	PkDmdA.phsB.instMag.f	IBPK	Peak demand, phase B current
METMDST1	PkDmdA.phsC.instMag.f	ICPK	Peak demand, phase C current
METMDST1	PkDmdA.res.instMag.f	IGPK	Peak demand, residual current
METMDST1	SupVArh.instMag.f	MVRH3I	Energy, reactive (MVARh), supply direction toward busbar
METMDST1	SupWh.instMag.f	MWH3I	Energy, real (MWh), supply direction toward busbar
METMMXU1	TotW.instMag.f	KW3	Three-phase real power
METMMXU1	TotVAr.instMag.f	KVAR3	Three-phase reactive power
METMMXU1	TotVA.instMag.f	KVA3	Three-phase apparent power
METMMXU1	TotPF.instMag.f	PF3	Three-phase power factor
METMMXU1	A.phsA.instCVal.mag.f	IA	A-phase current magnitude
METMMXU1	A.phsA.instCVal.ang.f	IAFA	A-phase current angle
METMMXU1	A.phsB.instCVal.mag.f	IB	B-phase current magnitude
METMMXU1	A.phsB.instCVal.ang.f	IBFA	B-phase current angle
METMMXU1	A.phsC.instCVal.mag.f	IC	C-phase current magnitude
METMMXU1	A.phsC.instCVal.ang.f	ICFA	C-phase current angle
METMMXU1	A.res.instCVal.mag.f	IG	Residual current magnitude
METMMXU1	A.res.instCVal.ang.f	IGFA	Residual current angle
METMMXU1	A.neut.instCVal.mag.f	IN	Neutral current magnitude
METMMXU1	A.neut.instCVal.ang.f	INFA	Neutral current angle
METMMXU1	Hz.instMag.f	FREQ	Measured frequency
METMMXU1	PF.phsA.instCVal.mag.f	PFA	A-phase power factor
METMMXU1	PF.phsB.instCVal.mag.f	PFB	B-phase power factor
METMMXU1	PF.phsC.instCVal.mag.f	PFC	C-phase power factor
METMMXU1	PhV1.phsA.instCVal.mag.f	VAY	A-phase voltage magnitude, Y-terminals
METMMXU1	PhV1.phsA.instCVal.ang.f	VAYFA	A-phase voltage angle, Y-terminals
METMMXU1	PhV1.phsB.instCVal.mag.f	VBY	B-phase voltage magnitude, Y-terminals
METMMXU1	PhV1.phsB.instCVal.ang.f	VBYFA	B-phase voltage angle, Y-terminals
METMMXU1	PhV1.phsC.instCVal.mag.f	VCY	C-phase voltage magnitude, Y-terminals
METMMXU1	PhV1.phsC.instCVal.ang.f	VCYFA	C-phase voltage angle, Y-terminals
METMMXU1	PhV2.phsA.instCVal.mag.f	VAZ	A-phase voltage magnitude, Z-terminals
METMMXU1	PhV2.phsA.instCVal.ang.f	VAZFA	A-phase voltage angle, Z-terminals
METMMXU1	PhV2.phsB.instCVal.mag.f	VBZ	B-phase voltage magnitude, Z-terminals
METMMXU1	PhV2.phsB.instCVal.ang.f	VBZFA	B-phase voltage angle, Z-terminals
METMMXU1	PhV2.phsC.instCVal.mag.f	VCZ	C-phase voltage magnitude, Z-terminals
METMMXU1	PhV2.phsC.instCVal.ang.f	VCZFA	C-phase voltage angle, Z-terminals

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Table L.20   Logical Device: MET (Measurement) (Sheet 3 of 4)

Logical Node	Attribute	Data Source	Comment
METMMXU1	PPV1.phsAB.instCVal.mag.f	VABY	AB phase-phase voltage magnitude, Y-terminals
METMMXU1	PPV1.phsAB.instCVal.ang.f	VABYFA	AB phase-phase voltage angle, Y-terminals
METMMXU1	PPV1.phsBC.instCVal.mag.f	VBCY	BC phase-phase voltage magnitude, Y-terminals
METMMXU1	PPV1.phsBC.instCVal.ang.f	VBCYFA	BC phase-phase voltage angle, Y-terminals
METMMXU1	PPV1.phsCA.instCVal.mag.f	VCAY	CA phase-phase voltage magnitude, Y-terminals
METMMXU1	PPV1.phsCA.instCVal.ang.f	VCAYFA	CA phase-phase voltage angle, Y-terminals
METMMXU1	PPV2.phsAB.instCVal.mag.f	VABZ	AB phase-phase voltage magnitude, Z-terminals
METMMXU1	PPV2.phsAB.instCVal.ang.f	VABZFA	AB phase-phase voltage angle, Z-terminals
METMMXU1	PPV2.phsBC.instCVal.mag.f	VBCZ	BC phase-phase voltage magnitude, Z-terminals
METMMXU1	PPV2.phsBC.instCVal.ang.f	VBCZFA	BC phase-phase voltage angle, Z-terminals
METMMXU1	PPV2.phsCA.instCVal.mag.f	VCAZ	CA phase-phase voltage magnitude, Z-terminals
METMMXU1	PPV2.phsCA.instCVal.ang.f	VCAZFA	CA phase-phase voltage angle, Z-terminals
METMMXU1	W.phsA.instCVal.mag.f	KWA	A-phase real power
METMMXU1	W.phsB.instCVal.mag.f	KWB	B-phase real power
METMMXU1	W.phsC.instCVal.mag.f	KWC	C-phase real power
METMMXU1	VA.phsA.instCVal.mag.f	KVAA	A-phase apparent power
METMMXU1	VA.phsB.instCVal.mag.f	KVAB	B-phase apparent power
METMMXU1	VA.phsC.instCVal.mag.f	KVAC	C-phase apparent power
METMMXU1	VAr.phsA.instCVal.mag.f	KVARA	A-phase reactive power
METMMXU1	VAr.phsB.instCVal.mag.f	KVARB	B-phase reactive power
METMMXU1	VAr.phsC.instCVal.mag.f	KVARC	C-phase reactive power
METMSQI1	SeqA.c1.instCVal.mag.f	I1	Positive-sequence current magnitude
METMSQI1	SeqA.c1.instCVal.ang.f	I1FA	Positive-sequence current angle
METMSQI1	SeqA.c2.instCVal.mag.f	3I2	Negative-sequence current magnitude
METMSQI1	SeqA.c2.instCVal.ang.f	3I2FA	Negative-sequence current angle
METMSQI1	SeqA.c3.instCVal.mag.f	3I0	Zero-sequence current magnitude
METMSQI1	SeqA.c3.instCVal.ang.f	3I0FA	Zero-sequence current angle
METMSQI1	SeqV1.c1.instCVal.mag.f	V1Y	Positive-sequence voltage magnitude, Y-terminals
METMSQI1	SeqV1.c1.instCVal.ang.f	V1YFA	Positive-sequence voltage angle, Y-terminals
METMSQI1	SeqV1.c2.instCVal.mag.f	V2Y	Negative-sequence voltage magnitude, Y-terminals
METMSQI1	SeqV1.c2.instCVal.ang.f	V2YFA	Negative-sequence voltage angle, Y-terminals
METMSQI1	SeqV1.c3.instCVal.mag.f	3V0Y	Zero-sequence voltage magnitude, Y-terminals
METMSQI1	SeqV1.c3.instCVal.ang.f	3V0YFA	Zero-sequence voltage angle, Y-terminals
METMSQI1	SeqV2.c1.instCVal.mag.f	V1Z	Positive-sequence voltage magnitude, Z-terminals
METMSQI1	SeqV2.c1.instCVal.ang.f	V1ZFA	Positive-sequence voltage angle, Z-terminals
METMSQI1	SeqV2.c2.instCVal.mag.f	V2Z	Negative-sequence voltage magnitude, Z-terminals
METMSQI1	SeqV2.c2.instCVal.ang.f	V2ZFA	Negative-sequence voltage angle, Z-terminals
METMSQI1	SeqV2.c3.instCVal.mag.f	3V0Z	Zero-sequence voltage magnitude, Z-terminals
METMSQI1	SeqV2.c3.instCVal.ang.f	3V0ZFA	Zero-sequence voltage angle, Z-terminals
METMSTA1	MaxA.phsA.instMag.f	IAMAX[b]	A-phase current, maximum magnitude
METMSTA1	MaxA.phsB.instMag.f	IBMAX[b]	B-phase current, maximum magnitude

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Table L.20   Logical Device: MET (Measurement) (Sheet 4 of 4)

Logical Node	Attribute	Data Source	Comment
METMSTA1	MaxA.phsC.instMag.f	ICMAX[b]	C-phase current, maximum magnitude
METMSTA1	MaxA.neut.instMag.f	INMAX[b]	Neutral current, maximum magnitude
METMSTA1	MaxA.res.instMag.f	IGMAX[b]	Residual current, maximum magnitude
METMSTA1	MinA.phsA.instMag.f	IAMIN[b]	A-phase current, minimum magnitude
METMSTA1	MinA.phsB.instMag.f	IBMIN[b]	B-phase current, minimum magnitude
METMSTA1	MinA.phsC.instMag.f	ICMIN[b]	C-phase current, minimum magnitude
METMSTA1	MinA.neut.instMag.f	INMIN[b]	Neutral current, minimum magnitude
METMSTA1	MinA.res.instMag.f	IGMIN[b]	Residual current, minimum magnitude
METMSTA1	MaxPhV1.phsA.instMag.f	VAYMAX[b]	A-phase-to-neutral, voltage, Y-terminals, maximum magnitude
METMSTA1	MaxPhV1.phsB.instMag.f	VBYMAX[b]	B-phase-to-neutral, voltage, Y-terminals, maximum magnitude
METMSTA1	MaxPhV1.phsC.instMag.f	VCYMAX[b]	C-phase-to-neutral, voltage, Y-terminals, maximum magnitude
METMSTA1	MaxPhV2.phsA.instMag.f	VAZMAX[b]	A-phase-to-neutral, voltage, Z-terminals, maximum magnitude
METMSTA1	MaxPhV2.phsB.instMag.f	VBZMAX[b]	B-phase-to-neutral, voltage, Z-terminals, maximum magnitude
METMSTA1	MaxPhV2.phsC.instMag.f	VCZMAX[b]	C-phase-to-neutral, voltage, Z-terminals, maximum magnitude
METMSTA1	MinPhV1.phsA.instMag.f	VAYMIN[b]	A-phase-to-neutral, voltage, Y-terminals, minimum magnitude
METMSTA1	MinPhV1.phsB.instMag.f	VBYMIN[b]	B-phase-to-neutral, voltage, Y-terminals, minimum magnitude
METMSTA1	MinPhV1.phsC.instMag.f	VCYMIN[b]	C-phase-to-neutral, voltage, Y-terminals, minimum magnitude
METMSTA1	MinPhV2.phsA.instMag.f	VAZMIN[b]	A-phase-to-neutral, voltage, Z-terminals, minimum magnitude
METMSTA1	MinPhV2.phsB.instMag.f	VBZMIN[b]	B-phase-to-neutral, voltage, Z-terminals, minimum magnitude
METMSTA1	MinPhV2.phsC.instMag.f	VCZMIN[b]	C-phase-to-neutral, voltage, Z-terminals, minimum magnitude
METMSTA1	MaxVA.instMag.f	MVA3MAX[b]	Three-phase apparent power, maximum magnitude
METMSTA1	MinVA.instMag.f	MVA3MIN[b]	Three-phase apparent power, minimum magnitude
METMSTA1	AvW.instMag.f	MW3R	Three-phase average real power magnitude
METMSTA1	AvPhW.phsA.instCVal.mag.f	MWAR	A-phase average real power magnitude
METMSTA1	AvPhW.phsB.instCVal.mag.f	MWBR	B-phase average real power magnitude
METMSTA1	AvPhW.phsC.instCVal.mag.f	MWCR	C-phase average real power magnitude
METMSTA1	MaxW.instMag.f	MW3MAX[b]	Three-phase real power, maximum magnitude
METMSTA1	MinW.instMag.f	MW3MIN[b]	Three-phase real power, minimum magnitude
METMSTA1	MaxVAr.instMag.f	MVR3MAX[b]	Three-phase reactive power, maximum magnitude
METMSTA1	MinVAr.instMag.f	MVR3MIN[b]	Three-phase reactive power, minimum magnitude

[a] MX values contain instantaneous attributes (instMag and instCVal), which are updated whenever the source updates and other attributes that are only updated when the source goes outside the points dead band (mag and cVal). Only the instantaneous values are shown in the table.

[b] Minimum values that have been reset report the largest positive value possible.
Maximum values that have been reset report the largest negative value possible.

Table L.21 shows the LNs associated with control elements, defined as Logical Device CON. See *Appendix F: Relay Word Bits* for descriptions.

Table L.21   Logical Device: CON (Remote Control) (Sheet 1 of 2)

Logical Node	Status	Control	Relay Word Bit	Comment
RBGGIO1	SPCSO01.stVal–SPCSO08.stVal	SPCSO01.Oper.ctlVal–SPCSO08.Oper.ctlVal	RB01–RB08	Remote Bits (RB01–RB08)
RBGGIO2	SPCSO09.stVal–SPCSO16.stVal	SPCSO09.Oper.ctlVal–SPCSO16.Oper.ctlVal	RB09–RB16	Remote Bits (RB09–RB16)

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Table L.21 Logical Device: CON (Remote Control) (Sheet 2 of 2)

Logical Node	Status	Control	Relay Word Bit	Comment
RBGGIO3	SPCSO17.stVal–SPC-SO24.stVal	SPCSO17.Oper.ctlVal–SPC-SO24.Oper.ctlVal	RB17–RB24	Remote Bits (RB17–RB24)
RBGGIO4	SPCSO25.stVal–SPC-SO32.stVal	SPCSO25.Oper.ctlVal–SPC-SO32.Oper.ctlVal	RB25–RB32	Remote Bits (RB25–RB32)

Table L.22 shows the LNs associated with the annunciation element, defined as Logical Device ANN. See *Appendix F: Relay Word Bits* and *Appendix G: Analog Quantities* for descriptions.

Table L.22 Logical Device: ANN (Annunciation) (Sheet 1 of 5)

Logical Node	Attribute	Data Source	Comment
Functional Constraint = ST			
ALMGGIO8	Ind01.stVal	HALARM	Indication of a diagnostic failure or warning that warrants an ALARM
ALMGGIO8	Ind02.stVal	HALARML	Latches in for relay diagnostic failures
ALMGGIO8	Ind03.stVal	HALARMP	Pulses for five seconds when a warning diagnostic condition occurs
ALMGGIO8	Ind04.stVal	HALARMA	Pulses for five seconds per minute until reset when a hardware diagnostic warning occurs
ALMGGIO8	Ind07.stVal	ACCESS	Asserted while any user is logged in at Access Level B or higher
ALMGGIO8	Ind08.stVal	SALARM	Indication of software or user activity that warrants an ALARM
ALMGGIO8	Ind09.stVal	BADPASS	Pulses for approximately one second whenever a user enters three successive bad passwords in an SEL ASCII terminal session or web session
ALMGGIO8	Ind10.stVal	CHGPASS	Pulses for approximately one second whenever a password changes
ALMGGIO8	Ind11.stVal	SETCHG	Pulses for approximately one second whenever settings are changed
ALMGGIO8	Ind13.stVal	ACCESSP	Pulses for approximately one second when any user increases their access level to B or higher
ALMGGIO8	Ind14.stVal	PASNVAL	Pulses for approximately one second when an incorrect password is entered when attempting to enter Access Level B or higher, or when changing passwords
BATGGIO24	Ind01.stVal	CHRGG	Battery is charging
BATGGIO24	Ind02.stVal	DISCHG	Battery is discharging
BATGGIO24	Ind03.stVal	DTFAIL	Battery failed discharge test
BATGGIO24	Ind04.stVal	BTFAIL	Battery failure
BATGGIO24	Ind05.stVal	TOSLP	To Sleep—asserts for last minute of control operation on battery power
BATGGIO24	Ind06.stVal	PWR_SRC1	Recloser control power supply is operating from external power source
BATGGIO24	Ind07.stVal	TCCAP	Recloser interface trip and close capacitor fully charged
BATGGIO24	Ind08.stVal	DISTST	Asserted when battery discharge test is in progress
BKGGIO26	Ind01.stVal	52AA	A-phase breaker status
BKGGIO26	Ind02.stVal	52AB	B-phase breaker status
BKGGIO26	Ind03.stVal	52AC	C-phase breaker status
BKGGIO26	Ind04.stVal	52A3P	Three-phase breaker status
BKGGIO26	Ind05.stVal	SPOA	A-phase single pole open

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Table L.22   Logical Device: ANN (Annunciation) (Sheet 2 of 5)

Logical Node	Attribute	Data Source	Comment
BKGGIO26	Ind06.stVal	SPOB	B-phase single pole open
BKGGIO26	Ind07.stVal	SPOC	C-phase single pole open
BKGGIO26	Ind08.stVal	SPO	Any phase single pole open
BKGGIO26	Ind09.stVal	3PO	Three-phase pole open
ETHGGIO23	Ind01.stVal	P5ASEL	Asserted when Port 5A is active
ETHGGIO23	Ind02.stVal	LINK5A	Asserted when a valid link is detected on Port 5A
ETHGGIO23	Ind03.stVal	P5BSEL	Asserted when Port 5B is active
ETHGGIO23	Ind04.stVal	LINK5B	Asserted when a valid link is detected on Port 5B
ETHGGIO23	Ind05.stVal	LNKFAIL	Asserted when a valid link is not detected on the active port(s)
H2BLKGGIO27	Ind03.stVal	HBL2AT	A-phase second-harmonic element timed out
H2BLKGGIO27	Ind02.stVal	HBL2BT	B-phase second-harmonic element timed out
H2BLKGGIO27	Ind01.stVal	HBL2CT	C-Phase second-harmonic element timed out
H2BLKGGIO27	Ind04.stVal	HBL2T	One or more phase second-harmonic elements timed out
IN1GGIO1	Ind01.stVal	IN101	Optoisolated input IN101 asserted
IN1GGIO1	Ind02.stVal	IN102	Optoisolated input IN102 asserted
IN1GGIO1	Ind03.stVal	IN103	Optoisolated input IN103 asserted
IN1GGIO1	Ind04.stVal	IN104	Optoisolated input IN104 asserted
IN1GGIO1	Ind05.stVal	IN105	Optoisolated input IN105 asserted
IN1GGIO1	Ind06.stVal	IN106	Optoisolated input IN106 asserted
IN1GGIO1	Ind07.stVal	IN107	Optoisolated input IN107 asserted
IN2GGIO2	Ind01.stVal	IN201	Optoisolated input IN201 asserted
IN2GGIO2	Ind02.stVal	IN202	Optoisolated input IN202 asserted
IN2GGIO2	Ind03.stVal	IN203	Optoisolated input IN203 asserted
IN2GGIO2	Ind04.stVal	IN204	Optoisolated input IN204 asserted
IN2GGIO2	Ind05.stVal	IN205	Optoisolated input IN205 asserted
IN2GGIO2	Ind06.stVal	IN206	Optoisolated input IN206 asserted
LBGGIO17	Ind01.stVal	LB01	Local Bit 1 asserted
LBGGIO17	Ind02.stVal–Ind32.stVal	LB02–LB32	Local Bit 2–32 asserted
MBOKGGIO13	Ind01.stVal	ROKA	Received MIRRORED BITS data OK, Channel A
MBOKGGIO13	Ind02.stVal	RBADA	MIRRORED BITS channel A outage duration over threshold
MBOKGGIO13	Ind03.stVal	CBADA	MIRRORED BITS channel A unavailability over threshold
MBOKGGIO13	Ind04.stVal	LBOKA	Loop back MIRRORED BITS data OK, Channel A
MBOKGGIO13	Ind05.stVal	ROKB	Received MIRRORED BITS data OK, Channel B
MBOKGGIO13	Ind06.stVal	RBADB	MIRRORED BITS channel B outage duration over threshold
MBOKGGIO13	Ind07.stVal	CBADB	MIRRORED BITS channel B unavailability over threshold
MBOKGGIO13	Ind08.stVal	LBOKB	Loop back MIRRORED BITS data OK, Channel B
MVGGIO28	AnIn01.instMag.f	MV01	Math variable 1
MVGGIO28	AnIn02.instMag.f–AnIn64.instMag.f	MV02–MV64	Math variable 2–64
OUT1GGIO3	Ind01.stVal	OUT101	Output contact OUT101 asserted
OUT1GGIO3	Ind02.stVal	OUT102	Output contact OUT102 asserted

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Table L.22   Logical Device: ANN (Annunciation) (Sheet 3 of 5)

Logical Node	Attribute	Data Source	Comment
OUT1GGIO3	Ind03.stVal	OUT103	Output contact OUT103 asserted
OUT1GGIO3	Ind04.stVal	OUT104	Output contact OUT104 asserted
OUT1GGIO3	Ind05.stVal	OUT105	Output contact OUT105 asserted
OUT1GGIO3	Ind06.stVal	OUT106	Output contact OUT106 asserted
OUT1GGIO3	Ind07.stVal	OUT107	Output contact OUT107 asserted
OUT1GGIO3	Ind08.stVal	OUT108	Output contact OUT108 asserted
OUT2GGIO4	Ind01.stVal	OUT201	Output contact OUT201 asserted
OUT2GGIO4	Ind02.stVal	OUT202	Output contact OUT202 asserted
PBGGIO22	Ind01.stVal	PB01_LED	Operator control pushbutton LED 1
PBGGIO22	Ind02.stVal	PB02_LED	Operator control pushbutton LED 2
PBGGIO22	Ind03.stVal	PB03_LED	Operator control pushbutton LED 3
PBGGIO22	Ind04.stVal	PB04_LED	Operator control pushbutton LED 4
PBGGIO22	Ind05.stVal	PB05_LED	Operator control pushbutton LED 5
PBGGIO22	Ind06.stVal	PB06_LED	Operator control pushbutton LED 6
PBGGIO22	Ind07.stVal	PB07_LED	Operator control pushbutton LED 7
PBGGIO22	Ind08.stVal	PB08_LED	Operator control pushbutton LED 8
PBGGIO22	Ind09.stVal	PB09_LED	Operator control pushbutton LED 9
PBGGIO22	Ind10.stVal	PB10_LED	Operator control pushbutton LED 10
PBGGIO22	Ind11.stVal	PB11_LED	Operator control pushbutton LED 11
PBGGIO22	Ind12.stVal	PB12_LED	Operator control pushbutton LED 12
RC3GGIO18	Ind01.stVal	79RS3P	Reclosing relay in the Reset State
RC3GGIO18	Ind02.stVal	79CY3P	Reclosing relay in the Reclose Cycle State
RC3GGIO18	Ind03.stVal	79LO3P	Reclosing relay in the Lockout State
RC3GGIO18	Ind04.stVal	SH03P	Reclosing relay shot counter = 0
RC3GGIO18	Ind05.stVal	SH13P	Reclosing relay shot counter = 1
RC3GGIO18	Ind06.stVal	SH23P	Reclosing relay shot counter = 2
RC3GGIO18	Ind07.stVal	SH33P	Reclosing relay shot counter = 3
RC3GGIO18	Ind08.stVal	SH43P	Reclosing relay shot counter = 4
RCAGGIO19	Ind01.stVal	79RSA	A-phase reclosing relay in the Reset State
RCAGGIO19	Ind02.stVal	79CYA	A-phase reclosing relay in the Reclose Cycle State
RCAGGIO19	Ind03.stVal	79LOA	A-phase reclosing relay in the Lockout State
RCAGGIO19	Ind04.stVal	SH0A	A-phase reclosing relay shot counter = 0
RCAGGIO19	Ind05.stVal	SH1A	A-phase reclosing relay shot counter = 1
RCAGGIO19	Ind06.stVal	SH2A	A-phase reclosing relay shot counter = 2
RCAGGIO19	Ind07.stVal	SH3A	A-phase reclosing relay shot counter = 3
RCAGGIO19	Ind08.stVal	SH4A	A-phase reclosing relay shot counter = 4
RCBGGIO20	Ind01.stVal	79RSB	B-phase reclosing relay in the Reset State
RCBGGIO20	Ind02.stVal	79CYB	B-phase reclosing relay in the Reclose Cycle State
RCBGGIO20	Ind03.stVal	79LOB	B-phase reclosing relay in the Lockout State
RCBGGIO20	Ind04.stVal	SH0B	B-phase reclosing relay shot counter = 0
RCBGGIO20	Ind05.stVal	SH1B	B-phase reclosing relay shot counter = 1

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Table L.22   Logical Device: ANN (Annunciation) (Sheet 4 of 5)

Logical Node	Attribute	Data Source	Comment
RCBGGIO20	Ind06.stVal	SH2B	B-phase reclosing relay shot counter = 2
RCBGGIO20	Ind07.stVal	SH3B	B-phase reclosing relay shot counter = 3
RCBGGIO20	Ind08.stVal	SH4B	B-phase reclosing relay shot counter = 4
RCCGGIO21	Ind01.stVal	79RSC	C-phase reclosing relay in the Reset State
RCCGGIO21	Ind02.stVal	79CYC	C-phase reclosing relay in the Reclose Cycle State
RCCGGIO21	Ind03.stVal	79LOC	C-phase reclosing relay in the Lockout State
RCCGGIO21	Ind04.stVal	SH0C	C-phase reclosing relay shot counter = 0
RCCGGIO21	Ind05.stVal	SH1C	C-phase reclosing relay shot counter = 1
RCCGGIO21	Ind06.stVal	SH2C	C-phase reclosing relay shot counter = 2
RCCGGIO21	Ind07.stVal	SH3C	C-phase reclosing relay shot counter = 3
RCCGGIO21	Ind08.stVal	SH4C	C-phase reclosing relay shot counter = 4
RMBAGGIO9	Ind01.stVal	RMB1A	Channel A received MIRRORED BIT 1
RMBAGGIO9	Ind02.stVal	RMB2A	Channel A received MIRRORED BIT 2
RMBAGGIO9	Ind03.stVal	RMB3A	Channel A received MIRRORED BIT 3
RMBAGGIO9	Ind04.stVal	RMB4A	Channel A received MIRRORED BIT 4
RMBAGGIO9	Ind05.stVal	RMB5A	Channel A received MIRRORED BIT 5
RMBAGGIO9	Ind06.stVal	RMB6A	Channel A received MIRRORED BIT 6
RMBAGGIO9	Ind07.stVal	RMB7A	Channel A received MIRRORED BIT 7
RMBAGGIO9	Ind08.stVal	RMB8A	Channel A received MIRRORED BIT 8
RMBBGGIO11	Ind01.stVal	RMB1B	Channel B received MIRRORED BIT 1
RMBBGGIO11	Ind02.stVal	RMB2B	Channel B received MIRRORED BIT 2
RMBBGGIO11	Ind03.stVal	RMB3B	Channel B received MIRRORED BIT 3
RMBBGGIO11	Ind04.stVal	RMB4B	Channel B received MIRRORED BIT 4
RMBBGGIO11	Ind05.stVal	RMB5B	Channel B received MIRRORED BIT 5
RMBBGGIO11	Ind06.stVal	RMB6B	Channel B received MIRRORED BIT 6
RMBBGGIO11	Ind07.stVal	RMB7B	Channel B received MIRRORED BIT 7
RMBBGGIO11	Ind08.stVal	RMB8B	Channel B received MIRRORED BIT 8
SCGGIO25	IntIn01.stVal.instMag.f	SC01	SELOGIC counter 1
SCGGIO25	IntIn02.stVal.instMag.f	SC02	SELOGIC counter 2
SCGGIO25	IntIn03.stVal.instMag.f	SC03	SELOGIC counter 3
SCGGIO25	IntIn04.stVal.instMag.f	SC04	SELOGIC counter 4
SCGGIO25	IntIn05.stVal.instMag.f	SC05	SELOGIC counter 5
SCGGIO25	IntIn06.stVal.instMag.f	SC06	SELOGIC counter 6
SCGGIO25	IntIn07.stVal.instMag.f	SC07	SELOGIC counter 7
SCGGIO25	IntIn08.stVal.instMag.f	SC08	SELOGIC counter 8
SCGGIO25	IntIn09.stVal.instMag.f	SC09	SELOGIC counter 9
SCGGIO25	IntIn10.stVal.instMag.f	SC10	SELOGIC counter 10
SCGGIO25	IntIn11.stVal.instMag.f	SC11	SELOGIC counter 11
SCGGIO25	IntIn12.stVal.instMag.f	SC12	SELOGIC counter 12
SCGGIO25	IntIn13.stVal.instMag.f	SC13	SELOGIC counter 13
SCGGIO25	IntIn14.stVal.instMag.f	SC14	SELOGIC counter 14

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Table L.22   Logical Device: ANN (Annunciation) (Sheet 5 of 5)

Logical Node	Attribute	Data Source	Comment
SCGGIO25	IntIn15.stVal.instMag.f	SC15	SELOGIC counter 15
SCGGIO25	IntIn16.stVal.instMag.f	SC16	SELOGIC counter 16
SGGGIO16	Ind01.stVal	SG1	Setting group indication, group 1
SGGGIO16	Ind02.stVal	SG2	Setting group indication, group 2
SGGGIO16	Ind03.stVal	SG3	Setting group indication, group 3
SGGGIO16	Ind04.stVal	SG4	Setting group indication, group 4
SGGGIO16	Ind05.stVal	SG5	Setting group indication, group 5
SGGGIO16	Ind06.stVal	SG6	Setting group indication, group 6
SGGGIO16	Ind07.stVal	SG7	Setting group indication, group 7
SGGGIO16	Ind08.stVal	SG8	Setting group indication, group 8
SGGGIO16	Ind09.stVal	GRPSW	Group switch indication
SVGGIO5	Ind01.stVal	SV01	SELOGIC Variable 1
SVGGIO5	Ind02.stVal–Ind64.stVal	SV02–SV64	SELOGIC Variable 2–64
SVTGGIO6	Ind01.stVal	SV01T	SELOGIC Variable SV01 timer output asserted
SVTGGIO6	Ind02.stVal–Ind64.stVal	SV02T–SV64T	SELOGIC Variable SV02–64 timer output asserted
TLEDGGIO14	Ind01.stVal	TLED_01	Target LEDs 01
TLEDGGIO14	Ind02.stVal–Ind24.stVal	TLED_02–TLED_24	Target LEDs 02–24
TLEDGGIO14	Ind25.stVal	TRIPLED	Trip target LED
TLEDGGIO14	Ind26.stVal	EN	Enabled LED
TMBAGGIO10	Ind01.stVal	TMB1A	Channel A transmitted MIRRORED BIT 1
TMBAGGIO10	Ind02.stVal	TMB2A	Channel A transmitted MIRRORED BIT 2
TMBAGGIO10	Ind03.stVal	TMB3A	Channel A transmitted MIRRORED BIT 3
TMBAGGIO10	Ind04.stVal	TMB4A	Channel A transmitted MIRRORED BIT 4
TMBAGGIO10	Ind05.stVal	TMB5A	Channel A transmitted MIRRORED BIT 5
TMBAGGIO10	Ind06.stVal	TMB6A	Channel A transmitted MIRRORED BIT 6
TMBAGGIO10	Ind07.stVal	TMB7A	Channel A transmitted MIRRORED BIT 7
TMBAGGIO10	Ind08.stVal	TMB8A	Channel A transmitted MIRRORED BIT 8
TMBBGGIO12	Ind01.stVal	TMB1B	Channel B transmitted MIRRORED BIT 1
TMBBGGIO12	Ind02.stVal	TMB2B	Channel B transmitted MIRRORED BIT 2
TMBBGGIO12	Ind03.stVal	TMB3B	Channel B transmitted MIRRORED BIT 3
TMBBGGIO12	Ind04.stVal	TMB4B	Channel B transmitted MIRRORED BIT 4
TMBBGGIO12	Ind05.stVal	TMB5B	Channel B transmitted MIRRORED BIT 5
TMBBGGIO12	Ind06.stVal	TMB6B	Channel B transmitted MIRRORED BIT 6
TMBBGGIO12	Ind07.stVal	TMB7B	Channel B transmitted MIRRORED BIT 7
TMBBGGIO12	Ind08.stVal	TMB8B	Channel B transmitted MIRRORED BIT 8
VBGGIO15	Ind001.stVal	VB001[a]	Virtual Bit 001
VBGGIO15	Ind002.stVal–Ind128.stVal	VB002–VB128[a]	Virtual Bit 002–128

[a] Virtual bits retain state until overwritten or device is restarted.

Table L.23 shows the LNs associated with the configuration element, defined as Logical Device CFG.

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Table L.23   Logical Device: CFG (Configuration)

Logical Node	Attribute	Data Source	Comment
Functional Constraint = DC			
DevIDLPHD1	PhyNam.serNum	SERNUM	Relay serial number (string format)
LLN0	NamPlt.swRev	FID	Firmware revision

Table L.24 shows the LNs in alphabetical order of their corresponding Relay Word Bits to facilitate modification of the ICD file.

Table L.24   Logical Nodes by Data Source Names (Sheet 1 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
27B81	PRO	DPTOF1	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTOF2	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTOF3	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTOF4	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTOF5	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTOF6	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTUF1	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTUF2	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTUF3	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTUF4	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTUF5	BlkV.stVal	Undervoltage element for frequency element blocking
27B81	PRO	DPTUF6	BlkV.stVal	Undervoltage element for frequency element blocking
27YA1	PRO	YAPTUV2	Op.general	#1 A-phase undervoltage element, Y-terminal
27YA1	PRO	YAPTUV2	Str.general	#1 A-phase undervoltage element, Y-terminal
27YA2	PRO	YAPTUV5	Op.general	#2 A-phase undervoltage element, Y-terminal
27YA2	PRO	YAPTUV5	Str.general	#2 A-phase undervoltage element, Y-terminal
27YAB1	PRO	YABPTUV8	Op.general	AB-phase-to-phase undervoltage element, Y-terminal
27YAB1	PRO	YABPTUV8	Str.general	AB-phase-to-phase undervoltage element, Y-terminal
27YB1	PRO	YBPTUV3	Op.general	#1 B-phase undervoltage element, Y-terminal
27YB1	PRO	YBPTUV3	Str.general	#1 B-phase undervoltage element, Y-terminal
27YB2	PRO	YBPTUV6	Op.general	#2 B-phase undervoltage element, Y-terminal
27YB2	PRO	YBPTUV6	Str.general	#2 B-phase undervoltage element, Y-terminal
27YBC1	PRO	YBCPTUV9	Op.general	BC-phase-to-phase undervoltage element, Y-terminal
27YBC1	PRO	YBCPTUV9	Str.general	BC-phase-to-phase undervoltage element, Y-terminal
27YC1	PRO	YCPTUV4	Op.general	#1 C-phase undervoltage element, Y-terminal
27YC1	PRO	YCPTUV4	Str.general	#1 C-phase undervoltage element, Y-terminal
27YC2	PRO	YCPTUV7	Op.general	#2 C-phase undervoltage element, Y-terminal
27YC2	PRO	YCPTUV7	Str.general	#2 C-phase undervoltage element, Y-terminal
27YCA1	PRO	YCAPTUV10	Op.general	CA-phase-to-phase undervoltage element, Y-terminal
27YCA1	PRO	YCAPTUV10	Str.general	CA-phase-to-phase undervoltage element, Y-terminal
27ZA1	PRO	ZAPTUV12	Op.general	#1 A-phase undervoltage element, Z-terminal
27ZA1	PRO	ZAPTUV12	Str.general	#1 A-phase undervoltage element, Z-terminal

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Table L.24   Logical Nodes by Data Source Names (Sheet 2 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
27ZA2	PRO	ZAPTUV15	Op.general	#2 A-phase undervoltage element, Z-terminal
27ZA2	PRO	ZAPTUV15	Str.general	#2 A-phase undervoltage element, Z-terminal
27ZAB1	PRO	ZABPTUV18	Op.general	AB-phase-to-phase undervoltage element, Z-terminal
27ZAB1	PRO	ZABPTUV18	Str.general	AB-phase-to-phase undervoltage element, Z-terminal
27ZB1	PRO	ZBPTUV13	Op.general	#1 B-phase undervoltage element, Z-terminal
27ZB1	PRO	ZBPTUV13	Str.general	#1 B-phase undervoltage element, Z-terminal
27ZB2	PRO	ZBPTUV16	Op.general	#2 B-phase undervoltage element, Z-terminal
27ZB2	PRO	ZBPTUV16	Str.general	#2 B-phase undervoltage element, Z-terminal
27ZBC1	PRO	ZBCPTUV19	Op.general	BC-phase-to-phase undervoltage element, Z-terminal
27ZBC1	PRO	ZBCPTUV19	Str.general	BC-phase-to-phase undervoltage element, Z-terminal
27ZC1	PRO	ZCPTUV14	Op.general	#1 C-phase undervoltage element, Z-terminal
27ZC1	PRO	ZCPTUV14	Str.general	#1 C-phase undervoltage element, Z-terminal
27ZC2	PRO	ZCPTUV17	Op.general	#2 C-phase undervoltage element, Z-terminal
27ZC2	PRO	ZCPTUV17	Str.general	#2 C-phase undervoltage element, Z-terminal
27ZCA1	PRO	ZCAPTUV20	Op.general	CA-phase-to-phase undervoltage element, Z-terminal
27ZCA1	PRO	ZCAPTUV20	Str.general	CA-phase-to-phase undervoltage element, Z-terminal
32GF	PRO	GFRDIR3	Dir.general	Forward directional control for ground overcurrent elements
32GF?0:1	PRO	GFRDIR3	Dir.dirGeneral	If Direction is Forward, value is 1, otherwise 0
32GR	PRO	GRRDIR4	Dir.general	Reverse directional control for ground overcurrent elements
32GR?0:2	PRO	GRRDIR4	Dir.dirGeneral	If direction is reverse, value is 2, otherwise 0
32PF	PRO	PFRDIR5	Dir.general	Forward directional control for phase overcurrent elements
32PF?0:1	PRO	PFRDIR5	Dir.dirGeneral	If direction is forward, value is 1, otherwise 0
32PR	PRO	PRRDIR6	Dir.general	Reverse directional control for phase overcurrent elements
32PR?0:2	PRO	PRRDIR6	Dir.dirGeneral	If direction is reverse, value is 2, otherwise 0
32QF	PRO	QFRDIR1	Dir.general	Forward directional control for negative-sequence overcurrent elements
32QF?0:1	PRO	QFRDIR1	Dir.dirGeneral	If direction is forward, value is 1, otherwise 0
32QR	PRO	QRRDIR2	Dir.general	Reverse directional control for negative-sequence overcurrent elements
32QR?0:2	PRO	QRRDIR2	Dir.dirGeneral	If direction is reverse, value is 2, otherwise 0
3P27Y	PRO	PH3PTUV11	Op.general	Three-phase undervoltage element, Y-terminal
3P27Y	PRO	PH3PTUV11	Str.general	Three-phase undervoltage element, Y-terminal
3P27Z	PRO	PH3PTUV21	Op.general	Three-phase undervoltage element, Z-terminal
3P27Z	PRO	PH3PTUV21	Str.general	Three-phase undervoltage element, Z-terminal
3P59Y	PRO	PH3PTOV10	Str.general	Three-phase overvoltage element, Y-terminal
3P59Z	PRO	PH3PTOV24	Str.general	Three-phase overvoltage element, Z-terminal
3PO	ANN	BKGGIO26	Ind09.stVal	Three-phase pole open
3PO?2:1	PRO	BCCSWI1	Pos.stVal	Three pole open, value is 1 if open, 2 if closed
50A	PRO	APIOC37	Op.general	A-phase instantaneous overcurrent element
50A1	PRO	APIOC25	Op.general	Level 1 A-phase instantaneous overcurrent element
50A2	PRO	APIOC28	Op.general	Level 2 A-phase instantaneous overcurrent element

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Table L.24   Logical Nodes by Data Source Names (Sheet 3 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
50A3	PRO	APIOC31	Op.general	Level 3 A-phase instantaneous overcurrent element
50A4	PRO	APIOC34	Op.general	Level 4 A-phase instantaneous overcurrent element
50B	PRO	BPIOC38	Op.general	B-phase instantaneous overcurrent element
50B1	PRO	BPIOC26	Op.general	Level 1 B-phase instantaneous overcurrent element
50B2	PRO	BPIOC29	Op.general	Level 2 B-phase instantaneous overcurrent element
50B3	PRO	BPIOC32	Op.general	Level 3 B-phase instantaneous overcurrent element
50B4	PRO	BPIOC35	Op.general	Level 4 B-phase instantaneous overcurrent element
50C	PRO	CPIOC39	Op.general	C-phase instantaneous overcurrent element
50C1	PRO	CPIOC27	Op.general	Level 1 C-phase instantaneous overcurrent element
50C2	PRO	CPIOC30	Op.general	Level 2 C-phase instantaneous overcurrent element
50C3	PRO	CPIOC33	Op.general	Level 3 C-phase instantaneous overcurrent element
50C4	PRO	CPIOC36	Op.general	Level 4 C-phase instantaneous overcurrent element
50G1	PRO	GPIOC2	Op.general	Level 1 ground instantaneous overcurrent element
50G2	PRO	GPIOC6	Op.general	Level 2 ground instantaneous overcurrent element
50G3	PRO	GPIOC10	Op.general	Level 3 ground instantaneous overcurrent element
50G4	PRO	GPIOC14	Op.general	Level 4 ground instantaneous overcurrent element
50G5	PRO	GPIOC18	Op.general	Level 5 ground instantaneous overcurrent element
50G6	PRO	GPIOC22	Op.general	Level 6 ground instantaneous overcurrent element
50GF	PRO	GFPIOC46	Op.general	Forward direction ground overcurrent threshold exceeded
50GHIZ	PRO	HIZPHIZ3	Str.general	Ground instantaneous overcurrent
50GHIZA	PRO	HIZPHIZ3	Op.general	Ground instantaneous overcurrent
50GR	PRO	GRPIOC47	Op.general	Reverse direction ground overcurrent threshold exceeded
50L	PRO	LPIOC40	Op.general	Phase instantaneous overcurrent element for load detection
50LA	PRO	LAPIOC41	Op.general	A-phase instantaneous overcurrent element for load detection
50LB	PRO	LBPIOC42	Op.general	B-phase instantaneous overcurrent element for load detection
50LC	PRO	LCPIOC43	Op.general	C-phase instantaneous overcurrent element for load detection
50N1	PRO	NPIOC4	Op.general	Level 1 neutral instantaneous overcurrent element
50N2	PRO	NPIOC8	Op.general	Level 2 neutral instantaneous overcurrent element
50N3	PRO	NPIOC12	Op.general	Level 3 neutral instantaneous overcurrent element
50N4	PRO	NPIOC16	Op.general	Level 4 neutral instantaneous overcurrent element
50N5	PRO	NPIOC20	Op.general	Level 5 neutral instantaneous overcurrent element
50N6	PRO	NPIOC24	Op.general	Level 6 neutral instantaneous overcurrent element
50P1	PRO	PPIOC1	Op.general	Level 1 phase instantaneous overcurrent element
50P2	PRO	PPIOC5	Op.general	Level 2 phase instantaneous overcurrent element
50P3	PRO	PPIOC9	Op.general	Level 3 phase instantaneous overcurrent element
50P4	PRO	PPIOC13	Op.general	Level 4 phase instantaneous overcurrent element
50P5	PRO	PPIOC17	Op.general	Level 5 phase instantaneous overcurrent element
50P6	PRO	PPIOC21	Op.general	Level 6 phase instantaneous overcurrent element
50Q1	PRO	QPIOC3	Op.general	Level 1 negative-sequence instantaneous overcurrent element
50Q2	PRO	QPIOC7	Op.general	Level 2 negative-sequence instantaneous overcurrent element

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Table L.24 Logical Nodes by Data Source Names (Sheet 4 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
50Q3	PRO	QPIOC11	Op.general	Level 3 negative-sequence instantaneous overcurrent element
50Q4	PRO	QPIOC15	Op.general	Level 4 negative-sequence instantaneous overcurrent element
50Q5	PRO	QPIOC19	Op.general	Level 5 negative-sequence instantaneous overcurrent element
50Q6	PRO	QPIOC23	Op.general	Level 6 negative-sequence instantaneous overcurrent element
50QF	PRO	QFPIOC44	Op.general	Forward direction negative-sequence overcurrent threshold exceeded
50QR	PRO	QRPIOC45	Op.general	Reverse direction negative-sequence overcurrent threshold exceeded
51A	PRO	A51PTOC5	Str.general	A-phase time-overcurrent element picked up
51AT	PRO	A51PTOC5	Op.general	A-phase time-overcurrent element timed out
51B	PRO	B51PTOC6	Str.general	B-phase time-overcurrent element picked up
51BT	PRO	B51PTOC6	Op.general	B-phase time-overcurrent element timed out
51C	PRO	C51PTOC7	Str.general	C-phase time-overcurrent element picked up
51CT	PRO	C51PTOC7	Op.general	C-phase time-overcurrent element timed out
51G1	PRO	G51PTOC2	Str.general	#1 Ground time-overcurrent element picked up
51G1T	PRO	G51PTOC2	Op.general	#1 Ground time-overcurrent element timed out
51G2	PRO	G51PTOC3	Str.general	#2 Ground time-overcurrent element picked up
51G2T	PRO	G51PTOC3	Op.general	#2 Ground time-overcurrent element timed out
51N1	PRO	N51PTOC8	Str.general	#1 Neutral time-overcurrent element picked up
51N1T	PRO	N51PTOC8	Op.general	#1 Neutral time-overcurrent element timed out
51N2	PRO	N51PTOC9	Str.general	#2 Neutral time-overcurrent element picked up
51N2T	PRO	N51PTOC9	Op.general	#2 Neutral time-overcurrent element timed out
51P	PRO	P51PTOC1	Str.general	Maximum-phase time-overcurrent element picked up
51PT	PRO	P51PTOC1	Op.general	Maximum-phase time-overcurrent element timed out
51Q	PRO	Q51PTOC4	Str.general	Negative-sequence time-overcurrent element picked up
51QT	PRO	Q51PTOC4	Op.general	Negative-sequence time-overcurrent element timed out
52A3P	ANN	BKGGIO26	Ind04.stVal	Three-phase breaker status
52A3P?1:2	PRO	BSXCBR4	Pos.stVal	Three-phase circuit breaker status, value 2 when closed, 1 when open
52AA	ANN	BKGGIO26	Ind01.stVal	A-phase breaker status
52AA?1:2	PRO	BSAXCBR1	Pos.stVal	A-phase circuit breaker status, value 2 when closed, 1 when open
52AB	ANN	BKGGIO26	Ind02.stVal	B-phase breaker status
52AB?1:2	PRO	BSBXCBR2	Pos.stVal	B-phase circuit breaker status, value 2 when closed, 1 when open
52AC	ANN	BKGGIO26	Ind03.stVal	C-phase breaker status
52AC?1:2	PRO	BSCXCBR3	Pos.stVal	C-phase circuit breaker status, value 2 when closed, 1 when open
59YA1	PRO	YAPTOV1	Str.general	#1 A-phase overvoltage element, Y-terminal
59YA2	PRO	YAPTOV4	Str.general	#2 A-phase overvoltage element, Y-terminal
59YAB1	PRO	YABPTOV7	Str.general	AB-phase-to-phase overvoltage element, Y-terminal
59YB1	PRO	YBPTOV2	Str.general	#1 B-phase overvoltage element, Y-terminal

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Table L.24 Logical Nodes by Data Source Names (Sheet 5 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
59YB2	PRO	YBPTOV5	Str.general	#2 B-phase overvoltage element, Y-terminal
59YBC1	PRO	YBCPTOV8	Str.general	BC-phase-to-phase overvoltage element, Y-terminal
59YC1	PRO	YCPTOV3	Str.general	#1 C-phase overvoltage element, Y-terminal
59YC2	PRO	YCPTOV6	Str.general	#2 C-phase overvoltage element, Y-terminal
59YCA1	PRO	YCAPTOV9	Str.general	CA-phase-to-phase overvoltage element, Y-terminal
59YN1	PRO	YNPTOV12	Str.general	#1 Zero-sequence overvoltage element, Y-terminal
59YN2	PRO	YNPTOV13	Str.general	#2 Zero-sequence overvoltage element, Y-terminal
59YQ1	PRO	YQPTOV11	Str.general	Negative-sequence overvoltage element, Y-terminal
59YV1	PRO	YVPTOV14	Str.general	Positive-sequence overvoltage element, Y-terminal
59ZA1	PRO	ZAPTOV15	Str.general	A-phase overvoltage element, Z-terminal
59ZA2	PRO	ZAPTOV18	Str.general	A-phase overvoltage element, Z-terminal
59ZAB1	PRO	ZABPTOV21	Str.general	AB-phase-to-phase overvoltage element, Z-terminal
59ZB1	PRO	ZBPTOV16	Str.general	B-phase overvoltage element, Z-terminal
59ZB2	PRO	ZBPTOV19	Str.general	B-phase overvoltage element, Z-terminal
59ZBC1	PRO	ZBCPTOV22	Str.general	BC-phase-to-phase overvoltage element, Z-terminal
59ZC1	PRO	ZCPTOV17	Str.general	C-phase overvoltage element, Z-terminal
59ZC2	PRO	ZCPTOV20	Str.general	C-phase overvoltage element, Z-terminal
59ZCA1	PRO	ZCAPTOV23	Str.general	CA-phase-to-phase overvoltage element, Z-terminal
59ZN1	PRO	ZNPTOV26	Str.general	Zero-sequence overvoltage element, Z-terminal
59ZN2	PRO	ZNPTOV27	Str.general	Zero-sequence overvoltage element, Z-terminal
59ZQ1	PRO	ZQPTOV25	Str.general	Negative-sequence overvoltage element, Z-terminal
59ZV1	PRO	ZVPTOV28	Str.general	Positive-sequence overvoltage elements, Z-terminal
79CY3P	PRO	RC3GGIO18	Ind02.stVal	Reclosing relay in the reclose cycle state
79CYA	PRO	RCAGGIO19	Ind02.stVal	A-phase reclosing relay in the reclose cycle state
79CYB	PRO	RCBGGIO20	Ind02.stVal	B-phase reclosing relay in the reclose cycle state
79CYC	PRO	RCCGGIO21	Ind02.stVal	C-phase reclosing relay in the reclose cycle state
79LO3P	PRO	RC3GGIO18	Ind03.stVal	Reclosing relay in the lockout state
79LOA	PRO	RCAGGIO19	Ind03.stVal	A-phase reclosing relay in the lockout state
79LOB	PRO	RCBGGIO20	Ind03.stVal	B-phase reclosing relay in the lockout state
79LOC	PRO	RCCGGIO21	Ind03.stVal	C-phase reclosing relay in the lockout state
79RS3P	PRO	RC3GGIO18	Ind01.stVal	Reclosing relay in the reset state
79RSA	PRO	RCAGGIO19	Ind01.stVal	A-phase reclosing relay in the reset state
79RSB	PRO	RCBGGIO20	Ind01.stVal	B-phase reclosing relay in the reset state
79RSC	PRO	RCCGGIO21	Ind01.stVal	C-phase reclosing relay in the reset state
81D1	PRO	DPTOF1	Str.general	Level 1 instantaneous frequency element
81D1	PRO	DPTUF1	Str.general	Level 1 instantaneous frequency element
81D1T	PRO	DPTOF1	Op.general	Level 1 definite-time frequency element
81D1T	PRO	DPTUF1	Op.general	Level 1 definite-time frequency element
81D2	PRO	DPTOF2	Str.general	Level 2 instantaneous frequency element
81D2	PRO	DPTUF2	Str.general	Level 2 instantaneous frequency element

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Table L.24   Logical Nodes by Data Source Names (Sheet 6 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
81D2T	PRO	DPTOF2	Op.general	Level 2 definite-time frequency element
81D2T	PRO	DPTUF2	Op.general	Level 2 definite-time frequency element
81D3	PRO	DPTOF3	Str.general	Level 3 instantaneous frequency element
81D3	PRO	DPTUF3	Str.general	Level 3 instantaneous frequency element
81D3T	PRO	DPTOF3	Op.general	Level 3 definite-time frequency element
81D3T	PRO	DPTUF3	Op.general	Level 3 definite-time frequency element
81D4	PRO	DPTOF4	Str.general	Level 4 instantaneous frequency element
81D4	PRO	DPTUF4	Str.general	Level 4 instantaneous frequency element
81D4T	PRO	DPTOF4	Op.general	Level 4 definite-time frequency element
81D4T	PRO	DPTUF4	Op.general	Level 4 definite-time frequency element
81D5	PRO	DPTOF5	Str.general	Level 5 instantaneous frequency element
81D5	PRO	DPTUF5	Str.general	Level 5 instantaneous frequency element
81D5T	PRO	DPTOF5	Op.general	Level 5 definite-time frequency element
81D5T	PRO	DPTUF5	Op.general	Level 5 definite-time frequency element
81D6	PRO	DPTOF6	Str.general	Level 6 instantaneous frequency element
81D6	PRO	DPTUF6	Str.general	Level 6 instantaneous frequency element
81D6T	PRO	DPTOF6	Op.general	Level 6 definite-time frequency element
81D6T	PRO	DPTUF6	Op.general	Level 6 definite-time frequency element
ACCESS	ANN	ALMGGIO8	Ind07.stVal	Asserted while any user is logged in at Access Level B or higher
ACCESSP	ANN	ALMGGIO8	Ind13.stVal	Pulses for approximately one second when any user increases access level to B or higher
BADPASS	ANN	ALMGGIO8	Ind09.stVal	Pulses for approximately one second whenever a user enters three successive bad passwords in an SEL ASCII terminal session or web session
BCWA	PRO	BSASCBR1	AbrAlm.stVal	A-phase breaker contact wear has reached 100% wear level
BCWB	PRO	BSBSCBR2	AbrAlm.stVal	B-phase breaker contact wear has reached 100% wear level
BCWC	PRO	BSCSCBR3	AbrAlm.stVal	C-phase breaker contact wear has reached 100% wear level
BTFAIL	ANN	BATGGIO24	Ind04.stVal	Battery failure
CBADA	ANN	MBOKGGIO13	Ind03.stVal	MIRRORED BITS channel A unavailability over threshold
CBADB	ANN	MBOKGGIO13	Ind07.stVal	MIRRORED BITS channel B unavailability over threshold
CC3	PRO	BCCSWI1	OpCls.general	Asserts for one processing interval for **CLOSE** command execution
CC3:OC3	PRO	BCCSWI1	Pos.ctlVal	Circuit breaker close/open command (0 opens, 1 closes)
CCA	PRO	BCACSWI2	OpCls.general	Asserts for one processing interval for **CLOSE** command execution
CCA:OCA	PRO	BCACSWI2	Pos.ctlVal	Circuit breaker close/open command (0 opens, 1 closes)
CCB	PRO	BCBCSWI3	OpCls.general	Asserts for one processing interval for **CLOSE** command execution
CCB:OCB	PRO	BCBCSWI3	Pos.ctlVal	Circuit breaker close/open command
CCC	PRO	BCCCSWI4	OpCls.general	Asserts for one processing interval for **CLOSE** command execution
CCC:OCC	PRO	BCCCSWI4	Pos.ctlVal	C-Phase Circuit Breaker close/open command

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Table L.24   Logical Nodes by Data Source Names (Sheet 7 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
CHGPASS	ANN	ALMGGIO8	Ind10.stVal	Pulses for approximately one second whenever a password changes
CHRGG	ANN	BATGGIO24	Ind01.stVal	Battery is charging
DISCHG	ANN	BATGGIO24	Ind02.stVal	Battery is discharging
DISTST	ANN	BATGGIO24	Ind08.stVal	Asserted when battery discharge test is in progress
DTFAIL	ANN	BATGGIO24	Ind03.stVal	Battery failed discharge test
EN	ANN	TLEDGGIO14	Ind26.stVal	Enabled LED
FLREP	PRO	FLTRDRE1	RcdMade.stVal	Event report present
FLRNUM	PRO	FLTRDRE1	FltNum.stVal	Unique event ID number
GRPSW	ANN	SGGGIO16	Ind09.stVal	Group switch indication
HALARM	ANN	ALMGGIO8	Ind01.stVal	Indication of a diagnostic failure or warning that warrants an ALARM
HALARMA	ANN	ALMGGIO8	Ind04.stVal	Pulses for five seconds per minute until reset when a hardware diagnostic warning occurs
HALARML	ANN	ALMGGIO8	Ind02.stVal	Latches in for relay diagnostic failures
HALARMP	ANN	ALMGGIO8	Ind03.stVal	Pulses for five seconds when a warning diagnostic condition occurs
HBL2AT	ANN	H2BLKGGIO27	Ind03.stVal	A-phase second-harmonic element timed out
HBL2BT	ANN	H2BLKGGIO27	Ind02.stVal	B-phase second-harmonic element timed out
HBL2CT	ANN	H2BLKGGIO27	Ind01.stVal	C-phase second-harmonic element timed out
HBL2T	ANN	H2BLKGGIO27	Ind04.stVal	One or more phase second-harmonic elements timed out
HIF2_A	PRO	HIZPHIZ2	Op.phsA	A-phase HIF detection
HIF2_B	PRO	HIZPHIZ2	Op.phsB	B-phase HIF detection
HIF2_C	PRO	HIZPHIZ2	Op.phsC	C-phase HIF detection
HIFLREP	PRO	HIFRDRE2	RcdMade.stVal	High-impedance event report present
HIFLRNUM	PRO	HIFRDRE2	FltNum.stVal	High-impedance event number
IN101	ANN	IN1GGIO1	Ind01.stVal	Optoisolated input IN101 asserted
IN102	ANN	IN1GGIO1	Ind02.stVal	Optoisolated input IN102 asserted
IN103	ANN	IN1GGIO1	Ind03.stVal	Optoisolated input IN103 asserted
IN104	ANN	IN1GGIO1	Ind04.stVal	Optoisolated input IN104 asserted
IN105	ANN	IN1GGIO1	Ind05.stVal	Optoisolated input IN105 asserted
IN106	ANN	IN1GGIO1	Ind06.stVal	Optoisolated input IN106 asserted
IN107	ANN	IN1GGIO1	Ind07.stVal	Optoisolated input IN107 asserted
IN201	ANN	IN2GGIO2	Ind01.stVal	Optoisolated input IN201 asserted
IN202	ANN	IN2GGIO2	Ind02.stVal	Optoisolated input IN202 asserted
IN203	ANN	IN2GGIO2	Ind03.stVal	Optoisolated input IN203 asserted
IN204	ANN	IN2GGIO2	Ind04.stVal	Optoisolated input IN204 asserted
IN205	ANN	IN2GGIO2	Ind05.stVal	Optoisolated input IN205 asserted
IN206	ANN	IN2GGIO2	Ind06.stVal	Optoisolated input IN206 asserted
INT3P	ANN	INTPTUV23	Op.general	Three-phase voltage interruption element
INT3P	ANN	INTPTUV23	Str.general	Three-phase voltage interruption element
INTA	ANN	INTPTUV23	Op.phsA	A-phase voltage interruption element

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Data Source	Logical Device	Logical Node	Attribute	Comment
INTB	ANN	INTPTUV23	Op.phsB	B-phase voltage interruption element
INTC	ANN	INTPTUV23	Op.phsC	C-phase voltage interruption element
LB01	ANN	LBGGIO17	Ind01.stVal	Local Bit 1 asserted
LB02–LB16	ANN	LBGGIO17	Ind02.stVal–Ind16.stVal	Local Bit 2–16 asserted
LBOKA	ANN	MBOKGGIO13	Ind04.stVal	Loop back MIRRORED BITS data OK, Channel A
LBOKB	ANN	MBOKGGIO13	Ind08.stVal	Loop back MIRRORED BITS data OK, Channel B
LINK5A	ANN	ETHGGIO23	Ind02.stVal	Asserted when a valid link is detected on port 5A
LINK5B	ANN	ETHGGIO23	Ind04.stVal	Asserted when a valid link is detected on port 5B
LNKFAIL	ANN	ETHGGIO23	Ind05.stVal	Asserted when a valid link is not detected on the active port(s)
LOP	ANN	LOPPTUV1	Op.general	Internal loss-of-potential element
LOP	ANN	LOPPTUV1	Str.general	Internal loss-of-potential element
LT01	ANN	LTGGIO7	Ind01.stVal	Latch Bit 1 asserted
LT02–LT32	ANN	LTGGIO7	Ind02.stVal–Ind32.stVal	Latch Bit 2–32 asserted
MAXWEAR	PRO	BSASCBR1	MaxAbrPrt.instMag.f	Greatest wear of WEARA, WEARB, or WEARC
MAXWEAR	PRO	BSBSCBR2	MaxAbrPrt.instMag.f	Greatest wear of WEARA, WEARB, or WEARC
MAXWEAR	PRO	BSCSCBR3	MaxAbrPrt.instMag.f	Greatest wear of WEARA, WEARB, or WEARC
MV01	ANN	MVGGIO28	AnIn01.instMag.f	Math variable 1
MV02–MV64	ANN	MVGGIO28	AnIn02.instMag.f–AnIn64.instMag.f	Math variable 2–64
OC3	PRO	BCCSWI1	OpOpn.general	Asserts for one processing interval for **OPEN** command execution
OC3	PRO	BSASCBR1	ColOpn.stVal	Asserts for one processing interval for **OPEN** command execution
OC3	PRO	BSBSCBR2	ColOpn.stVal	Asserts for one processing interval for **OPEN** command execution
OC3	PRO	BSCSCBR3	ColOpn.stVal	Asserts for one processing interval for **OPEN** command execution
OCA	PRO	BCACSWI2	OpOpn.general	Asserts for one processing interval for **OPEN** command execution on A-phase
OCA	PRO	BSASCBR1	ColOpn.stVal	Asserts for one processing interval for **OPEN** command execution on A-phase
OCB	PRO	BCBCSWI3	OpOpn.general	Asserts for one processing interval for **OPEN** command execution on B-phase
OCB	PRO	BSBSCBR2	ColOpn.stVal	Asserts for one processing interval for **OPEN** command execution on B-phase
OCC	PRO	BCCCSWI4	OpOpn.general	Asserts for one processing interval for **OPEN** command execution on C-phase
OCC	PRO	BSCSCBR3	ColOpn.stVal	Asserts for one processing interval for **OPEN** command execution on C-phase
OPSCTRA	PRO	BSASCBR1	OpCnt.stVal	A-phase operations counter
OPSCTRA	PRO	BSAXCBR1	OpCnt.stVal	A-phase operations counter
OPSCTRB	PRO	BSASCBR2	OpCnt.stVal	B-phase operations counter
OPSCTRB	PRO	BSAXCBR2	OpCnt.stVal	B-phase operations counter

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Table L.24 Logical Nodes by Data Source Names (Sheet 9 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
OPSCTRC	PRO	BSASCBR3	OpCnt.stVal	C-phase operations counter
OPSCTRC	PRO	BSAXCBR3	OpCnt.stVal	C-phase operations counter
OREDHIF2	PRO	HIZPHIZ2	Op.general	HIF detection
OREDHIF2	PRO	HIZPHIZ2	Str.general	HIF detection
OUT101	ANN	OUT1GGIO3	Ind01.stVal	Output contact OUT101 asserted
OUT102	ANN	OUT1GGIO3	Ind02.stVal	Output contact OUT102 asserted
OUT103	ANN	OUT1GGIO3	Ind03.stVal	Output contact OUT103 asserted
OUT104	ANN	OUT1GGIO3	Ind04.stVal	Output contact OUT104 asserted
OUT105	ANN	OUT1GGIO3	Ind05.stVal	Output contact OUT105 asserted
OUT106	ANN	OUT1GGIO3	Ind06.stVal	Output contact OUT106 asserted
OUT107	ANN	OUT1GGIO3	Ind07.stVal	Output contact OUT107 asserted
OUT108	ANN	OUT1GGIO3	Ind08.stVal	Output contact OUT108 asserted
OUT201	ANN	OUT2GGIO4	Ind01.stVal	Output contact OUT201 asserted
OUT202	ANN	OUT2GGIO4	Ind02.stVal	Output contact OUT202 asserted
P5ASEL	ANN	ETHGGIO23	Ind01.stVal	Asserted when port 5A is active
P5BSEL	ANN	ETHGGIO23	Ind03.stVal	Asserted when port 5B is active
PASNVAL	ANN	ALMGGIO8	Ind14.stVal	Pulses for approximately one second when an incorrect password is entered when attempting to enter Access Level B or higher, or when changing passwords
PB01_LED	ANN	PBGGIO22	Ind01.stVal	Operator control pushbutton LED 1
PB02_LED–PB12_LED	ANN	PBGGIO22	Ind02.stVal–Ind12.stVal	Operator control pushbutton LED 2–12
PWR_SRC1	ANN	BATGGIO24	Ind06.stVal	Recloser control power supply is operating from external power source
RB01	CON	RBGGIO1	SPCSO01.ctlVal	Remote Bit 1
RB01	CON	RBGGIO1	SPCSO01.stVal	Remote Bit 1
RB02–RB32	CON	RBGGIO1	SPCSO02.ctlVal–SPCSO32.ctlVal	Remote Bit 2–32
RB02–RB32	CON	RBGGIO1	SPCSO02.stVal–SPCSO32.stVal	Remote Bit 2–32
RBADA	ANN	MBOKGGIO13	Ind02.stVal	MIRRORED BITS channel A outage duration over threshold
RBADB	ANN	MBOKGGIO13	Ind06.stVal	MIRRORED BITS channel B outage duration over threshold
RMB1A	ANN	RMBAGGIO9	Ind01.stVal	Channel A received MIRRORED BIT 1
RMB1B	ANN	RMBBGGIO11	Ind01.stVal	Channel B received MIRRORED BIT 1
RMB2A–RMB8A	ANN	RMBAGGIO9	Ind02.stVal–Ind08.stVal	Channel A received MIRRORED BIT 2–8
RMB2B–RMB8B	ANN	RMBBGGIO11	Ind02.stVal–Ind08.stVal	Channel B received MIRRORED BIT 2–8
ROKA	ANN	MBOKGGIO13	Ind01.stVal	Received MIRRORED BITS data OK, Channel A
ROKB	ANN	MBOKGGIO13	Ind05.stVal	Received MIRRORED BITS data OK, Channel B
SAG3P	PRO	SAGPTUV22	Op.general	Three-phase voltage SAG element
SAG3P	PRO	SAGPTUV22	Str.general	Three-phase voltage SAG element
SAGA	PRO	SAGPTUV22	Op.phsA	A-phase voltage SAG element

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Data Source	Logical Device	Logical Node	Attribute	Comment
SAGB	PRO	SAGPTUV22	Op.phsB	B-phase voltage SAG element
SAGC	PRO	SAGPTUV22	Op.phsC	C-phase voltage SAG element
SALARM	ANN	ALMGGIO8	Ind08.stVal	Indication of software or user activity that warrants an ALARM
SETCHG	ANN	ALMGGIO8	Ind11.stVal	Pulses for approximately one second whenever settings are changed
SG1	ANN	SGGGIO16	Ind01.stVal	Setting group indication, group 1
SG2	ANN	SGGGIO16	Ind02.stVal	Setting group indication, group 2
SG3	ANN	SGGGIO16	Ind03.stVal	Setting group indication, group 3
SG4	ANN	SGGGIO16	Ind04.stVal	Setting group indication, group 4
SG5	ANN	SGGGIO16	Ind05.stVal	Setting group indication, group 5
SG6	ANN	SGGGIO16	Ind06.stVal	Setting group indication, group 6
SG7	ANN	SGGGIO16	Ind07.stVal	Setting group indication, group 7
SG8	ANN	SGGGIO16	Ind08.stVal	Setting group indication, group 8
SH03P	ANN	RC3GGIO18	Ind04.stVal	Reclosing relay shot counter = 0
SH0A	ANN	RCAGGIO19	Ind04.stVal	A-phase reclosing relay shot counter = 0
SH0B	ANN	RCBGGIO20	Ind04.stVal	B-phase reclosing relay shot counter = 0
SH0C	ANN	RCCGGIO21	Ind04.stVal	C-phase reclosing relay shot counter = 0
SH13P	ANN	RC3GGIO18	Ind05.stVal	Reclosing relay shot counter = 1
SH1A	ANN	RCAGGIO19	Ind05.stVal	A-phase reclosing relay shot counter = 1
SH1B	ANN	RCBGGIO20	Ind05.stVal	B-phase reclosing relay shot counter = 1
SH1C	ANN	RCCGGIO21	Ind05.stVal	C-phase reclosing relay shot counter = 1
SH23P	ANN	RC3GGIO18	Ind06.stVal	Reclosing relay shot counter = 2
SH2A	ANN	RCAGGIO19	Ind06.stVal	A-phase reclosing relay shot counter = 2
SH2B	ANN	RCBGGIO20	Ind06.stVal	B-phase reclosing relay shot counter = 2
SH2C	ANN	RCCGGIO21	Ind06.stVal	C-phase reclosing relay shot counter = 2
SH33P	ANN	RC3GGIO18	Ind07.stVal	Reclosing relay shot counter = 3
SH3A	ANN	RCAGGIO19	Ind07.stVal	A-phase reclosing relay shot counter = 3
SH3B	ANN	RCBGGIO20	Ind07.stVal	B-phase reclosing relay shot counter = 3
SH3C	ANN	RCCGGIO21	Ind07.stVal	C-phase reclosing relay shot counter = 3
SH43P	ANN	RC3GGIO18	Ind08.stVal	Reclosing relay shot counter = 4
SH4A	ANN	RCAGGIO19	Ind08.stVal	A-phase reclosing relay shot counter = 4
SH4B	ANN	RCBGGIO20	Ind08.stVal	B-phase reclosing relay shot counter = 4
SH4C	ANN	RCCGGIO21	Ind08.stVal	C-phase reclosing relay shot counter = 4
SPO	ANN	BKGGIO26	Ind08.stVal	Any phase single pole open
SPOA	ANN	BKGGIO26	Ind05.stVal	A-phase single pole open
SPOA?2:1	PRO	BCACSWI2	Pos.stVal	Phase A single pole/phase open conditions, Open = 1, Closed = 2.
SPOB	ANN	BKGGIO26	Ind06.stVal	B-phase single pole open
SPOB?2:1	PRO	BCBCSWI3	Pos.stVal	Phase B single pole/phase open conditions, Open = 1, Closed = 2.
SPOC	ANN	BKGGIO26	Ind07.stVal	C-phase single pole open

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Data Source	Logical Device	Logical Node	Attribute	Comment
SPOC?2:1	PRO	BCCCSWI4	Pos.stVal	Phase C single pole/phase open conditions, Open = 1, Closed = 2.
SV01	ANN	SVGGIO5	Ind01.stVal	SELOGIC Variable 1
SV01T	ANN	SVTGGIO6	Ind01.stVal	SELOGIC Variable SV01 timer output asserted
SV02–SV64	ANN	SVGGIO5	Ind02.stVal–Ind64.stVal	SELOGIC Variable 2–64
SV02T–SV64T	ANN	SVTGGIO6	Ind02.stVal–Ind64.stVal	SELOGIC Variable SV02–64 timer output asserted
SW3P	PRO	SWLPTOV29	Op.general	Three-phase voltage swell element
SW3P	PRO	SWLPTOV29	Str.general	Three-phase voltage swell element
SWA	PRO	SWLPTOV29	Op.phsA	A-phase voltage swell element
SWB	PRO	SWLPTOV29	Op.phsB	B-phase voltage swell element
SWC	PRO	SWLPTOV29	Op.phsC	C-phase voltage swell element
TCCAP	ANN	BATGGIO24	Ind07.stVal	Recloser interface trip and close capacitor fully charged
TLED_01	ANN	TLEDGGIO14	Ind01.stVal	Target LEDs 01
TLED_02–TLED_24	ANN	TLEDGGIO14	Ind02.stVal–Ind24.stVal	Target LEDs 02–24
TMB1A	ANN	TMBAGGIO10	Ind01.stVal	Channel A transmitted MIRRORED BIT 1
TMB1B	ANN	TMBBGGIO12	Ind01.stVal	Channel B transmitted MIRRORED BIT 1
TMB2A	ANN	TMBAGGIO10	Ind02.stVal	Channel A transmitted MIRRORED BIT 2
TMB2B	ANN	TMBBGGIO12	Ind02.stVal	Channel B transmitted MIRRORED BIT 2
TMB3A	ANN	TMBAGGIO10	Ind03.stVal	Channel A transmitted MIRRORED BIT 3
TMB3B	ANN	TMBBGGIO12	Ind03.stVal	Channel B transmitted MIRRORED BIT 3
TMB4A	ANN	TMBAGGIO10	Ind04.stVal	Channel A transmitted MIRRORED BIT 4
TMB4B	ANN	TMBBGGIO12	Ind04.stVal	Channel B transmitted MIRRORED BIT 4
TMB5A	ANN	TMBAGGIO10	Ind05.stVal	Channel A transmitted MIRRORED BIT 5
TMB5B	ANN	TMBBGGIO12	Ind05.stVal	Channel B transmitted MIRRORED BIT 5
TMB6A	ANN	TMBAGGIO10	Ind06.stVal	Channel A transmitted MIRRORED BIT 6
TMB6B	ANN	TMBBGGIO12	Ind06.stVal	Channel B transmitted MIRRORED BIT 6
TMB7A	ANN	TMBAGGIO10	Ind07.stVal	Channel A transmitted MIRRORED BIT 7
TMB7B	ANN	TMBBGGIO12	Ind07.stVal	Channel B transmitted MIRRORED BIT 7
TMB8A	ANN	TMBAGGIO10	Ind08.stVal	Channel A transmitted MIRRORED BIT 8
TMB8B	ANN	TMBBGGIO12	Ind08.stVal	Channel B transmitted MIRRORED BIT 8
TOSLP	ANN	BATGGIO24	Ind05.stVal	To Sleep. Asserts for last minute of control operation on battery power.
TRIP3P	PRO	TRIPPTRC1	Tr.general	Three-phase Trip logic output asserted
TRIPA	PRO	TRIPPTRC1	Tr.phsA	A-Phase Trip logic output asserted
TRIPB	PRO	TRIPPTRC1	Tr.phsB	B-Phase Trip logic output asserted
TRIPC	PRO	TRIPPTRC1	Tr.phsC	C-Phase Trip logic output asserted
TRIPLED	ANN	TLEDGGIO14	Ind25.stVal	Trip target LED
VB001[a]	ANN	VBGGIO15	Ind001.stVal	Virtual Bit 001

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Table L.24   Logical Nodes by Data Source Names (Sheet 12 of 12)

Data Source	Logical Device	Logical Node	Attribute	Comment
VB002–VB128[a]	ANN	VBGGIO15	Ind002.stVal–Ind128.stVal	Virtual Bit 002–128
WEARA	PRO	BSASCBR1	AbrPrt.instMag.f	A-phase breaker wear percentage
WEARB	PRO	BSBSCBR2	AbrPrt.instMag.f	B-phase breaker wear percentage
WEARC	PRO	BSCSCBR3	AbrPrt.instMag.f	C-phase breaker wear percentage

[a] Virtual bits retain state until overwritten or device is restarted.

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Table L.25 and *Table L.26* are as shown in the IEC 61850 standard, Part 8-1, Section 24. Note that because the standard explicitly dictates which services and functions must be implemented to achieve conformance, only the optional services and functions are listed.

Table L.25   PICS for A-Profile Support

	Profile	Client	Server	Value/Comment
A1	Client/Server	N	Y	
A2	GOOSE/GSE management	Y	Y	Only GOOSE, not GSSE
A3	GSSE	N	N	
A4	Time Sync	N	Y	

Table L.26   PICS for T-Profile Support

	Profile	Client	Server	Value/Comment
T1	TCP/IP	N	Y	
T2	OSI	N	N	
T3	GOOSE/GSE	Y	Y	Only GOOSE, not GSSE
T4	GSSE	N	N	
T5	Time Sync	N	Y	

Refer to the *ACSI Conformance Statements on page L.58* for information on the supported services.

MMS Conformance

The Manufacturing Message Specification (MMS) stack provides the basis for many IEC 61850 protocol services. *Table L.27* defines the service support requirement and restrictions of the MMS services in SEL-651R-2 devices. Generally, only those services whose implementation is not mandatory are shown. Refer to the IEC 61850 standard Part 8-1 for more information.

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Table L.27   MMS Service Supported Conformance (Sheet 1 of 3)

MMS Service Supported CBB	Client-CR Supported	Server-CR Supported
status		Y
getNameList		Y
identify		Y
rename		
read		Y
write		Y
getVariableAccessAttributes		Y
defineNamedVariable		
defineScatteredAccess		
getScatteredAccessAttributes		
deleteVariableAccess		
defineNamedVariableList		
getNamedVariableListAttributes		Y
deleteNamedVariableList		
defineNamedType		
getNamedTypeAttributes		
deleteNamedType		
input		
output		
takeControl		
relinquishControl		
defineSemaphore		
deleteSemaphore		
reportPoolSemaphoreStatus		
reportSemaphoreStatus		
initiateDownloadSequence		
downloadSegment		
terminateDownloadSequence		
initiateUploadSequence		
uploadSegment		
terminateUploadSequence		
requestDomainDownload		
requestDomainUpload		
loadDomainContent		
storeDomainContent		
deleteDomain		
getDomainAttributes		Y
createProgramInvocation		
deleteProgramInvocation		
start		

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Table L.27 MMS Service Supported Conformance (Sheet 2 of 3)

MMS Service Supported CBB	Client-CR Supported	Server-CR Supported
stop		
resume		
reset		
kill		
getProgramInvocationAttributes		
obtainFile		Y
defineEventCondition		
deleteEventCondition		
getEventConditionAttributes		
reportEventConditionStatus		
alterEventConditionMonitoring		
triggerEvent		
defineEventAction		
deleteEventAction		
alterEventEnrollment		
reportEventEnrollmentStatus		
getEventEnrollmentAttributes		
acknowledgeEventNotification		
getAlarmSummary		
getAlarmEnrollmentSummary		
readJournal		
writeJournal		
initializeJournal		
reportJournalStatus		
createJournal		
deleteJournal		
fileOpen		Y
fileRead		Y
fileClose		Y
fileRename		
fileDelete		Y
fileDirectory		Y
unsolicitedStatus		
informationReport		Y
eventNotification		
attachToEventCondition		
attachToSemaphore		
conclude		Y
cancel		Y
getDataExchangeAttributes		

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Table L.27   MMS Service Supported Conformance (Sheet 3 of 3)

MMS Service Supported CBB	Client-CR Supported	Server-CR Supported
exchangeData		
defineAccessControlList		
getAccessControlListAttributes		
reportAccessControlledObjects		
deleteAccessControlList		
alterAccessControl		
reconfigureProgramInvocation		

Table L.28 lists specific settings for the MMS parameter Conformance Building Block (CBB).

Table L.28   MMS Parameter CBB

MMS Parameter CBB	Client-CR Supported	Server-CR Supported
STR1		Y
STR2		Y
VNAM		Y
VADR		Y
VALT		Y
TPY		Y
VLIS		Y
CEI		

The following variable access conformance statements are listed in the order specified in the IEC 61850 standard, Part 8-1. Generally, only those services whose implementation is not mandatory are shown. Refer to the IEC 61850 standard Part 8-1 for more information.

Table L.29   AlternateAccessSelection Conformance Statement

AlternateAccessSelection	Client-CR Supported	Server-CR Supported
accessSelection		Y
component		Y
index		
indexRange		
allElements		
alternateAccess		Y
selectAccess		Y
component		Y
index		
indexRange		
allElements		

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Table L.30   VariableAccessSpecification Conformance Statement

VariableAccessSpecification	Client-CR Supported	Server-CR Supported
listOfVariable		Y
variableSpecification		Y
alternateAccess		Y
variableListName		Y

Table L.31   VariableSpecification Conformance Statement

VariableSpecification	Client-CR Supported	Server-CR Supported
name		Y
address		
variableDescription		
scatteredAccessDescription		
invalidated		

Table L.32   Read Conformance Statement

Read	Client-CR Supported	Server-CR Supported
Request		
specificationWithResult		
variableAccessSpecification		
Response		
variableAccessSpecification		Y
listOfAccessResult		Y

Table L.33   GetVariableAccessAttributes Conformance Statement

GetVariableAccessAttributes	Client-CR Supported	Server-CR Supported
Request		
name		
address		
Response		
mmsDeletable		
address		
typeSpecification		

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Table L.34   DefineNamedVariableList Conformance Statement

DefineVariableAccessAttributes	Client-CR Supported	Server-CR Supported
Request		
variableListName		
listOfVariable		
variableSpecification		
alternateAccess		
Response		

Table L.35   GetNamedVariableListAttributes Conformance Statement

GetNamedVariableListAttributes	Client-CR Supported	Server-CR Supported
Request		
ObjectName		
Response		
mmsDeletable		Y
listOfVariable		Y
variableSpecification		Y
alternateAccess		Y

Table L.36   DeleteNamedVariableList Conformance Statement

DeleteNamedVariableList	Client-CR Supported	Server-CR Supported
Request		
Scope		
listOfVariableListName		
domainName		
Response		
numberMatched		
numberDeleted		
DeleteNamedVariableList-Error		

GOOSE Services Conformance Statement

Table L.37   GOOSE Conformance

	Subscriber	Publisher	Value/Comment
GOOSE Services	Y	Y	
SendGOOSEMessage		Y	
GetGoReference			
GetGOOSEElementNumber			
GetGoCBValues		Y	
SetGoCBValues			
GSENotSupported			
GOOSE Control Block (GoCB)		Y	

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Table L.38 ACSI Basic Conformance Statement

	Services	Client/Subscriber	Server/Publisher	SEL-651R-2 Support
	Client-Server Roles			
B11	Server side (of Two-Party Application-Association)	–	c1[a]	YES
B12	Client side (of Two-Party Application-Association)	c1[a]	–	
	SCMS Supported			
B21	SCSM: IEC 61850-8-1 used			YES
B22	SCSM: IEC 61850-9-1 used			
B23	SCSM: IEC 61850-9-2 used			
B24	SCSM: other			
	Generic Substation Event Model (GSE)			
B31	Publisher side	–	O[b]	YES
B32	Subscriber side	O[b]	–	YES
	Transmission of Sampled Value Model (SVC)			
B41	Publisher side	–	O[b]	
B42	Subscriber side	O[b]	–	

[a] c1 shall be mandatory if support for LOGICAL-DEVICE model has been declared.
[b] O = optional.

Table L.39 ACSI Models Conformance Statement (Sheet 1 of 2)

	Models	Client/Subscriber	Server/Publisher	SEL-651R-2 Support
	If Server Side (B11) Supported			
M1	Logical device	c2[a]	c2[a]	YES
M2	Logical node	c3[b]	c3[b]	YES
M3	Data	c4[c]	c4[c]	YES
M4	Dataset	c5[d]	c5[d]	YES
M5	Substitution	O[e]	O[e]	
M6	Setting group control	O[e]	O[e]	
	Reporting			
M7	Buffered report control	O[e]	O[e]	YES
M7-1	sequence-number			YES
M7-2	report-time-stamp			YES
M7-3	reason-for-inclusion			YES
M7-4	data-set-name			YES
M7-5	data-reference			YES
M7-6	buffer-overflow			YES
M7-7	entryID			YES
M7-8	BufTm			YES
M7-9	IntgPd			YES
M7-10	GI			YES

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Table L.39   ACSI Models Conformance Statement (Sheet 2 of 2)

	Models	Client/Subscriber	Server/Publisher	SEL-651R-2 Support
M8	Unbuffered report control	O[e]	O[e]	YES
M8-1	sequence-number			YES
M8-2	report-time-stamp			YES
M8-3	reason-for-inclusion			YES
M8-4	data-set-name			YES
M8-5	data-reference			YES
M8-6	BufTm			YES
M8-7	IntgPd			YES
M8-8	GI			YES
	Logging	O[e]	O[e]	
M9	Log control	O[e]	O[e]	
M9-1	IntgPd			
M10	Log	O[e]	O[e]	
M11	Control	M[f]	M[f]	YES
If GSE (B31/32) Is Supported				
M12	GOOSE	O[e]	O[e]	YES
M12-1	entryID			YES
M12-2	DataReflnc			YES
M13	GSSE	O[e]	O[e]	
If GSE (B41/42) Is Supported				
M14	Multicast SVC	O[e]	O[e]	
M15	Unicast SVC	O[e]	O[e]	
M16	Time	M[f]	M[f]	YES
M17	File Transfer	O[e]	O[e]	YES

[a] c2 shall be "M" if support for LOGICAL-NODE model has been declared.
[b] c3 shall be "M" if support for DATA model has been declared.
[c] c4 shall be "M" if support for DATA-SET, Substitution, Report, Log Control, or Time model has been declared.
[d] c5 shall be "M" if support for Report, GSE, or SV models has been declared.
[e] O = optional.
[f] M = mandatory.

Table L.40   ACSI Services Conformance Statement (Sheet 1 of 4)

	Services	AA: TP/MC	Client/ Subscriber	Server/Publisher	SEL-651R-2 Support
Server (Clause 6)					
S1	ServerDirectory	TP		M[a]	YES
Application Association (Clause 7)					
S2	Associate		M[a]	M[a]	YES
S3	Abort		M[a]	M[a]	YES
S4	Release		M[a]	M[a]	YES
Logical Device (Clause 8)					
S5	LogicalDeviceDirectory	TP	M[a]	M[a]	YES

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Table L.40 ACSI Services Conformance Statement (Sheet 2 of 4)

	Services	AA: TP/MC	Client/ Subscriber	Server/Publisher	SEL-651R-2 Support
Logical Node (Clause 9)					
S6	LogicalNodeDirectory	TP	M[a]	M[a]	YES
S7	GetAllDataValues	TP	O[b]	M[a]	YES
Data (Clause 10)					
S8	GetDataValues	TP	M[a]	M[a]	YES
S9	SetDataValues	TP	O[b]	O[b]	
S10	GetDataDirectory	TP	O[b]	M[a]	YES
S11	GetDataDefinition	TP	O[b]	M[a]	YES
Dataset (Clause 11)					
S12	GetDataSetValues	TP	O[b]	M[a]	YES
S13	SetDataSetValues	TP	O[b]	O[b]	
S14	CreateDataSet	TP	O[b]	O[b]	
S15	DeleteDataSet	TP	O[b]	O[b]	
S16	GetDataSetDirectory	TP	O[b]	O[b]	YES
Substitution (Clause 12)					
S17	SetDataValues	TP	M[a]	M[a]	
Settings Group Control (Clause 13)					
S18	SelectActiveSG	TP	O[b]	O[b]	
S19	SelectEditSG	TP	O[b]	O[b]	
S20	SetSGvalues	TP	O[b]	O[b]	
S21	ConfirmEditSGVal	TP	O[b]	O[b]	
S22	GetSGValues	TP	O[b]	O[b]	
S23	GetSGCBValues	TP	O[b]	O[b]	
Reporting (Clause 14)					
Buffered Report Control Block (BRCB)					
S24	Report	TP	c6[c]	c6[c]	YES
S24-1	data-change (dchg)				YES
S24-2	qchg-change (qchg)				YES
S24-3	data-update (dupd)				
S25	GetBRCBValues	TP	c6[c]	c6[c]	YES
S26	SetBRCBValues	TP	c6[c]	c6[c]	YES
Unbuffered Report Control Block (URCB)					
S27	Report	TP	c6[c]	c6[c]	YES
S27-1	data-change (dchg)				YES
S27-2	qchg-change (qchg)				YES
S27-3	data-update (dupd)				
S28	GetURCBValues	TP	c6[c]	c6[c]	YES
S29	SetURCBValues	TP	c6[c]	c6[c]	YES

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Table L.40   ACSI Services Conformance Statement (Sheet 3 of 4)

	Services	AA: TP/MC	Client/ Subscriber	Server/Publisher	SEL-651R-2 Support
	Logging (Clause 14)				
	Log Control Block				
S30	GetLCBValues	TP	M[a]	M[a]	
S31	SetLCBValues	TP	O[b]	M[a]	
LOG					
S32	QueryLogByTime	TP	c7[d]	M[a]	
S33	QueryLogByEntry	TP	c7[d]	M[a]	
S34	GetLogStatusValues	TP	M[a]	M[a]	
	Generic Substation Event Model (GSE) (Clause 14.3.5.3.4.)				
	GOOSE-Control-Block				
S35	SendGOOSEMessage	MC	c8[e]	c8[e]	YES
S36	GetReference	TP	O[b]	c9[f]	
S37	GetGOOSEElementNumber	TP	O[b]	c9[f]	
S38	GetGoCBValues	TP	O[b]	O[b]	YES
S39	SetGoCBValues	TP	O[b]	O[b]	
	GSSE-Control-Block				
S40	SendGSSEMessage	MC	c8[e]	c8[e]	
S41	GetReference	TP	O[b]	c9[f]	
S42	GetGSSEElementNumber	TP	O[b]	c9[f]	
S43	GetGsCBValues	TP	O[b]	O[b]	
S44	SetGsCBValues	TP	O[b]	O[b]	
	Transmission of Sample Value Model (SVC) (Clause 16)				
	Multicast SVC				
S45	SendMSVMessage	MC	c10[g]	c10[g]	
S46	GetMSVCBValues	TP	O[b]	O[b]	
S47	SetMSVCBValues	TP	O[b]	O[b]	
	Unicast SVC				
S48	SendUSVMessage	MC	c10[g]	c10[g]	
S49	GetUSVCBValues	TP	O[b]	O[b]	
S50	SetUSVCBValues	TP	O[b]	O[b]	
	Control (Clause 16.4.8)				
S51	Select		M[a]	O[b]	
S52	SelectWithValue	TP	M[a]	O[b]	YES
S53	Cancel	TP	O[b]	M[a]	YES
S54	Operate	TP	M[a]	M[a]	YES
S55	Commmand-Termination	TP	M[a]	M[a]	YES
S56	TimeActivated-Operate	TP	O[b]	O[b]	

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Table L.40   ACSI Services Conformance Statement (Sheet 4 of 4)

	Services	AA: TP/MC	Client/ Subscriber	Server/Publisher	SEL-651R-2 Support
	File Transfer (Clause 20)				
S57	GetFile	TP	O[b]	M[a]	YES
S58	SetFile	TP	O[b]	O[b]	
S59	DeleteFile	TP	O[b]	O[b]	
S60	GetFileAttributeValues	TP	O[b]	M[a]	YES
	Time (Clause 5.5)				
T1	Time resolution of internal clock (nearest negative power of 2 in seconds)			2–10 (1 ms)	T1
T2	Time accuracy of internal clock				10/9
	T1				YES
	T2				YES
	T3				YES
	T4				YES
	T5				YES
T3	Supported TimeStamp resolution (nearest negative power of 2 in seconds)			2–10 (1 ms)	10

[a] M = mandatory.
[b] O = optional.
[c] c6 shall declare support for at least one (BRCB or URCB).
[d] c7 shall declare support for at least one (QueryLogByTime or QueryLogAfter).
[e] c8 shall declare support for at least one (SendGOOSEMessage or SendGSSEMessage).
[f] c9 shall declare support if TP association is available.
[g] c10 shall declare support for at least one (SendMSVMessage or SendUSVMessage).

Appendix M

Cybersecurity Features

The SEL-651R-2 provides a number of features to help meet cybersecurity design requirements.

Access Control

The SEL-651R-2 has a number of mechanisms for managing electronic access. These include ways to limit access, provide user authentication, and monitor electronic and physical access.

Physical Port Controls

Each physical serial port and the Ethernet port can be individually disabled by using the EPORT setting. By default, all of the ports are enabled. It is good security practice to disable unused ports.

IP Ports

When using Ethernet, there are a number of IP ports available within the SEL-651R-2. Many of these IP port numbers are configurable. All IP ports can be disabled and are disabled by default. *Table M.1* describes each of these.

Table M.1   IP Port Numbers

IP Port Default	Port Selection Setting	Network Protocol	Default Port State	Port Enable Setting	Purpose
21	—	TCP	Disabled	EFTPSERV	FTP protocol access for file transfer of settings and reports
23	TPORT	TCP	Disabled	ETELNET	Telnet access for general engineering terminal access
80	HTTPPORT	TCP	Disabled	EHTTP	Web server access to read various relay information
102	—	TCP	Disabled	E61850	IEC 61850 MMS for SCADA functionality
123	SNTPPORT	UDP	Disabled	ESNTP	SNTP time synchronization
4712/ 4713	PMOTCP1/ PMOUDP1	TCP/UDP	Disabled	PMOTS1	Synchrophasor data output, session 1
4722/ 4713	PMOTCP2/ PMOUDP2	TCP/UDP	Disabled	PMOTS2	Synchrophasor data output, session 2
20000	DNPNUM	TCP/UDP	Disabled	EDNP	DNP for SCADA functionality
502	—	TCP	Disabled	EMODBUS	Modbus for SCADA functionality

See *Port 5 Settings on page SET.70* for more information on these settings.

Authentication and Authorization

The SEL-651R-2 supports four levels of access, as described in *Port Access Levels on page 10.21*. Refer to this section to learn how each level is accessed and how to change passwords. It is good security practice to change the default passwords of each access level and to use a unique password for each level.

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The MAXACC setting limits the level of access for each port. This permits you to operate under the principle of "least privilege", restricting ports to the levels necessary for the functions performed on those ports.

The SEL-651R-2 supports strong passwords with as many as 12 characters, using any printable character, allowing users to select complex passwords if they so choose. SEL recommends that passwords have a minimum of eight characters and include at least one of each of the following: lowercase letter, uppercase letter, number, and special character.

Monitoring and Logging

The SEL-651R-2 provides Relay Word bits that are useful for monitoring relay access:

➤ BADPASS—Pulses for approximately one second if a user enters three successive incorrect passwords in an SEL ASCII terminal session or web session.

➤ ACCESS—Asserted while any user is logged in to Access Level B or higher.

➤ ACCESSP—Pulses for approximately one second whenever a user gains access to Access Level B or higher.

➤ PASNVAL—Pulses for approximately one second when an incorrect password is entered when attempting to enter Access Level B or higher, or when an incorrect password is entered when attempting to change passwords.

➤ LINK5, LINK5A, LINK5B—Asserted while the link is active on the Ethernet port(s). Loss of link can be an indication that an Ethernet cable has been disconnected.

➤ LNKFAIL—Asserted if link is lost on the active IP port (Ports 5, 5A, or 5B).

These bits can be mapped for SCADA monitoring via DNP3, IEC 61850, Modbus, or SEL Fast Message. They also may be added to the SER for later analysis or assigned to output contacts for alarm purposes.

The SEL-651R-2 SER is a useful tool for capturing a variety of relay events. In addition to capturing state changes of user-selected Relay Word bits, it captures all startups, settings changes, and group switches. See *Sequential Events Recorder (SER) Report on page 12.39* for more information about SER.

Physical Access Security

Physical security of cybersecurity assets is a common concern. SEL-651R-2 recloser controls can be installed within a control house that provides physical security. Other times, relays are installed in breakers or enclosures within the switchyard. The SEL-651R-2 provides tools to help manage physical security, especially when the unit is installed in the switch yard.

You can monitor physical ingress by wiring a door sensor to one of the SEL-651R-2 contact inputs. This input can then be mapped for SCADA monitoring or added to the SER log so that you can monitor when physical access to the relay occurs.

It is also possible to wire an electronic latch to an SEL-651R-2 contact output. You could then map this output for SCADA control.

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Cybersecurity Features M.3
Configuration Management
Wolfe

Configuration Management

Many users are concerned about managing the configuration of their relays. The SEL-651R-2 provides mechanisms to help users manage relay configuration.

All settings changes are logged to the SER log. Analysis of this log indicates if any unauthorized settings changes occurred.

The following Relay Word bits also indicate changes in relay configuration:

➤ SETCHG—Pulses for approximately one second when settings are changed or saved

➤ CHGPASS—Pulses for approximately one second when a password changes

➤ GRPSW—Pulses for approximately one second when the relay switches settings groups

The SEL-651R-2 also stores a hash code for each settings class in the CFG.TXT file. After configuring the device, read the CFG.TXT file and store it for future reference. Periodically read this file from the relay and compare it to the stored reference. If any of the hash codes have changed, then that settings class has been modified.

Firmware Hash Verification

This device supports digitally signed firmware upgrades. SEL uses the SHA-1 secure hash algorithm to compress and digitally sign firmware upgrade files. The signature ensures that the file has been provided by SEL and that its contents have not been altered. When the file is uploaded to the relay, the signature is verified using a public key stored on the relay. If the relay cannot verify the signature, it rejects the file. See *Appendix B: Firmware Upgrade Instructions* for more information on firmware upgrades.

Malware Protection

The SEL-651R-2 has inherent and continuous monitoring for malware. For a full description of this, see selinc.com/mitigating_malware/.

Security Vulnerabilities

If SEL finds a security vulnerability with the SEL-651R-2, it will be disclosed using our standard security notification process. For a full description of this process, see selinc.com/support/security-notifications/.

M.4 | Cybersecurity Features
Settings Erasure

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Settings Erasure

It is often desirable to erase the settings from the relay when it is removed from service. You can completely erase all the configuration settings from the SEL-651R-2 by using this procedure:

Step 1.   Go to Access Level C (see *ACC, BAC, 2AC, and CAL Commands (Go to Access Level 1, B, 2, or C) on page 10.38*).

Step 2.   Execute the **R_S** command.

Step 3.   Allow the relay to restart.

NOTE: Do not erase settings when sending the relay for service at the factory. SEL needs to be able to see how the relay was configured to properly diagnose any problems.

Once this procedure is complete, all internal instances of user settings and passwords will be erased. Do not do this when sending in the relay for service at the factory. SEL needs to see how the relay was configured to properly diagnose many problems.

Glossary

AC Ripple	The peak-to-peak ac component of a signal or waveform. In the station dc battery system, monitoring ac ripple provides an indication of whether the substation battery charger has failed.
ACSELERATOR QuickSet SEL-5030 Software	A Windows-based program that simplifies settings and provides analysis support.
ACSELERATOR Architect SEL-5032 Software	Architect is an add-on to the QuickSet suite that uses the IEC 61850 Substation Configuration Language to configure SEL IEDs.
ACSI	Abstract communications service interface for the IEC 61850 protocol. Defines a set of objects, a set of services to manipulate and access those objects, and a base set of data types describing objects.
Active Settings Group	The settings group that the SEL-651R-2 is presently using from among eight settings groups available in the relay.
Analog Quantities	Variables represented by such fluctuating measurable quantities as temperature, frequency, current, and voltage.
AND Operator	Logical AND. An operator in Boolean SELOGIC control equations that requires fulfillment of conditions on both sides of the operator before the equation is true.
ANSI Standard Device Numbers	A list of standard numbers used to represent electrical protection and control relays. The standard device numbers used in this instruction manual include the following:

25	Synchronism-Check Element
27	Undervoltage Element
50	Overcurrent Element
51	Inverse Time-Overcurrent Element
52	AC Circuit Breaker
59	Overvoltage Element
69	Permissive Control Device (e.g., permit/block circuit breaker closing)
79	Reclosing Relay
81	Frequency Element

These numbers are frequently used within a suffix letter to further designate their application. The suffix letters used in this instruction manual include the following:

P	Phase Element
G	Ground Element
N	Neutral Element
Q	Negative-Sequence (3I2) Element

Apparent Power, S	Complex power expressed in units of volt-amps (VA), kilovolt-amperes (kVA), or megavolt-amperes (MVA). Accounts for both real (P) and reactive (Q) power dissipated in a circuit: $S = P + jQ$. This is power at the fundamental frequency only; no harmonics are included in this quantity.

GL.2 | Glossary
| ASCII–Contact Output

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ASCII	Abbreviation for American Standard Code for Information Interchange. Defines a standard set of text characters. The SEL-651R-2 uses ASCII text characters to communicate, by using front- and rear-panel EIA-232 serial ports on the relay and through virtual serial ports.
ASCII Terminal	A terminal without built-in logic or local processing capability that can only send and receive information.
Assert	To activate. To fulfill the logic or electrical requirements needed to operate a device. To set a logic condition to the true state (logical 1) of that condition. To apply a closed contact to an SEL-651R-2 input. To close a normally open output contact. To open a normally closed output contact.
AT Modem Command Set Dialing String Standard	The command language standard that Hayes Microcomputer Products, Inc. developed to control auto-dial modems from an ASCII terminal (usually EIA-232 connected) or a PC (personal computer) containing software allowing emulation of such a terminal.
Autoconfiguration	The ability to determine relay type, model number, metering capability, port ID, data rate, passwords, relay elements, and other information that an IED (e.g., SEL-2020/2030/2032 Communications Processor) needs to automatically communicate with relays.
Automatic Messages	Messages including status failure and status warning messages that the relay generates at the serial ports and displays automatically on the front-panel LCD.
Automatic Reclose	Automatic closing of a circuit breaker after a breaker trip by a protective relay.
Boolean Logic Statements	Statements consisting of variables that behave according to Boolean logic operators, such as AND, NOT, and OR.
Breaker Auxiliary Contact	An electrical contact associated with a circuit breaker that opens or closes to indicate the breaker position. A Form A breaker auxiliary contact (ANSI Standard Device Number 52A) closes when the breaker is closed and opens when the breaker is open. A Form B breaker auxiliary contact (ANSI Standard Device Number 52B) opens when the breaker is closed and closes when the breaker is open.
Buffered Report	IEC 61850 IEDs can issue buffered reports of internal events (caused by trigger options data-change, quality-change, and data-update). These event reports can be sent immediately or buffered (to some practical limit) for transmission, such that values of data are not lost because of transport flow control constraints or loss of connection. Buffered reporting provides sequence-of-events (SOE) functionality.
C37.118	IEEE C37.118, Standard for Synchrophasors for Power Systems.
CID File	IEC 61850 Configured IED Description file. XML file that contains the configuration for a specific IED.
Common Data Class	IEC 61850 grouping of data objects that model substation functions. Common data classes include status information, controllable status, controllable analog, status settings, analog settings, and description information.
Contact Input	See Control Input.
Contact Output	See Control Output.

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Glossary GL.3
Control Input–Event History

Control Input	Relay input for monitoring the state of external circuits. Connects auxiliary relay and circuit breaker contacts to the control inputs.
Control Output	Relay output that affects the state of other equipment. Connects control outputs to circuit breaker trip and close coils, breaker failure auxiliary relays, communications-assisted tripping circuits, and SCADA systems.
Coordination Timer	A timer that delays an overreaching element so that a downstream device has time to operate.
Counter	Variable or device such as a register or storage location that either records or represents the number of times an event occurs.
Data Class	In the IEC 61850 protocol, an aggregation of classes or data attributes.
Data Object	In the IEC 61850 protocol, part of a logical node representing specific information (status or measurement, for example). From an object-oriented point of view, a data object is an instance of a data class.
Dead Band	The range of variation an analog quantity can traverse before causing a response.
Deassert	To deactivate. To remove the logic or electrical requirements needed to operate a device. To clear a logic condition to its false state (logical 0). To open the circuit or open the contacts across an SEL-651R-2 input. To open a normally open output contact. To close a normally closed output contact.
Debounce Time	The time that masks the period when relay contacts continue to move after closing; debounce time covers this indeterminate state.
Default Data Map	The default map of objects and indices that the SEL-651R-2 uses in DNP protocol.
Demand Meter	A measuring function that calculates a rolling average or thermal average of instantaneous measurements over time.
DNP (Distributed Network Protocol)	Manufacturer-developed, hardware-independent communications protocol.
Dropout Time	The time measured from the removal of an input signal until the output signal deasserts. You can set the time, in the case of a logic variable timer, or the dropout time can be a result of the characteristics of an element algorithm, as in the case of an overcurrent element dropout time.
DTE Devices	Data terminal equipment (computers, terminals, printers, relays, etc.).
EIA-232	Electrical definition for point-to-point serial data communications interfaces, based on the standard EIA/TIA-232. Formerly known as RS-232.
ESD (Electrostatic Discharge)	The sudden transfer of charge between objects at different potentials caused by direct contact or induced by an electrostatic field.
Ethernet	A network physical and data link layer defined by IEE 802.2 and IEEE 802.3.
Event History	A quick look at recent relay activity that includes a standard report header; event number, date, time, and type; fault location; maximum fault phase current; active group at the trigger instant; and targets.

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GL.4 | Glossary
Event Report–IP Address

Event Report	A text-based collection of data stored by the relay in response to a triggering condition, such as a fault or ASCII **TRI** command. The data show relay measurements before and after the trigger, in addition to the states of protection elements, relay inputs, and relay outputs each processing interval. After an electrical system fault, use event reports to analyze relay and system performance.
Event Summary	A shortened version of stored event reports. An event summary includes items such as event date and time, event type, fault location, time source, recloser shot counter, currents, and sequence currents. The relay sends an event report summary (if auto messaging is enabled) to the relay serial port a few seconds after an event.
Fast Meter	SEL binary serial port command used to collect metering data with SEL relays.
Fast Operate	SEL binary serial port command used to perform control with SEL relays.
FET	Field Effect Transistor.
Firmware	The nonvolatile program stored in the relay that defines relay operation.
Flash Memory	A type of nonvolatile relay memory used for storing large blocks of nonvolatile data.
FTP	File Transfer Protocol.
Function Code	A code that defines how you manipulate an object in DNP3 protocol.
Fundamental Frequency	The component of the measured electrical signal with a frequency equal to the normal electrical system frequency, usually 50 Hz or 60 Hz. Generally used to differentiate between the normal system frequency and any harmonic frequencies present.
Global Settings	General settings including those for breaker type, date format, phase rotation, nominal system frequency, enables, control inputs, settings group selection, and current and voltage source selection.
GOOSE	IEC 61850 Generic Object Oriented Substation Event. GOOSE objects can quickly and conveniently transfer status, controls, and measured values among peers on an IEC 61850 network.
GPS	Global Positioning System. Source of position and high-accuracy time information.
GUI	Graphical user interface.
HMI	Human-machine interface.
ICD File	IEC 61850 IED Capability Description file. XML file that describes IED capabilities, including information on logical node and GOOSE support.
IEC 61850	Internationally standard method of communications and integration conceived with the goal of supporting systems of multivendor IEDs networked together to perform protection, monitoring, automation, metering, and control.
IP Address	An identifier for a computer or a device on a TCP/IP network. Networks using the TCP/IP protocol route messages based on the IP address of the destination.

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Glossary GL.5
Local Bits – Peak Demand Metering
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The format of an IP address is a 32-bit numeric address written as four numbers separated by periods. For example, 1.160.10.240 could be an IP address.

Local Bits The Relay Word bit outputs of local control switches that you access through the SEL-651R-2 front panel. Local control switches replace traditional panel mounted control switches.

Lockout Relay An auxiliary relay that prevents operation of associated devices until it is reset either electrically or manually.

Logical 0 A false logic condition, dropped out element, or deasserted control input or control output.

Logical 1 A true logic condition, picked up element, or asserted control input or control output.

Logical Node In IEC 61850, the smallest part of a function that exchanges data. A logical node (LN) is an object defined by its data and methods. Each logical node represents a group of data (controls, status, measurements, etc.) associated with a particular function.

MAC Address The Media Access Control (hardware) address of a device connected to a shared network medium, most often used with Ethernet networks.

Maximum/Minimum Meter Type of meter data presented by the SEL-651R-2 that includes a record of the maximum and minimum of each value, along with the date and time that each maximum and minimum occurred.

Mechanical Operating Time Time between trip initiation or close initiation and the change in status of an associated circuit breaker auxiliary 52A normally open contacts.

MIRRORED BITS Communications Patented relay-to-relay communications protocol that sends internal logic status, encoded in a digital message, from one relay to the other. Eliminates the need for some communications hardware.

MMS Manufacturing Messaging Specification, a data exchange protocol used by UCA.

Nonvolatile Memory Relay memory that persists over time to maintain the contained data even when the relay is de-energized.

NOT Operator A logical operator that produces the inverse value.

OR Operator Logical OR. A Boolean SELOGIC control equation operator that compares two Boolean values and yields either a logical 1 if either compared Boolean value is logical 1 or a logical 0 if both compared Boolean values are logical 0.

Parentheses Operator Math operator. Use paired parentheses to control the execution of operations in a SELOGIC control equation.

PC Personal computer.

Peak Demand Metering Maximum demand and a time stamp for phase currents, negative-sequence and zero-sequence currents, and powers. The SEL-651R-2 stores peak demand values and the date and time these occurred to nonvolatile storage once per day, overwriting the previously stored value if the new value is larger.

GL.6 | Glossary
Phase Rotation–Shot Counter

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Should the relay lose control power, the relay restores the peak demand information saved at 23:50 hours on the previous day.

Phase Rotation

The sequence of voltage or current phasors in a multiphase electrical system. In an ABC phase rotation system, the B-phase voltage lags the A-phase voltage by 120°, and the C-phase voltage lags B-phase voltage by 120°. In an ACB phase rotation system, the C-phase voltage lags the A-phase voltage by 120°, and the B-phase voltage lags the C-phase voltage by 120°.

Phase Selection

Ability of the relay to determine the faulted phase or phases.

R_TRIG

Rising-edge trigger. Boolean SELOGIC control equation operator that triggers an operation upon logic detection of a rising edge.

Relay Word Bit

A single relay element or logic result. A Relay Word bit can equal either logical 1 or logical 0. Logical 1 represents a true logic condition, picked up element, or asserted control input or control output. Logical 0 represents a false logic condition, dropped out element, or deasserted control input or control output. Use Relay Word bits in SELOGIC control equations.

RTU

Remote Terminal Unit.

RXD

Received data.

SCADA

Supervisory control and data acquisition.

SCD File

IEC 61850 Substation Configuration Description file. XML file that contains information on all IEDs within a substation, communications configuration data, and a substation description.

SCL

IEC 61850 Substation Configuration Language. An XML-based configuration language that supports the exchange of database configuration data among different software tools that can be from different manufacturers. There are four types of SCL files used within IEC 61850: CID, ICD, SCD, and SSD.

Self-Test

A function that verifies the correct operation of a critical device subsystem and indicates detection of an out-of-tolerance condition. The SEL-651R-2 has self-tests that validate the relay power supply, microprocessor, memory, and other critical systems.

SELOGIC Control Equation

A relay setting that allows you to control a relay function (such as a control output) using a logical combination of relay element outputs and fixed logic outputs.

SELOGIC Expression Builder

A rules-based editor within the QuickSet software for programming SELOGIC control equations.

Sequential Events Recorder (SER)

A relay function that stores a record of the date and time of each assertion and deassertion of every Relay Word bit in a list that you set in the relay. SER provides a useful way to determine the order and timing of events of a relay operation.

SER

The relay serial port command to request a report of the latest 1000 sequential events.

Shot Counter

A counter that records the number of times a reclosing relay (dev. 79) attempts to close a circuit breaker.

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Glossary GL.7
Single-Phase Trip–Unbuffered Report

Single-Phase Trip	A circuit breaker trip operation that occurs when one pole of the three poles of a circuit breaker opens independently of the other poles.
SSD File	IEC 61850 System Specification Description file. XML file that describes the single-line diagram of the substation and the required logical nodes.
Status Failure	A severe out-of-tolerance internal operating condition. The relay issues a status failure message and enters a protection-disabled state.
Status Warning	Out-of-tolerance internal operating conditions that do not compromise relay protection, yet are beyond expected limits. The relay issues a status warning message and continues to operate.
Subnet Mask	The subnet mask divides the local node IP address into two parts, a network number and a node address on that network. A subnet mask is four bytes of information and is expressed in the same format as an IP address.
Synchronized Phasor	A phasor calculated from data samples using an absolute time signal as the reference for the sampling process. The phasors from remote sites have a defined common phase relationship. Also known as synchrophasor.
Telnet	An Internet protocol for exchanging terminal data that connects a computer to a network server and allows control of that server and communication with other servers on the network.
Three-Phase Trip	A circuit breaker operation that occurs when the circuit breaker opens all three poles at the same time.
Torque Control	A method of using one relay element to supervise the operation of another.
Total Clearing Time	The time interval from the beginning of a fault condition to final interruption of the circuit.
Unbuffered Report	IEC 61850 IEDs can issue immediate unbuffered reports of internal events (caused by trigger options data-change, quality-change, and data-update) on a "best effort" basis. If no association exists, or if the transport data flow is not fast enough to support it, events can be lost.

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SEL-651R-2 Recloser Control
Command Summary

Command	Access Level	Prompt	Command Description
2AC	1	=>	Enter Access Level 2.
ACC	0	=	Enter Access Level 1.
BAC	1	=>	Enter Breaker Access Level (Access Level B).
BNA	0	=	Display names of status bits in the A5D1 Fast Meter Message.
BRE	1	=>	Display breaker/recloser contact wear report.
BRE R	B	==>	Reset breaker/recloser contact wear monitor.
BRE W	B	==>	Preload breaker/recloser contact wear monitor data.
BTT	B	==>	Display latest battery load test results and time remaining until next discharge test.
BTT NOW	B	==>	Force a battery test and view the results.
CAL	2	=>>	Enter Access Level C. Reserved for SEL use only.
CAS	0	=	Display Compressed ASCII configuration message.
CEV *n*	1	=>	Display event report *n* in Compressed ASCII format. Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.
CEV HIF *n*	1	=>	Display HIF event report *n* in Compressed ASCII format. Parameter *n* corresponds to the event number from the **HIS HIF** command.
CHI	1	=>	Display history data in Compressed ASCII format.
CHI HIF	1	=>	Display HIF history data in Compressed ASCII format.
CLO, CLO A, CLO B, CLO C	B	==>	Momentarily assert Relay Word bit CC3, CCA, CCB, or CCC).
COM *c*	1	=>	Show communications summary report (COM report) on MIRRORED BITS Channel *c* (*c* = A or B) using all failure records in the channel calculations.
COM *c row1*	1	=>	Show COM report for MIRRORED BITS Channel *c* using the latest *row1* failure records (*row1* = 1–255, where 1 is the most recent entry).
COM *c row1 row2*	1	=>	Show COM report for MIRRORED BITS Channel *c* using failure records *row1*–*row2* ([*row1* and *row2*] = 1–255).
COM *c date1*	1	=>	Show COM report for MIRRORED BITS Channel *c* using failures recorded on date *date1* (see **DAT** command for date format).
COM *c date1 date2*	1	=>	Show COM report for MIRRORED BITS Channel *c* using failures recorded between dates *date1* and *date2*, inclusive.
COM *c* C	1	=>	Clears communications records for MIRRORED BITS Channel *c* (or both channels if *c* is not specified).
COM *c*… L	1	=>	For all **COM** commands (except **COM *c* C**), **L** causes the specified COM report records to be listed after the summary.
CON *n*	B	==>	Set, clear, or pulse internal Remote Bit *n* (*n* is the Remote Bit number from 01–32). The control will respond with `CONTROL RBn:`. Reply with the following: `SRB` n (to set Remote Bit *n* (assert RB*n*)) `CRB` n (to clear Remote Bit *n* (deassert RB*n*)) `PRB` n (to pulse Remote Bit *n* (assert RB*n* for 1/4 cycle))
COP *m n*	2	=>>	Copy settings from Group *m* to Group *n*.

Command	Access Level	Prompt	Command Description
COP D *m n*	2	=>>	Copy DNP Map *m* to Map *n*.
COU *k*	1	=>	Show the SELOGIC counter values. Enter *k* for repeat count.
CST	1	=>	Display the recloser control status in Compressed ASCII format.
CSU *n*	1	=>	Display the event summary for event report *n* (with label lines) in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.
CSU HIF *n*	1	=>	Display the HIF event summary for event report *n* in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* corresponds to the event number from the **HIS HIF** command.
DAT	1	=>	Display the internal clock date.
DAT *date*	1	=>	Set the internal clock date to *date* (Date Format setting DATE_F = MDY, YMD, or DMY).
DNA X or T	0	=	Display ASCII names of all Relay Word bits digital I/O. Either X or T is mandatory and results are identical.
ETH	1	=>	Displays information about Ethernet port(s).
ETH C	1	=>	Clears Ethernet port sent and received packets, bytes, and error statistics.
EVE *n*	1	=>	Show event report *n* with 4 samples per cycle (*n* = 1 to highest numbered event report, where 1 is the most recent report: see **HIS** command). If *n* is omitted (**EVE** command), the most recent report is displayed.
EVE *n* **A**	1	=>	Show event report *n* with analog section only.
EVE *n* **C**	1	=>	Show event report *n* in Compressed ASCII format with 16 samples-per-cycle analog resolution and 4 samples-per-cycle digital resolution.
EVE *n* **D**	1	=>	Show event report *n* with digital section only.
EVE *n* **L**	1	=>	Show event report *n* with 32 samples per cycle (similar to **EVE** *n* **S32**).
EVE *n* **L***y*	1	=>	Show first *y* cycles of event report *n* (*y* = 1 to Global setting LER).
EVE *n* **M**	1	=>	Show event report *n* with communications section only.
EVE *n* **P**	1	=>	Show event report *n* with synchrophasor-level accuracy time adjustment.
EVE *n* **R**	1	=>	Show event report *n* in raw (unfiltered) format with 32 samples-per-cycle resolution.
EVE *n* **S***x*	1	=>	Show event report *n* with *x* samples per cycle (*x* = 4, 16, 32, or 128). Must append R parameter for S128 (**EVE S128 R**)
EVE *n* **V**	1	=>	Show event report *n* with variable scaling for analog values.
EXI	0	=	Exit active Telnet session.
FIL DIR	1	=>	Display a list of available files.
FIL READ *filename*	1	=>	Transfer settings file or event file *filename* from the relay to the PC.
FIL SHOW *filename*	1	=>	Display contents of the ASCII file *filename*.
FIL WRITE *filename*	2	=>>	Transfer settings file *filename* from the PC to the relay.
GOO	1	=>	Display GOOSE information.
GOO *k*	1	=>	Display GOOSE information *k* times.
GOO S	1	=>	Display a list of GOOSE subscriptions with their ID.
GOO S *n*	1	=>	Display GOOSE statistics for subscription ID *n*.
GOO S *n* **C**	1	=>	Clear GOOSE statistics for subscription ID *n*.
GOO S *n* **L**	1	=>	Display GOOSE statistics for subscription ID *n* including error history.
GOO S ALL	1	=>	Display GOOSE statistics for all subscriptions.

Command	Access Level	Prompt	Command Description
GOO S ALL C	1	=>	Clear GOOSE statistics for all subscriptions.
GOO S ALL L	1	=>	Display GOOSE statistics for all subscriptions including error history.
GRO	1	=>	Display active group number.
GRO *n*	B	==>	Change active group to Group *n* (*n* = 1–8).
HIS	1	=>	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS *n*	1	=>	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list beginning at event *n*.
HIS C	1	=>	Clear/reset the event history and all corresponding event reports from nonvolatile memory.
HIS E	1	=>	Same as **HIS**, but events are identified with a unique number in the range 10000–65535.
HIS HIF	1	=>	Display HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF *n*	1	=>	Display *n* HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF C	1	=>	Clear/reset the HIF event history and all corresponding event reports from nonvolatile memory.
HIZ	1	=>	Display HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.
HIZ *n*	1	=>	Display *n* HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.
HIZ C	1	=>	Clear/reset the HIZ event reports from nonvolatile memory.
ID	0	=	Display the firmware id, user id, device code, part number, and configuration information.
INI HIF	2	=>>	Force HIF algorithm into initial tuning mode.
L_D	2	=>>	Prepares the relay to receive new firmware.
LDP	1	=>	Show entire Load Profile (LDP) report.
LDP *n*	1	=>	Show latest *n* rows in the LDP report (*n* = 1 to several thousand, where 1 is the most recent entry).
LDP *row1 row2*	1	=>	Show rows *row1*–*row2* in the LDP report ([*row1* and *row2*] = 1 to several thousand).
LDP *date1*	1	=>	Show all rows in the LDP report recorded on the specified date *date1* (see **DAT** command for date format).
LDP *date1 date2*	1	=>	Show all rows in the LDP report recorded between dates *date1* and *date2*, inclusive.
LDP C	1	=>	Clears the Load Profile data from memory.
LDP D	1	=>	Display the number of days of Load Profile memory capacity remaining before data over-write occurs.
LOG HIF	1	=>	Display the HIF alarm and fault calculations as a percentage of their final value.
LOG HIF *n*	1	=>	Display the *n* most recent **LOG HIF** entries.
LOG HIF C	1	=>	Clear all **LOG HIF** data from memory.
LOO *c t*	2	=>>	Set MIRRORED BITS Channel *c* to loopback (*c* = A or B). The received MIRRORED BITS elements are forced to default values during the loopback test; *t* specifies the loopback duration in minutes (*t* = 1–5000, default is 5).
LOO *c t* **DATA**	2	=>>	Set MIRRORED BITS Channel *c* to loopback for duration *t* minutes. **DATA** allows the received MIRRORED BITS elements to change during the loopback test.
LOO *c* **R**	2	=>>	Cease loopback on MIRRORED BITS Channel *c* and return the channel to normal operation.
MAC	1	=>	Display Ethernet port MAC address.
MET *k*	1	=>	Display instantaneous metering data *k* times.
MET D	1	=>	Display demand and peak demand metering data.

Command	Access Level	Prompt	Command Description
MET E	1	=>	Display energy metering data.
MET H	1	=>	Display fundamental magnitudes, root-mean-square (rms) magnitudes, Total Harmonic Distortion, and harmonic magnitudes for the first 16 harmonics.
MET HIF *k*	1	=>	Display the HIF alarm and fault calculations as a percentage of their final value. Enter *k* for repeat count ($k = 1$–32767; if not specified, default is 1).
MET M	1	=>	Display maximum and minimum metering data.
MET PM *k*	1	=>	Display synchrophasor measurements (available when TSOK = logical 1). Enter *k* for repeat count.
MET PM *time*	1	=>	Display synchrophasor measurements (available when TSOK = logical 1). Enter *time* to display the synchrophasor for an exact specified time, in 24-hour format.
MET PM HIS	1	=>	Display the most recent MET PM synchrophasor report.
MET RD	1	=>	Reset demand metering data.
MET RE	1	=>	Reset energy metering data.
MET RM	1	=>	Reset maximum metering data. All values will display RESET until new maximum/minimum values are recorded.
MET RMS	1	=>	Display root-mean-square (rms) metering data.
MET RP	1	=>	Reset peak demand metering data.
OPE, OPE A, OPE B, OPE C	B	==>	Momentarily assert Relay Word bit OC3, OCA, OCB, or OCC).
PAR	2	=>>	Change the device part number. Use only under the direction of SEL.
PAS 1	2	=>>	Change the Access Level 1 password.
PAS B	2	=>>	Change the Access Level B password.
PAS 2	2	=>>	Change the Access Level 2 password.
PAS C	C	==>>	Change the Access Level C password.
PUL *n s*	B	==>	Pulse output contact OUT*n* (*n* = 201, 202 [all models]; 101–108 [models with extra I/O]) for *s* (1–30) seconds. Parameter OUT*n* must be specified; *s* defaults to 1 if not specified.
QUI	0	=	Reduce access level to Access Level 0 (exit relay control).
R_S	2	=>>	Restore factory-default settings and passwords. Use only under the direction of SEL. Only available after a settings or critical RAM failure.
SER	1	=>	Show entire Sequential Events Recorder (SER) report.
SER *n*	1	=>	Show latest *n* rows in the SER report (*n* = 1–1024, where 1 is the most recent entry).
SER *row1 row2*	1	=>	Show rows *row1*–*row2* in the SER report.
SER *date1*	1	=>	Show all rows in the SER report recorded on the specified date *date1* (see **DAT** command for date format).
SER *date1 date2*	1	=>	Show all rows in the SER report recorded between dates *date1* and *date2*, inclusive.
SER C	1	=>	Clears SER report from nonvolatile memory.
SET *n*	2	=>>	Change relay settings (overcurrent, reclosing, timers, etc.) for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SET D *n*	2	=>>	Change DNP Map *n* settings (*n* = 1, 2, or 3).
SET F	2	=>>	Change Front-Panel settings.
SET G	2	=>>	Change Global settings.
SET L *n*	2	=>>	Change SELOGIC control equation settings for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SET M	2	=>>	Change Modbus settings.

Command	Access Level	Prompt	Command Description
SET P *p*	2	=>>	Change Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).
SET R	2	=>>	Change SER and LDP Recorder settings.
SET … *name*	2	=>>	For all **SET** commands, jump ahead to specific setting by entering setting name.
SET … TERSE	2	=>>	For all **SET** commands, the **TERSE** command disables the automatic **SHO** command after settings entry.
SHO *n*	1	=>	Show relay settings (overcurrent, reclosing, timers, etc.) for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SHO D *n*	1	=>	Show DNP Map *n* settings (*n* = 1, 2, or 3).
SHO F	1	=>	Show Front-Panel settings.
SHO G	1	=>	Show Global settings.
SHO L *n*	1	=>	Show SELOGIC control equation settings for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SHO M	1	=>	Show Modbus settings.
SHO P *p*	1	=>	Show Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).
SHO R	1	=>	Show SER and LDP Recorder settings.
SHO … *name*	1	=>	For all **SHO** commands, jump ahead to specific setting by entering setting name.
SNS	0	=	Display the Fast Message name string of the SER settings.
SSI	1	=>	Show entire Voltage Sag/Swell/Interruption (SSI) report.
SSI *n*	1	=>	Show latest *n* rows in SSI report (*n* = 1 to several thousand, where 1 is the most recent entry).
SSI *row1 row2*	1	=>	Show rows *row1*–*row2* in SSI report.
SSI *date1*	1	=>	Show all rows in SSI report recorded on the specified date *date1* (see **DAT** command for date format).
SSI *date1 date2*	1	=>	Show all rows in SSI report recorded between dates *date1* and *date2*, inclusive.
SSI C	1	=>	Clears SSI report from nonvolatile memory.
SSI R	1	=>	Reset the VSSI recorder logic and clear the Vbase value.
SSI T	1	=>	Trigger the SSI recorder.
STA *k*	1	=>	Display the recloser control self-test information *k* times (*k* = 1–32767; if not specified, default is 1).
STA C	2	=>>	Clear status warning or failure and reboot the recloser control.
STA S	1	=>	Display the memory and execution utilization for the SELOGIC control equations.
SUM HIF *n*	1	=>	Display the HIF summary message for event *n*.
TAR	1	=>	Display Relay Word 0 or last displayed target row.
TAR *n k*	1	=>	Display Relay Word row number *n*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).
TAR *name k*	1	=>	Display Relay Word row containing *name*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).
TAR LIST	1	=>	Shows all the Relay Word bits in all of the rows.
TAR R	1	=>	Reset front-panel tripping targets.
TAR ROW …	1	=>	Shows the Relay Word row number at the start of each line, with other selected **TAR** commands as described above, such as *n*, **name**, *k*, and **LIST**.
TES DB	B	==>	Display the present status of digital and analog overrides.

Command	Access Level	Prompt	Command Description
TES DB A *name value*	B	==>	Override analog label *name* with *value* in communications interface.
TES DB A *row_x value*	B	==>	Override all Relay Word bits in Relay Word row number *row_x* with *value*.
TES DB D *name value*	B	==>	Override Relay Word bit *name* with *value* in communications interface, where *value* = 0 or 1.
TES DB *name* **OFF**	B	==>	Clear (analog or digital) override for element *name*.
TES DB OFF	B	==>	Clear all analog and digital overrides.
TIM	1	=>	Display the present internal clock time.
TIM *hh:mm*	1	=>	Set the internal clock to *hh:mm*.
TIM *hh:mm:ss*	1	=>	Set the internal clock to *hh:mm:ss*.
TIM Q	1	=>	Display time statistics.
TIM DST	1	=>	Display daylight-saving time information.
TRI	1	=>	Trigger event report data capture.
TRI *time*	1	=>	Trigger an event report data capture at specified *time*.
TRI HIF	1	=>	Trigger an HIF event report data capture. Only available in recloser controls that support Arc Sense technology.
TRI STA	1	=>	Display the status of a previous **TRI** *time* command.
VEC D	2	=>>	Display the standard Vector Report.
VEC E	2	=>>	Display the Extended Vector Report.
VER	1	=>	Display information about the configuration of the recloser control.

Keystroke Commands

Keystroke	Description	Keystroke When Using SET Command	Description
<Ctrl+Q>	Sends **XON** command to restart communications port output previously halted by XOFF.	**<Enter>**	Retains setting and moves on to next setting.
<Ctrl+S>	Sends **XOFF** command to pause communications port output.	**^ <Enter>**	Returns to previous setting.
<Ctrl+X>	Sends **CANCEL** command to abort current command and return to current access level prompt.	**< <Enter>**	Returns to previous setting section.
		> <Enter>	Skips to next setting section.
		END <Enter>	Exits setting editing session, then prompts user to save settings.
		<Ctrl+X>	Aborts setting editing session without saving changes.

SEL-651R-2 Recloser Control
Command Summary

Command	Access Level	Prompt	Command Description
2AC	1	=>	Enter Access Level 2.
ACC	0	=	Enter Access Level 1.
BAC	1	=>	Enter Breaker Access Level (Access Level B).
BNA	0	=	Display names of status bits in the A5D1 Fast Meter Message.
BRE	1	=>	Display breaker/recloser contact wear report.
BRE R	B	==>	Reset breaker/recloser contact wear monitor.
BRE W	B	==>	Preload breaker/recloser contact wear monitor data.
BTT	B	==>	Display latest battery load test results and time remaining until next discharge test.
BTT NOW	B	==>	Force a battery test and view the results.
CAL	2	=>>	Enter Access Level C. Reserved for SEL use only.
CAS	0	=	Display Compressed ASCII configuration message.
CEV n	1	=>	Display event report n in Compressed ASCII format. Parameter n can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.
CEV HIF n	1	=>	Display HIF event report n in Compressed ASCII format. Parameter n corresponds to the event number from the **HIS HIF** command.
CHI	1	=>	Display history data in Compressed ASCII format.
CHI HIF	1	=>	Display HIF history data in Compressed ASCII format.
CLO, CLO A, CLO B, CLO C	B	==>	Momentarily assert Relay Word bit CC3, CCA, CCB, or CCC).
COM c	1	=>	Show communications summary report (COM report) on MIRRORED BITS Channel c (c = A or B) using all failure records in the channel calculations.
COM c $row1$	1	=>	Show COM report for MIRRORED BITS Channel c using the latest $row1$ failure records ($row1$ = 1–255, where 1 is the most recent entry).
COM c $row1$ $row2$	1	=>	Show COM report for MIRRORED BITS Channel c using failure records $row1$–$row2$ ([$row1$ and $row2$] = 1–255).
COM c $date1$	1	=>	Show COM report for MIRRORED BITS Channel c using failures recorded on date $date1$ (see **DAT** command for date format).
COM c $date1$ $date2$	1	=>	Show COM report for MIRRORED BITS Channel c using failures recorded between dates $date1$ and $date2$, inclusive.
COM c **C**	1	=>	Clears communications records for MIRRORED BITS Channel c (or both channels if c is not specified).
COM c… **L**	1	=>	For all **COM** commands (except **COM** c **C**), **L** causes the specified COM report records to be listed after the summary.
CON n	B	==>	Set, clear, or pulse internal Remote Bit n (n is the Remote Bit number from 01–32). The control will respond with `CONTROL RBn:`. Reply with the following: `SRB  n` (to set Remote Bit n (assert RBn)) `CRB  n` (to clear Remote Bit n (deassert RBn)) `PRB  n` (to pulse Remote Bit n (assert RBn for 1/4 cycle))
COP m n	2	=>>	Copy settings from Group m to Group n.

Command	Access Level	Prompt	Command Description
COP D *m n*	2	=>>	Copy DNP Map *m* to Map *n*.
COU *k*	1	=>	Show the SELOGIC counter values. Enter *k* for repeat count.
CST	1	=>	Display the recloser control status in Compressed ASCII format.
CSU *n*	1	=>	Display the event summary for event report *n* (with label lines) in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* can correspond to the number from the **HIS** command or the unique event number from the **HIS E** command.
CSU HIF *n*	1	=>	Display the HIF event summary for event report *n* in Compressed ASCII format. If *n* is omitted, the default is 1 (most recent). Parameter *n* corresponds to the event number from the **HIS HIF** command.
DAT	1	=>	Display the internal clock date.
DAT *date*	1	=>	Set the internal clock date to *date* (Date Format setting DATE_F = MDY, YMD, or DMY).
DNA X or T	0	=	Display ASCII names of all Relay Word bits digital I/O. Either X or T is mandatory and results are identical.
ETH	1	=>	Displays information about Ethernet port(s).
ETH C	1	=>	Clears Ethernet port sent and received packets, bytes, and error statistics.
EVE *n*	1	=>	Show event report *n* with 4 samples per cycle (*n* = 1 to highest numbered event report, where 1 is the most recent report: see **HIS** command). If *n* is omitted (**EVE** command), the most recent report is displayed.
EVE *n* **A**	1	=>	Show event report *n* with analog section only.
EVE *n* **C**	1	=>	Show event report *n* in Compressed ASCII format with 16 samples-per-cycle analog resolution and 4 samples-per-cycle digital resolution.
EVE *n* **D**	1	=>	Show event report *n* with digital section only.
EVE *n* **L**	1	=>	Show event report *n* with 32 samples per cycle (similar to **EVE** *n* **S32**).
EVE *n* **L***y*	1	=>	Show first *y* cycles of event report *n* (*y* = 1 to Global setting LER).
EVE *n* **M**	1	=>	Show event report *n* with communications section only.
EVE *n* **P**	1	=>	Show event report *n* with synchrophasor-level accuracy time adjustment.
EVE *n* **R**	1	=>	Show event report *n* in raw (unfiltered) format with 32 samples-per-cycle resolution.
EVE *n* **S***x*	1	=>	Show event report *n* with *x* samples per cycle (*x* = 4, 16, 32, or 128). Must append R parameter for S128 (**EVE S128 R**)
EVE *n* **V**	1	=>	Show event report *n* with variable scaling for analog values.
EXI	0	=	Exit active Telnet session.
FIL DIR	1	=>	Display a list of available files.
FIL READ *filename*	1	=>	Transfer settings file or event file *filename* from the relay to the PC.
FIL SHOW *filename*	1	=>	Display contents of the ASCII file *filename*.
FIL WRITE *filename*	2	=>>	Transfer settings file *filename* from the PC to the relay.
GOO	1	=>	Display GOOSE information.
GOO *k*	1	=>	Display GOOSE information *k* times.
GOO S	1	=>	Display a list of GOOSE subscriptions with their ID.
GOO S *n*	1	=>	Display GOOSE statistics for subscription ID *n*.
GOO S *n* **C**	1	=>	Clear GOOSE statistics for subscription ID *n*.
GOO S *n* **L**	1	=>	Display GOOSE statistics for subscription ID *n* including error history.
GOO S ALL	1	=>	Display GOOSE statistics for all subscriptions.

Command	Access Level	Prompt	Command Description
GOO S ALL C	1	=>	Clear GOOSE statistics for all subscriptions.
GOO S ALL L	1	=>	Display GOOSE statistics for all subscriptions including error history.
GRO	1	=>	Display active group number.
GRO *n*	B	==>	Change active group to Group *n* (*n* = 1–8).
HIS	1	=>	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS *n*	1	=>	Display event histories with the oldest at the bottom of the list and the most recent at the top of the list beginning at event *n*.
HIS C	1	=>	Clear/reset the event history and all corresponding event reports from nonvolatile memory.
HIS E	1	=>	Same as **HIS**, but events are identified with a unique number in the range 10000–65535.
HIS HIF	1	=>	Display HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF *n*	1	=>	Display *n* HIF event histories with the oldest at the bottom of the list and the most recent at the top of the list.
HIS HIF C	1	=>	Clear/reset the HIF event history and all corresponding event reports from nonvolatile memory.
HIZ	1	=>	Display HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.
HIZ *n*	1	=>	Display *n* HIZ event reports with the oldest at the bottom of the list and the most recent at the top of the list.
HIZ C	1	=>	Clear/reset the HIZ event reports from nonvolatile memory.
ID	0	=	Display the firmware id, user id, device code, part number, and configuration information.
INI HIF	2	=>>	Force HIF algorithm into initial tuning mode.
L_D	2	=>>	Prepares the relay to receive new firmware.
LDP	1	=>	Show entire Load Profile (LDP) report.
LDP *n*	1	=>	Show latest *n* rows in the LDP report (*n* = 1 to several thousand, where 1 is the most recent entry).
LDP *row1 row2*	1	=>	Show rows *row1*–*row2* in the LDP report ([*row1* and *row2*] = 1 to several thousand).
LDP *date1*	1	=>	Show all rows in the LDP report recorded on the specified date *date1* (see **DAT** command for date format).
LDP *date1 date2*	1	=>	Show all rows in the LDP report recorded between dates *date1* and *date2*, inclusive.
LDP C	1	=>	Clears the Load Profile data from memory.
LDP D	1	=>	Display the number of days of Load Profile memory capacity remaining before data over-write occurs.
LOG HIF	1	=>	Display the HIF alarm and fault calculations as a percentage of their final value.
LOG HIF *n*	1	=>	Display the *n* most recent **LOG HIF** entries.
LOG HIF C	1	=>	Clear all **LOG HIF** data from memory.
LOO *c t*	2	=>>	Set MIRRORED BITS Channel *c* to loopback (*c* = A or B). The received MIRRORED BITS elements are forced to default values during the loopback test; *t* specifies the loopback duration in minutes (*t* = 1–5000, default is 5).
LOO *c t* **DATA**	2	=>>	Set MIRRORED BITS Channel *c* to loopback for duration *t* minutes. **DATA** allows the received MIRRORED BITS elements to change during the loopback test.
LOO *c* **R**	2	=>>	Cease loopback on MIRRORED BITS Channel *c* and return the channel to normal operation.
MAC	1	=>	Display Ethernet port MAC address.
MET *k*	1	=>	Display instantaneous metering data *k* times.
MET D	1	=>	Display demand and peak demand metering data.

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Command	Access Level	Prompt	Command Description
MET E	1	=>	Display energy metering data.
MET H	1	=>	Display fundamental magnitudes, root-mean-square (rms) magnitudes, Total Harmonic Distortion, and harmonic magnitudes for the first 16 harmonics.
MET HIF k	1	=>	Display the HIF alarm and fault calculations as a percentage of their final value. Enter k for repeat count (k = 1–32767; if not specified, default is 1).
MET M	1	=>	Display maximum and minimum metering data.
MET PM k	1	=>	Display synchrophasor measurements (available when TSOK = logical 1). Enter k for repeat count.
MET PM $time$	1	=>	Display synchrophasor measurements (available when TSOK = logical 1). Enter $time$ to display the synchrophasor for an exact specified time, in 24-hour format.
MET PM HIS	1	=>	Display the most recent MET PM synchrophasor report.
MET RD	1	=>	Reset demand metering data.
MET RE	1	=>	Reset energy metering data.
MET RM	1	=>	Reset maximum metering data. All values will display RESET until new maximum/minimum values are recorded.
MET RMS	1	=>	Display root-mean-square (rms) metering data.
MET RP	1	=>	Reset peak demand metering data.
OPE, OPE A, OPE B, OPE C	B	==>	Momentarily assert Relay Word bit OC3, OCA, OCB, or OCC).
PAR	2	=>>	Change the device part number. Use only under the direction of SEL.
PAS 1	2	=>>	Change the Access Level 1 password.
PAS B	2	=>>	Change the Access Level B password.
PAS 2	2	=>>	Change the Access Level 2 password.
PAS C	C	==>>	Change the Access Level C password.
PUL n s	B	==>	Pulse output contact OUTn (n = 201, 202 [all models]; 101–108 [models with extra I/O]) for s (1–30) seconds. Parameter OUTn must be specified; s defaults to 1 if not specified.
QUI	0	=	Reduce access level to Access Level 0 (exit relay control).
R_S	2	=>>	Restore factory-default settings and passwords. Use only under the direction of SEL. Only available after a settings or critical RAM failure.
SER	1	=>	Show entire Sequential Events Recorder (SER) report.
SER n	1	=>	Show latest n rows in the SER report (n = 1–1024, where 1 is the most recent entry).
SER $row1$ $row2$	1	=>	Show rows $row1$–$row2$ in the SER report.
SER $date1$	1	=>	Show all rows in the SER report recorded on the specified date $date1$ (see **DAT** command for date format).
SER $date1$ $date2$	1	=>	Show all rows in the SER report recorded between dates $date1$ and $date2$, inclusive.
SER C	1	=>	Clears SER report from nonvolatile memory.
SET n	2	=>>	Change relay settings (overcurrent, reclosing, timers, etc.) for Group n (n = 1–8; if not specified, default is the active settings group).
SET D n	2	=>>	Change DNP Map n settings (n = 1, 2, or 3).
SET F	2	=>>	Change Front-Panel settings.
SET G	2	=>>	Change Global settings.
SET L n	2	=>>	Change SELOGIC control equation settings for Group n (n = 1–8; if not specified, default is the active settings group).
SET M	2	=>>	Change Modbus settings.

Command	Access Level	Prompt	Command Description
SET P *p*	2	=>>	Change Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).
SET R	2	=>>	Change SER and LDP Recorder settings.
SET … *name*	2	=>>	For all **SET** commands, jump ahead to specific setting by entering setting name.
SET … TERSE	2	=>>	For all **SET** commands, the **TERSE** command disables the automatic **SHO** command after settings entry.
SHO *n*	1	=>	Show relay settings (overcurrent, reclosing, timers, etc.) for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SHO D *n*	1	=>	Show DNP Map *n* settings (*n* = 1, 2, or 3).
SHO F	1	=>	Show Front-Panel settings.
SHO G	1	=>	Show Global settings.
SHO L *n*	1	=>	Show SELOGIC control equation settings for Group *n* (*n* = 1–8; if not specified, default is the active settings group).
SHO M	1	=>	Show Modbus settings.
SHO P *p*	1	=>	Show Port settings for Serial Port *p* (*p* = 1, 2, 3, F, or 5; if not specified, default is the active port).
SHO R	1	=>	Show SER and LDP Recorder settings.
SHO … *name*	1	=>	For all **SHO** commands, jump ahead to specific setting by entering setting name.
SNS	0	=	Display the Fast Message name string of the SER settings.
SSI	1	=>	Show entire Voltage Sag/Swell/Interruption (SSI) report.
SSI *n*	1	=>	Show latest *n* rows in SSI report (*n* = 1 to several thousand, where 1 is the most recent entry).
SSI *row1 row2*	1	=>	Show rows *row1–row2* in SSI report.
SSI *date1*	1	=>	Show all rows in SSI report recorded on the specified date *date1* (see **DAT** command for date format).
SSI *date1 date2*	1	=>	Show all rows in SSI report recorded between dates *date1* and *date2*, inclusive.
SSI C	1	=>	Clears SSI report from nonvolatile memory.
SSI R	1	=>	Reset the VSSI recorder logic and clear the Vbase value.
SSI T	1	=>	Trigger the SSI recorder.
STA *k*	1	=>	Display the recloser control self-test information *k* times (*k* = 1–32767; if not specified, default is 1).
STA C	2	=>>	Clear status warning or failure and reboot the recloser control.
STA S	1	=>	Display the memory and execution utilization for the SELOGIC control equations.
SUM HIF *n*	1	=>	Display the HIF summary message for event *n*.
TAR	1	=>	Display Relay Word 0 or last displayed target row.
TAR *n k*	1	=>	Display Relay Word row number *n*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).
TAR *name k*	1	=>	Display Relay Word row containing *name*. Enter *k* for repeat count (*k* = 1–32767; if not specified, default is 1).
TAR LIST	1	=>	Shows all the Relay Word bits in all of the rows.
TAR R	1	=>	Reset front-panel tripping targets.
TAR ROW …	1	=>	Shows the Relay Word row number at the start of each line, with other selected **TAR** commands as described above, such as *n*, *name*, *k*, and **LIST**.
TES DB	B	==>	Display the present status of digital and analog overrides.

Command	Access Level	Prompt	Command Description
TES DB A *name value*	B	==>	Override analog label *name* with *value* in communications interface.
TES DB A *row_x value*	B	==>	Override all Relay Word bits in Relay Word row number *row_x* with *value*.
TES DB D *name value*	B	==>	Override Relay Word bit *name* with *value* in communications interface, where *value* = 0 or 1.
TES DB *name* **OFF**	B	==>	Clear (analog or digital) override for element *name*.
TES DB OFF	B	==>	Clear all analog and digital overrides.
TIM	1	=>	Display the present internal clock time.
TIM *hh:mm*	1	=>	Set the internal clock to *hh:mm*.
TIM *hh:mm:ss*	1	=>	Set the internal clock to *hh:mm:ss*.
TIM Q	1	=>	Display time statistics.
TIM DST	1	=>	Display daylight-saving time information.
TRI	1	=>	Trigger event report data capture.
TRI *time*	1	=>	Trigger an event report data capture at specified *time*.
TRI HIF	1	=>	Trigger an HIF event report data capture. Only available in recloser controls that support Arc Sense technology.
TRI STA	1	=>	Display the status of a previous **TRI** *time* command.
VEC D	2	=>>	Display the standard Vector Report.
VEC E	2	=>>	Display the Extended Vector Report.
VER	1	=>	Display information about the configuration of the recloser control.

Keystroke Commands

Keystroke	Description	Keystroke When Using SET Command	Description
<Ctrl+Q>	Sends **XON** command to restart communications port output previously halted by XOFF.	**<Enter>**	Retains setting and moves on to next setting.
<Ctrl+S>	Sends **XOFF** command to pause communications port output.	**^ <Enter>**	Returns to previous setting.
<Ctrl+X>	Sends **CANCEL** command to abort current command and return to current access level prompt.	**< <Enter>**	Returns to previous setting section.
		> <Enter>	Skips to next setting section.
		END <Enter>	Exits setting editing session, then prompts user to save settings.
		<Ctrl+X>	Aborts setting editing session without saving changes.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 69

Responding Witness: John K. Wolfe

Q-69.   Explain how real-time information gained from SCADA, DSCADA, and ADMS
will be analyzed and centrally managed.

A-69.   ADMS is a common industry term that includes the Outage Management System
(OMS), Distribution Management System (DMS) and distribution SCADA. The
OMS and DMS modules are contained in a single information system, which is
then integrated with the distribution SCADA system. This allows all data to be
analyzed and managed centrally.

The distribution SCADA system will gather and provide data from field devices
such as reclosers and substation devices to the DMS allowing the Distribution
Systems Operator (DSO) to remotely monitor and operate these devices. The DMS
combines the distribution SCADA and outage call data from the OMS and provides
isolation and restoration plans to the DSO. These plans can be automatically
performed to isolate and restore the distribution SCADA devices or can be
manually performed by the DSO. The DMS will also recommend manual steps for
isolation and restoration on manually operated devices when requested by the DSO.

Additionally, the DMS provides real-time operational status of the system to the
DSO who can then coordinate work in the field. The DMS documents and tracks
switch plans and field safety work procedures such as Cautions and Hold cards.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
Dated December 13, 2018**

Case No. 2018-00295

Question No. 70

Responding Witness: Lonnie E. Bellar / John K. Wolfe

Q-70. Provide projected spending levels for the next five (5) years for each of the
following items:

    a. overhead line replacements;

    b. underground line replacements;

    c. breaker replacements;

    d. switch replacements;

    e. substation insulator replacements;

    f. substation arrester replacements;

    g. coupling capacitor replacements

A-70. a-g. The tables below show the costs for each item for distribution and
transmission.

	Electric Distribution				
	2019	2020	2021	2022	2023
Overhead Line Replacements	$4,040,332	$4,212,459	$5,216,000	$4,104,000	$4,312,000
Underground Line Replacements	$17,687,854	$16,238,955	$14,922,027	$3,026,000	$3,117,000
Breaker Replacements	$1,764,900	$1,585,776	$1,711,833	$1,485,000	$1,634,000
Switch Replacements	Not specifically budgeted for in electric distribution				
Substation Insulator Replacements	$163,876	$167,898	$171,926	$177,000	$181,000
Substation Arrester Replacements	$64,999	$67,000	$68,000	$70,000	$72,000
Coupling Capacitor Replacements	Not a device used in electric distribution				

	Transmission				
	2019	2020	2021	2022	2023
Overhead Line Replacements	$10,130,316	$12,741,920	$18,022,162	$11,708,765	$9,739,584
Underground Line Replacements	$0	$0	$0	$0	$0
Breaker Replacements	**	**	**	**	**
Lines Switch Replacements	$155,988	$507,496	$0	$0	$0
Substation Insulator Replacements	**	**	**	**	**
Substation Arrester Replacements	**	**	**	**	**
Coupling Capacitor Replacements	**	**	**	**	**

** This information is not available as the replacement of these items is not planned or budgeted at a specific asset level. Transmission substation asset replacement programs are budgeted at a substation level where multiple asset replacement programs are often bundled into a single substation project. Taking this holistic approach is a more efficient means to replacing targeted assets outlined in the Transmission System Improvement Plan.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 71

Responding Witness: Lonnie E. Bellar

Q-71.   Describe the efforts the Companies are making to engage customers and other potential stakeholders in distribution grid enhancements.

A-71.   LG&E and KU are promoting grid enhancements in a number of owned, earned and paid communications channels, including an animated video, television segments, native content, and digital and social advertising. The Companies have also responded to media inquiries, and promoted grid enhancements in customer newsletters, and on our website and social channels. Internal communications have focused on educating personnel and key contractors on overall and specific grid enhancement efforts to support direct customer and key stakeholder engagements.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 72

Responding Witness: John K. Wolfe

Q-72.   To the extent not already provided, provide all cost benefit analyses performed
since the 2016 rate cases associated with Distribution Automation, preferably in
Excel electronic format, with active cells.

A-72.   See page 13 of the attachment to AG 1-193. Also, see attachments being provided
in Excel format.

The attachments are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 73

Responding Witness: Christopher M. Garrett

Q-73.   The Companies' response to AG DR 1-136(b) states, "See response to PSC 2-62(c)." The response to PSC 2-62(c) provides detail on the composition of the deferred tax balances for the base test year. It does not address the book-tax timing differences that underlie the deferred tax balances in rate base for the forecasted test year. Answer the question as restated below:

   a.   For each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr_Electric, provide the monthly gross book-tax timing differences through April 30, 2020.

   b.   For each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr_Gas, provide the monthly gross book-tax timing differences through April 30, 2020.

   c.   For each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr_Electric, provide the monthly deferred income tax activity through April 30, 2020.

   d.   For each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr_Gas, provide the monthly deferred income tax activity through April 30, 2020.

   e.   For each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr_Electric, provide the monthly accumulated deferred income tax (ADIT) balances through April 30, 2020.

   f.   For each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr_Gas, provide the monthly accumulated deferred income tax (ADIT) balances through April 30, 2020.

   g.   Demonstrate that the aggregate ADIT balances in response to subparts c) and d), above, reconciles to the amount reflected in rate base for test period ending April 30, 2020.

h. Provide the data requested in subparts a) through g), above, in electronic format with formulas intact.

A-73.

a-h.

The information requested is not available. Gross book-tax timing differences are not tracked by book depreciation groups, they are tracked by tax depreciation groups for each year's vintage. It is also not possible to derive that amount by simply applying a tax depreciation rate to the ending depreciable book basis amounts on each line item in Att_[LG&E]_PSC_1-65_Depreciation_Exp_Wkpr. MACRS tax depreciation rates are dependent on an asset's vintage and tax class; therefore the Company calculates forecasted tax depreciation by (1) calculating prior years' vintage tax depreciation on existing assets and (2) calculating tax depreciation on additions during the budget years by applying the appropriate MACRS rate. In the attached excel workbook, the Company has provided a reconciliation of its total tax depreciation calculation for years 2018-2020 to its income tax provision amounts for those same years. For prior years' vintage tax depreciation, the Company provided a report generated from its tax depreciation system by tax class with all vintages combined given the voluminous nature of the data.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 74

Responding Witness: Daniel K. Arbough

Q-74.   Reference the Company's response to Staff DR 2-75 and Attachment Q75d
Schedule A. Explain why short-term debt shown on Schedule J-1 in the Company
calculation of the impact of slippage on LG&E revenue requirements for the
forecasted test year ($87,630,999) is different from the amount included in the
Company's application Schedule J-1 ($97,017,186).

A-74.   The short-term debt shown on Schedule J-1 in response to PSC 2-75 is lower than
the filed Schedule J-1 due to the application of the capital slippage factor and the
resulting reduction of capital spend for the forecasted test period. The reduction
of capital spend in the forecasted period reduces the Company's need to issue
short-term debt to finance the capital expenditures.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 75

Responding Witness: Daniel K. Arbough

Q-75.   Reference the response to AG DR 1-34 (b), attachment. Provide details, including the amount to be spent during the test period, as to the following proposed capital spending projects. If a description for the projects is already included in the application or elsewhere in the record of this case, identify precisely where in the record it can be found:

a. 00066FACL BOC DCC SPACE CONVERSION LGE

b. 00076FACL Building Façade Repairs

c. 119902 Clear 12/04 A&G

d. 134898 PE Vehicle Purchases

e. 138032 IMPROVE PIPELINES

f. 141004 ST HELEN FACILITY

g. 144531 CR7 Misc Project (multi-year)

h. 144869 PRESTON CITY GATE STAT

i. 147831 Corporate Contingency-LGE

j. 152224 Clifty Creek DL1/DL2 Brkr Rpl

k. 152778 LGE FACILITY IMPROVEMENTS-2019

l. 156485 CANAL DEMOLITION

m. 157552 Adams Street Redevelopment

n. 157892 Smart Cities LG&E 2019

o. 157894 EE Business Dvlp LG&E 2019

p. 157897 EE Business Dvlp LG&E 2020

q. 448000011 Magnolia Paving

r. CEMTR134 LGE Electric Meters – 001340

s. CGMTR134 LGE Gas Meters – 001340

t. CRELD340 Capital Reliability – 003400

u. IT0528L LifeIns&Retire Frms/Prtl-LGE19

A-75.   See response to AG 1-34(b) for test year amounts. See attached for a-u.

	Project	Description	Detailed Description	Prior Reference in Case
a	00066FACL	BOC DCC SPACE CONVERSION LGE	Convert vacated Distribution Control Center space in Broadway Office Complex to swing space	
b	00076FACL	Building Façade Repairs	Façade repairs Broadway Office Complex	
c	119902	Clear 12/04 A&G	Capitalized Pension True-up	
d	134898	PE Vehicle Purchases	Purchase of off-road vehicles to be used by Project Engineering while supervising the field work associated with construction and demolition projects.	
e	138032	IMPROVE PIPELINES	General project for budgeting; funding source for improvements to defects discovered during in line inspections of gas transmission lines	
f	141004	ST HELEN FACILITY	Complete upgrades to St. Helen's gas regulating station	
g	144531	CR7 Misc Project (multi-year)	Aggregation of smaller capital expenditures that become necessary due to emergent equipment, operations, and maintenance activities associated with the Cane Run 7 NGCC (Natural Gas Combined Cycle) plant. These expected but unidentified costs are budgeted via miscellaneous projects that are then tracked through a year to fund these types of expected but unidentified needs as they occur.	
h	144869	PRESTON CITY GATE STAT	Rebuild city gate station on Preston Highway	
i	147831	Corporate Contingency-LGE	KY Tax Reform Sales Tax Estimates	AG DR 2-80
j	152224	Clifty Creek DL1/DL2 Brkr Rpl	Replace the existing 345kV DL1 and DL2 circuit breakers	
k	152778	LGE FACILITY IMPROVEMENTS-2019	General project for budgeting; funding source for specific Facilities projects identified throughout the year	
l	156485	CANAL DEMOLITION	This project is for demolition of the Canal generating facility retired in 1966. This amount includes engineering and commercial activities associated with the demolition	KIUC DR 1 LGE 35a
m	157552	Adams Street Redevelopment	New business redevelopment of east downtown Louisville along Adams Street.	
n	157892	Smart Cities LG&E 2019	Lighting and other projects requested as part of the City of Louisville Challenge Grant workshops in support of "Smart City" projects.	
o	157894	EE Business Dvlp LG&E 2019	Distributed Energy Resource (DER) projects	
p	157897	EE Business Dvlp LG&E 2020	Distributed Energy Resource (DER) projects	
q	448000011	Magnolia Paving	Paving work at the Magnolia gas storage facility	
r	CEMTR134	LGE Electric Meters - 001340	Electric meters, transformers, and labor associated with installation of electric meters and transformers, including maintaining adequate stock for the sample meter program.	
s	CGMTR134	LGE Gas Meters - 001340	Gas meters and labor associated with installation of gas meters, including maintaining adequate stock for the sample meter program.	
t	CRELD340	Capital Reliability - 003400	Capital blanket for reliability projects throughout the LGE Electric Distribution Territory	
u	IT0528L	LifeIns&Retire Frms/Prtl-LGE19	Convert hardcopy forms to PeopleSoft system forms	

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 76

Responding Witness: Lonnie E. Bellar

Q-76.   If not already provided, provide the most recent LG&E annual gas system plan.

A-76.   See attachment to Filing Requirements 807 KAR 5:001 Section 16(7)(c) – Attachment to Tab 16 – Item I, page 50 – 73.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 77

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-77.   Reference the responses to AG DR 1-198 and AG DR 1-55.

a. Describe how frequently the Enhanced ILI inspections will be mandated under the new proposed regulation.

b. Confirm that Enhanced ILI inspections could still be conducted even without replacing the 13.2 miles of the Western Kentucky A and B transmission lines.

c. With regard to the Company's response to subpart (b) of AG DR 1-198:

(i) Describe the Enhanced ILI tools that can only collect data for a single diameter size.

(ii) Describe the temporary facilities that would have to be constructed. Provide also a cost estimate for such construction.

(iii) Could the temporary facilities be used again for any other mandated inspections? If not, explain fully why not.

d. Are all of the 13.2 miles of pipeline segments LG&E proposes to replace contiguous?

e. Provide a cost estimate for an Enhanced ILI inspection based on: (i) the pipelines in their current state; and (ii) the assumption that the proposed replacements will be made.

f. State whether there are any other transportation or distribution lines in the LG&E system that require a similar Enhanced ILI inspection, and which are composed of differently-sized pipe diameters. If so, provide a complete description.

(i) Is the Company aware of any other LDCs facing the same issues with regard to pipelines composed of segments having different diameters?

Discuss in detail, and provide any AGA guidance, recommendations or studies regarding this issue.

g. If the Commission should approve this project, state whether it would be more cost-effective to ratepayers if the project's costs were to be recovered via the Gas Line Tracking mechanism, or in base rates.

A-77.

a. Existing regulations (§192.939) require pipeline operators to conduct a form of assessment once every seven years. The proposed regulation does not establish a defined interval to repeat the Enhanced ILIs. However, the proposed regulation establishes a new standard for evaluating pipelines which the Enhanced ILI inspections will be a part of satisfying and LG&E expects to follow the new standard during the required reoccurring seven year assessments.

b. LG&E believes the Enhanced ILI inspections could still be performed, but at a much higher cost and as previously stated in AG 1-55.

c.

(i) Both the Circumferential Magnetic Flux Leakage (MFL-C) tool and Electro Magnetic Acoustic Transducer (EMAT) tool are unable to collect data on the entire length of a pipeline which has both 16-inch and 20-inch pipe in it. The Axial Magnetic Flux Leakage (MFL-A) tool, pipe grade sensors, MFL-C tool, and EMAT tool are unable to collect data the entire length of a pipeline which has 16-inch, 20-inch and 22-inch pipe in it.

(ii) The temporary facilities would be constructed of elbows, tees, valves, pipe, and ILI tool traps. It would cost $5.8M to fabricate, install, and remove the temporary facilities at over 20 locations. This assumes the temporary piping fabrications and ILI tool traps are reused at various sites. It also includes $937K to replace 507-feet of pipe spread across three locations to eliminate six sets of tool runs. The eliminated tool runs would cost more than the replacements. In addition to these construction costs for temporary piping, the cost to run the tools would be much higher as discussed in the response to question Q-77(e) below.

(iii) The majority of the cost is installing and removing the temporary facilities. About $508K in fabricated components and ILI tool traps could possibly be reused in other locations if a need arose. LG&E has not identified any such projects which would require the use of those facilities.

d. No. They are not contiguous sections.

e. In their current state, it would cost $72M to perform Enhanced ILIs of the Western Kentucky A and Western Kentucky B pipelines if no replacements were completed. If the 507-feet of pipe were replaced as discussed in the response to question Q-77 c(ii) above, it would cost $58M to perform the Enhanced ILIs. If the proposed 13.2 miles of replacements are made, it would cost $8.8M to perform the Enhanced ILIs the first time and $5M ($2.5M per pipeline) for the subsequent times. It will cost more the first time because the MFL-A tools are due to be run in the Western Kentucky A pipeline in 2019 and in the Western Kentucky B pipeline in 2020 seven calendar years after each pipeline's last integrity assessment and prior to the pipeline replacements being completed. The EMAT and MFL-C tools would be run after the pipeline replacements are completed. Findings from the Enhanced ILIs may result in the replacement of pipe. Therefore all replacement costs may not be avoided by leaving the pipelines in their current state and spending more money up front to perform Enhanced ILIs on shorter segments.

f. In addition to the pipelines discussed in AG DR 1-198 and AG DR 1-55, the Blanton to Paddy's pipeline is composed of differently sized pipe diameters and will require a similar Enhanced ILI inspection. The Blanton to Paddy's pipeline is 7.3 miles long and made of a 2.7 mile contiguous 20-inch section connected to a 4.6 mile contiguous 16-inch section.
    (i)   LG&E is not familiar with the systems of other LDCs. LG&E is not aware of any AGA guidance, recommendations or studies regarding the issue.

g. The criterion of cost-effectiveness does not apply to the method of recovery. For a summary of how LG&E determines whether costs for a particular project should be recovered through the GLT mechanism or in base rates, see the response to Question No. 78.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 78

Responding Witness: Lonnie E. Bellar

Q-78.   Reference the Company's response to Louisville Metro- 1-90. What makes the $120 million in gas capital expenditures different from what is allowed recovery through the GLT?

A-78.   The $120 million figure referenced in response to Louisville Metro 1-90 is the total non-mechanism gas capital expenditure for the period from January 1, 2018 through October 31, 2019. As summarized on pp. 66 and 67 of Mr. Bellar's testimony, this amount includes capital costs to connect new gas customers, capital investment required to maintain and repair the gas network, and capital cost of certain projects that are not included in the Gas Line Tracker ("GLT") mechanism, including installation of new gas pipeline in Bullitt County and an East End Reinforcement project. These non-GLT capital projects are described in Mr. Bellar's testimony. LG&E seeks recover the costs for these capital investment through base rates.

Conversely, capital expenditures for projects included in the GLT are recovered through a separate line item on customer bills and are not included in base rates. Projects with an established GLT mechanism include replacement of customer gas service lines and gas risers, replacements to modernize gas transmission lines, and a program to replacing aging gas mains. Each of these projects has been approved by the PSC for inclusion in the GLT mechanism.

The decision on whether to include a specific project in a GLT mechanism or to seek recovery in base rates depends on the nature of each project. In general, recovery through the GLT allows LG&E to act more nimbly in response to high priority safety concerns and regulatory changes, without seeking significant upfront capital recovery for these projects through base rates. The inclusion of the gas riser replacement program in the GLT mechanism is one such example.[11]

_____

[11] *See* Case No. 2012-00222, *In the Matter of: Application Of Louisville Gas And Electric Company For An Adjustment Of Its Electric And Gas Rates, A Certificate Of Public Convenience And Necessity, Approval Of Ownership Of Gas Service Lines And Risers, And A Gas Line Surcharge.*

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 79

Responding Witness: Christopher M. Garrett

Q-79.   Reference the Company's response to AG DR 1-85.

a. If the actual history of bad debt is different as shown on PSC-LGE 1-49, explain why the LG&E gas (0.18%) and electric (0.18%) bad debt expense used on Schedule H-1 is the same.

b. Provide the Retail Revenues and Net Charge Offs and Net Charge Off's percent broken down between electric and gas for 2013–2017.

A-79.

a. The difference between the electric and gas net charge-off percentage in PSC 1-49 is the result of the removal of the Gas Supply Clause (GSC) bad debt expense. For example, the GSC bad debt provision for 2017 is $225K which increases the gas bad debt percentage by 0.07% to align with the electric net charge-off percentage.

The Company does not maintain a separate account balance for electric and gas uncollectible accounts, because LG&E customers receive one bill regardless of whether or not they receive gas service. Therefore, the Company used the same net charge-off percentage for electric and gas when developing the revenue requirements.

b. For purposes of responding to this question, the Company has performed an allocation similar to the one used in PSC 1-49 to derive the electric and gas net charge-off percentage split based on revenues.

LG&E Total Company Summary

Year	Retail Revenues	Net Charge Offs	Net Charge Off %
2013	1,314,194,010	1,863,407	0.142%
2014	1,403,783,006	3,623,462	0.258%
2015	1,395,053,719	2,698,427	0.193%
2016	1,373,169,377	2,083,763	0.152%
2017	1,377,548,223	2,271,999	0.165%
5-YR Avg			0.182%

LG&E Electric Summary

Year	Retail Revenues	Net Charge Offs	Net Charge Off %
2013	1,003,167,539	1,640,284	0.164%
2014	1,047,607,991	3,197,686	0.305%
2015	1,079,677,731	2,452,508	0.227%
2016	1,095,756,004	1,823,622	0.166%
2017	1,076,596,028	1,937,028	0.180%
5-YR Avg			0.208%

LG&E Gas Summary

Year	Retail Revenues	Net Charge Offs	Net Charge Off %
2013	311,026,471	223,123	0.072%
2014	356,175,015	425,776	0.120%
2015	315,375,988	245,919	0.078%
2016	277,413,373	260,141	0.094%
2017	300,952,195	334,971	0.111%
5-YR Avg			0.095%

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Supplemental Data Requests for Information
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Case No. 2018-00295

Question No. 80

Responding Witness: Daniel K. Arbough

Q-80.   Reference the Companies' response to Staff DR 1-17 and Attachment 1. Why are the following considered Construction projects?
a.

i)   April 30, 2020

(1) Line 7—Project number 151231 (page 1 of 11) EDO Contingency $1,000

(2) Line 115—Project number IT0000L IT Contingency-LGE (page 2 of 11) $1,649,734.89

(3) Line 187—Project number 147831 Corporate Contingency-LGE (page 3 of 11) $2,745,049.99

ii) December 31, 2018

(1) Line 1—Project number 122457 EDO ADJUSTMENTS (page 4 of 11) $131,000.00

(2) Line 7—Project number 151231 EDO Contingency (page 4 of 11) $1,000.00

(3) Line 91—Project IT0000L IT Contingency-LGE (page 5 of 11) $1,649,734.89

 b. Gas:

i)   April 30, 2020

(1) Line 118 - Project number 147831 Corporate Contingency-LGE (page 2 of 7) $1,233,283.33

ii) December 31, 2018

(1) Line 38 - Project number 147831 Corporate Contingency-LGE (page 3 of 7) $336,350.00

A-80.   The projects shown on this list, with 147831 as the only exception, reflect capital expenditures solely during the base period. Throughout each month in 2018 when the monthly forecast is completed, the lines of business hold funds in these projects to fund projects still under review, which still need to be fully vetted before being entered into the system as a capital project. The description on these projects would be more accurately depicted as "funding for projects under review".

Project 147831 was used this budget season for a last minute change due to Kentucky sales tax reform. This amount will be appropriately allocated across other capital projects through the burden process during the year.