COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

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

FILED: NOVEMBER 29, 2018

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

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of November 2018.

Judy Schooler

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

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of November 2018.

Judy Schooler

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, **Kent W. Blake**, being duly sworn, deposes and says that he is Chief Financial Officer 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.

KWBlake

Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of November 2018.

Judy Schooler

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 29th day of November 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

Christopher M. Garrett

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

Judy Schooler

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

Elizabeth J. McFarland

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of November 2018.

Kimberly C. Bratt

Notary Public

My Commission Expires:

10-16-2020

VERIFICATION

STATE OF TEXAS)
) **SS:**
COUNTY OF TRAVIS)

The undersigned, **Adrien M. McKenzie**, being duly sworn, deposes and says he is President of FINCAP, Inc., 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.

Adrien M. McKenzie

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of November 2018.

Notary Public (SEAL)

My Commission Expires:

04/17/2019

ROBERT LEE MARTINEZ
NOTARY PUBLIC STATE OF TEXAS
MY COMM. EXP. 4/17/2019
NOTARY ID 13019391-2

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

Gregory J. Meiman

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of November 2018.

Judy Schooler

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, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal of The Prime Group, LLC, 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.

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of November 2018.

(SEAL)
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, **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
David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 29th day of November 2018.

Judy Schooler
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.

JK Wolfe

John K. Wolfe

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

Judy Schooler

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 Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 1

Responding Witness: Robert M. Conroy

I. AFFORDABILITY

Q-1. Refer to the direct testimony of Robert M. Conroy, pages 7-8, wherein he states that the "Companies work every day to provide safe, reliable, and economical utility service to our customers," and he discusses the Companies' understanding "of the needs of low- and fixed income customers."

a. Do the Companies consider customer affordability in their operations?

b. Does the Company consider the interest of low- and fixed-income customers to be unique, in that they perceive the costs and service of utilities, in particular their affordability, differently than other customers?

A-1.

a. The Companies strive to provide safe and reliable service at the lowest reasonable cost. This results in service that is as affordable as the Companies can reasonably provide consistent with ensuring safety and reliability.

b. The Companies understand that low- and fixed-income customers face challenges other customers ordinarily do not due to financial constraints; however, those customers' financial constraints do not affect their cost of service. Therefore, the Companies do not consider them to be unique for base-rate purposes.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 2

Responding Witness: Kent W. Blake

Q-2. Refer to the direct testimony of Kent W. Blake, page 12, and the Exhibit KWB-1 to his testimony.

a. Provide the data used to conduct the "benchmarking study."

b. Provide the annual "benchmarking study" conducted by the Companies "for the past fifteen years."

c. Provide the names of each vertically-integrated utility holding companies used in the "benchmarking stud[ies]."

A-2.

a. See attached.

b. See attached.

c. See attached.

Total O&M Rankings [2013-2017]

Vertically-Integrated Utilities

Holding Company	Non Fuel O&M	Transmission O&M	Distribution O&M	CA O&M	CS&I O&M	Sales O&M	A&G O&M	Total O&M	Total Sales of Electricity Volume (MWh)	Total O&M/MWh	Ranking
NextEra Energy, Inc.	3,211,914,000	470,208,000	2,527,266,000	564,942,000	500,604,000	24,482,000	1,887,794,000	9,187,210,000	576,861,659	15.93	1
Entergy Corporation	4,481,460,000	934,816,000	1,222,166,000	681,360,000	472,990,000	29,855,000	3,452,506,000	11,275,153,000	694,118,461	16.24	2
Berkshire Hathaway Inc.	3,806,398,000	1,680,844,000	1,725,328,000	817,844,000	1,390,145,000	23,904,000	1,836,625,000	11,281,088,000	647,595,062	17.42	3
AEP	4,346,465,000	2,427,232,000	2,062,824,000	492,903,000	440,892,000	3,832,000	1,845,863,000	11,620,011,000	626,706,971	18.54	4
OGE Energy Corp.	611,706,000	702,763,000	411,823,000	108,700,000	208,136,000	28,493,000	642,314,000	2,713,935,000	145,554,088	18.65	5
ALLETE, Inc.	379,907,000	367,091,000	123,996,000	29,271,000	49,317,000	869,000	370,989,000	1,321,440,000	70,416,113	18.77	6
Dominion Energy, Inc.	4,448,916,000	255,160,000	971,051,000	439,980,000	175,490,000	88,000	1,796,341,000	8,087,026,000	424,814,207	19.04	7
Avista Corporation	305,503,000	158,299,000	179,854,000	83,892,000	129,760,000	7,000	373,418,000	1,230,733,000	63,822,212	19.28	8
LKE	1,313,419,952	230,632,774	526,284,289	222,919,810	178,486,000	4,703,000	947,428,653	3,423,874,478	177,006,629	19.34	9
Cleco Partners LP	421,371,000	152,471,000	149,310,000	62,686,000	37,608,000	24,297,000	282,366,000	1,130,109,000	58,299,323	19.38	10
Duke Energy Corporation	11,109,825,000	1,109,606,000	3,241,633,000	1,136,576,000	711,452,000	100,217,000	6,218,803,000	23,628,112,000	1,150,359,630	20.54	11
Southern Company	7,964,463,000	1,160,075,000	2,747,952,000	1,411,466,000	828,270,000	345,608,000	5,066,654,000	19,524,488,000	915,739,927	21.32	12
Emera Incorporated	705,275,000	71,304,000	251,064,000	151,846,000	217,513,000	4,034,000	643,530,000	2,044,566,000	95,412,160	21.43	13
SCANA Corporation	940,384,000	99,091,000	264,964,000	237,883,000	59,843,000	7,910,000	857,595,000	2,467,670,000	115,124,628	21.43	14
Ameren Corporation	1,563,045,000	366,156,000	754,189,000	225,560,000	382,491,000	2,120,000	1,281,061,000	4,574,622,000	211,841,552	21.59	15
NorthWestern Corporation	216,273,000	159,692,000	241,548,000	59,911,000	32,141,000	2,767,000	367,391,000	1,079,723,000	48,516,397	22.25	16
Puget Holdings LLC	597,583,000	647,511,000	406,914,000	257,578,000	577,763,000	2,356,000	577,363,000	3,067,068,000	132,788,263	23.10	17
FirstEnergy Corp.	465,917,000	684,771,000	293,703,000	86,381,000	19,737,000	157,000	290,358,000	1,841,024,000	79,273,321	23.22	18
IDACORP, Inc.	445,822,000	131,826,000	242,318,000	111,820,000	208,459,000	80,000	736,901,000	1,877,226,000	80,222,328	23.40	19
AES Corporation	716,088,000	101,951,000	198,321,000	105,520,000	9,346,000	0	656,947,000	1,788,173,000	74,493,278	24.00	20
Xcel Energy Inc.	4,174,691,000	2,883,666,000	1,356,048,000	592,390,000	1,215,984,000	4,203,000	2,876,260,000	13,103,242,000	541,441,613	24.20	21
Great Plains Energy Inc	1,156,321,000	535,891,000	433,341,000	160,502,000	302,006,000	3,646,000	1,198,543,000	3,790,250,000	149,872,607	25.29	22
Iberdrola, S.A.	31,405,000	285,277,000	1,075,191,000	459,155,000	650,390,000	54,713,000	794,002,000	3,350,133,000	128,679,853	26.03	23
Otter Tail Corporation	152,855,000	133,895,000	83,277,000	64,959,000	45,164,000	2,113,000	213,607,000	695,870,000	26,396,332	26.36	24
Portland General Electric Co	598,491,000	482,870,000	531,921,000	270,282,000	72,413,000	0	858,523,000	2,814,500,000	105,742,391	26.62	25
El Paso Electric Company	591,344,000	95,162,000	111,835,000	94,772,000	1,040,000	0	597,214,000	1,491,367,000	54,312,529	27.46	26
Vectren Corporation	353,827,000	86,135,000	77,943,000	30,806,000	2,703,000	53,341,000	198,134,000	802,889,000	28,861,057	27.82	27
Black Hills Corporation	135,065,000	206,278,000	69,185,000	20,206,000	10,072,000	97,000	182,317,000	623,220,000	22,368,133	27.86	28
Pinnacle West Capital Corp	2,113,421,000	399,387,000	498,192,000	270,894,000	306,326,000	56,863,000	943,750,000	4,588,833,000	161,506,003	28.41	29
MDU Resources Group, Inc.	145,977,000	109,043,000	77,742,000	21,613,000	1,270,000	677,000	114,074,000	470,396,000	16,493,138	28.52	30
Algonquin Power & Utilities	177,653,000	110,796,000	138,293,000	44,877,000	15,512,000	1,036,000	238,792,000	726,959,000	25,484,116	28.53	31
Westar Energy, Inc.	1,195,964,000	1,232,092,000	452,871,000	150,871,000	18,014,000	2,000	1,038,532,000	4,088,346,000	142,855,162	28.62	32
NiSource Inc.	968,035,000	187,120,000	226,592,000	93,272,000	2,734,000	5,524,000	1,040,189,000	2,523,466,000	85,969,484	29.35	33
Edison International	1,479,776,000	1,321,030,000	2,501,196,000	864,759,000	2,819,813,000	49,144,000	5,388,228,000	14,423,946,000	476,972,294	30.24	34
PNM Resources, Inc.	826,195,000	186,004,000	109,355,000	75,588,000	4,093,000	23,389,000	707,960,000	1,932,584,000	60,114,213	32.15	35
Sempra Energy	581,673,000	437,267,000	667,850,000	233,627,000	862,008,000	0	2,500,440,000	5,282,865,000	155,746,232	33.92	36
Fortis Inc.	975,583,000	252,060,000	373,224,000	206,686,000	320,902,000	685,000	957,836,000	3,086,976,000	90,696,008	34.04	37
Eversource Energy	239,201,000	209,874,000	321,702,000	154,097,000	84,786,000	117,000	475,987,000	1,485,764,000	42,661,053	34.83	38
PG&E Corporation	3,173,220,000	1,354,096,000	3,793,462,000	1,116,120,000	2,986,920,000	30,751,000	5,557,300,000	18,011,869,000	437,736,683	41.15	39

Total O&M Rankings [2013-2017]

Vertically-Integrated Utilities

Holding Company	Non Fuel O&M	Transmission O&M	Distribution O&M	CA O&M	CS&I O&M	Sales O&M	A&G O&M	Total O&M	Total Sales of Electricity Volume (MWh)	Total O&M/MWh	Ranking
Caisse de dépôt et	81,060,000	472,684,000	171,615,000	39,645,000	14,653,000	253,000	222,644,000	1,002,554,000	23,640,213	42.41	40
Consolidated Edison, Inc.	738,019,000	769,127,000	2,552,659,000	1,092,784,000	1,814,871,000	9,641,000	4,368,342,000	11,345,443,000	234,736,999	48.33	41
Grand Total	67,941,510,952	23,661,253,774	34,166,002,289	13,346,943,810	18,182,117,000	901,974,000	60,604,921,653	218,804,723,478	9,401,252,322		

Q1	20.54
Q2	24.20
Q3	28.53
Industry Avg.	23.27

Notes: Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.
Represents only Vertically-Integrated Utilities

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Total Trans. O&M Expense ($000)	Total Distrib. O&M Expense ($000)	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Indianapolis Power & Light Company	AES Corporation	135,886	11,831	36,907	20,099	2,227	0	139,732	16,033,922
2014Y	Indianapolis Power & Light Company	AES Corporation	132,103	11,608	37,733	21,399	1,963	0	125,982	16,391,321
2015Y	Indianapolis Power & Light Company	AES Corporation	154,809	10,254	39,364	21,360	1,590	0	127,068	14,397,561
2016Y	Indianapolis Power & Light Company	AES Corporation	149,247	27,979	41,074	20,773	1,661	0	133,658	14,185,985
2017Y	Indianapolis Power & Light Company	AES Corporation	144,043	40,279	43,243	21,889	1,905	0	130,507	13,484,489
2013Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	29,656	17,333	26,783	10,067	2,209	349	44,700	5,620,276
2014Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	32,415	22,681	30,603	9,770	2,910	180	45,640	5,131,750
2015Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	37,811	23,667	29,023	8,624	2,986	195	46,209	4,940,028
2016Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	37,151	22,089	26,993	8,062	3,371	154	49,080	4,950,707
2017Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	40,620	25,026	24,891	8,354	4,036	158	53,163	4,841,355
2013Y	ALLETE (Minnesota Power)	ALLETE, Inc.	81,069	52,185	22,181	5,824	13,459	217	69,292	13,264,062
2014Y	ALLETE (Minnesota Power)	ALLETE, Inc.	80,954	64,818	24,612	5,600	11,771	143	80,821	13,942,499
2015Y	ALLETE (Minnesota Power)	ALLETE, Inc.	78,932	73,534	24,187	5,473	8,402	127	73,416	14,369,559
2016Y	ALLETE (Minnesota Power)	ALLETE, Inc.	72,982	84,273	27,423	5,802	4,018	163	60,228	14,147,335
2017Y	ALLETE (Minnesota Power)	ALLETE, Inc.	65,970	92,281	25,593	6,572	11,667	219	87,232	14,692,658
2013Y	Union Electric Company	Ameren Corporation	309,718	58,896	167,177	38,686	57,800	447	251,904	43,158,138
2014Y	Union Electric Company	Ameren Corporation	315,539	60,321	160,869	39,791	66,225	463	278,701	43,192,724
2015Y	Union Electric Company	Ameren Corporation	347,345	70,144	149,481	50,894	97,842	458	264,623	43,255,846
2016Y	Union Electric Company	Ameren Corporation	296,877	80,459	136,774	49,258	72,182	364	251,783	39,997,209
2017Y	Union Electric Company	Ameren Corporation	293,566	96,336	139,888	46,931	88,442	388	234,050	42,237,635
2013Y	Appalachian Power Company	American Electric Power Company, Inc.	194,328	76,711	168,579	35,569	6,965	155	104,512	47,596,529
2014Y	Appalachian Power Company	American Electric Power Company, Inc.	252,109	141,646	123,923	40,890	8,717	297	111,163	35,769,358
2015Y	Appalachian Power Company	American Electric Power Company, Inc.	226,788	143,949	139,749	37,672	11,144	264	104,606	34,847,578
2016Y	Appalachian Power Company	American Electric Power Company, Inc.	219,726	216,840	158,709	37,801	16,466	213	104,282	34,862,820
2017Y	Appalachian Power Company	American Electric Power Company, Inc.	211,709	232,090	148,298	39,807	17,920	275	101,376	33,601,395
2013Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	375,469	55,000	55,467	15,722	31,205	99	115,582	38,036,953
2014Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	407,189	83,059	64,522	16,054	14,317	212	126,248	35,331,017
2015Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	392,669	87,130	56,683	15,383	19,819	314	115,453	30,404,900
2016Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	368,740	98,318	67,671	15,399	21,929	66	114,698	28,379,413
2017Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	360,396	140,880	67,239	15,024	25,384	211	107,631	29,819,953
2013Y	Kentucky Power Company	American Electric Power Company, Inc.	28,083	14,384	39,261	5,734	3,691	31	19,790	9,933,527
2014Y	Kentucky Power Company	American Electric Power Company, Inc.	64,696	22,065	45,049	6,201	4,938	54	21,802	11,993,933
2015Y	Kentucky Power Company	American Electric Power Company, Inc.	52,830	27,835	47,371	6,131	3,909	47	22,615	8,700,986
2016Y	Kentucky Power Company	American Electric Power Company, Inc.	45,534	34,927	49,489	5,707	6,544	94	21,711	7,276,047
2017Y	Kentucky Power Company	American Electric Power Company, Inc.	43,338	44,236	48,993	5,920	14,530	53	24,852	7,106,360
2013Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	75,169	76,921	73,808	18,603	21,640	115	51,846	19,239,394
2014Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	82,641	95,266	68,452	19,586	30,573	204	58,605	19,517,893
2015Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	79,419	100,058	71,355	19,118	30,579	159	56,457	18,916,965
2016Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	76,674	114,839	81,312	15,640	32,808	139	55,328	19,425,199
2017Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	73,654	137,834	97,537	14,920	35,115	171	55,904	19,052,676
2013Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	131,631	65,917	68,828	21,582	15,772	85	64,549	28,553,233
2014Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	142,741	80,473	73,292	22,604	15,240	163	72,366	28,644,882
2015Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	146,424	96,781	84,126	21,413	19,057	140	70,386	27,269,400
2016Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	155,056	120,301	77,198	20,475	17,268	118	75,617	26,169,526

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2017Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	139,452	119,772	85,913	19,948	15,362	153	68,484	26,257,034
2013Y	Alaska Electric Light and Power Company	Avista Corporation	2,409	524	2,848	1,160	5	0	4,316	377,005
2014Y	Alaska Electric Light and Power Company	Avista Corporation	2,643	556	2,772	1,168	2	0	4,191	422,784
2015Y	Alaska Electric Light and Power Company	Avista Corporation	2,508	470	2,755	1,114	4	0	4,429	398,066
2016Y	Alaska Electric Light and Power Company	Avista Corporation	2,331	623	2,877	1,109	4	0	4,330	395,154
2017Y	Alaska Electric Light and Power Company	Avista Corporation	3,056	718	3,148	1,182	19	0	4,576	414,210
2013Y	Avista Corporation	Avista Corporation	56,278	30,263	31,871	15,187	21,884	7	64,056	13,318,994
2014Y	Avista Corporation	Avista Corporation	56,655	31,164	32,653	14,540	26,943	0	67,943	12,839,533
2015Y	Avista Corporation	Avista Corporation	55,064	29,542	35,900	15,539	25,612	0	73,623	11,942,035
2016Y	Avista Corporation	Avista Corporation	62,028	31,090	32,193	16,702	24,905	0	73,986	11,733,626
2017Y	Avista Corporation	Avista Corporation	62,531	33,349	32,837	16,191	30,382	0	71,968	11,980,805
2013Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	242,128	48,509	92,116	26,766	56,919	4,769	77,455	32,680,735
2014Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	249,240	53,065	92,165	28,091	78,013	4,617	72,945	32,499,927
2015Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	252,203	57,875	82,796	27,460	80,221	3,602	68,170	31,832,657
2016Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	232,144	67,180	79,336	27,496	85,276	3,658	63,771	32,475,023
2017Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	275,887	77,396	88,643	27,940	107,483	3,769	59,530	33,727,302
2013Y	Nevada Power Company	Berkshire Hathaway Inc.	114,834	32,532	37,296	42,720	68,921	218	139,802	24,064,426
2014Y	Nevada Power Company	Berkshire Hathaway Inc.	85,771	76,754	38,593	40,032	53,978	135	115,901	22,745,488
2015Y	Nevada Power Company	Berkshire Hathaway Inc.	80,039	47,215	24,900	39,787	62,223	147	99,676	25,481,621
2016Y	Nevada Power Company	Berkshire Hathaway Inc.	82,773	59,480	25,690	40,887	62,873	193	99,466	25,062,084
2017Y	Nevada Power Company	Berkshire Hathaway Inc.	73,355	59,167	26,906	41,320	42,560	215	104,964	23,751,206
2013Y	PacifiCorp	Berkshire Hathaway Inc.	404,762	198,670	208,439	87,534	116,605	0	175,800	65,869,008
2014Y	PacifiCorp	Berkshire Hathaway Inc.	410,762	211,058	207,564	85,292	136,012	0	103,887	65,269,524
2015Y	PacifiCorp	Berkshire Hathaway Inc.	374,342	215,664	207,035	81,366	135,712	0	134,217	63,530,663
2016Y	PacifiCorp	Berkshire Hathaway Inc.	386,433	203,261	196,498	83,187	147,415	0	129,633	60,958,902
2017Y	PacifiCorp	Berkshire Hathaway Inc.	368,299	204,806	197,649	86,106	91,522	0	142,110	62,468,319
2013Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	36,047	14,419	22,969	13,429	18,622	562	59,898	9,185,572
2014Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	30,855	11,772	21,817	10,592	6,712	547	50,018	8,882,408
2015Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	38,561	14,795	23,601	9,477	11,264	466	46,684	8,911,051
2016Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	34,481	14,406	24,350	9,315	14,571	523	47,076	9,000,293
2017Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	33,482	12,820	26,965	9,047	13,243	483	45,622	9,198,853
2013Y	Black Hills Power, Inc.	Black Hills Corporation	19,144	22,962	8,902	2,850	1,338	39	30,256	3,084,298
2014Y	Black Hills Power, Inc.	Black Hills Corporation	17,967	24,294	9,814	3,251	1,536	25	29,891	2,905,098
2015Y	Black Hills Power, Inc.	Black Hills Corporation	17,920	23,464	9,615	3,239	1,717	4	26,141	2,873,371
2016Y	Black Hills Power, Inc.	Black Hills Corporation	18,233	25,302	10,470	3,037	1,498	2	23,125	2,611,946
2017Y	Black Hills Power, Inc.	Black Hills Corporation	21,366	27,381	12,668	3,005	1,010	3	25,139	2,992,386
2013Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	6,409	14,351	2,904	1,098	773	8	7,880	1,635,140
2014Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	7,053	15,848	3,433	1,082	812	6	9,082	1,639,680
2015Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	9,286	15,775	3,449	961	644	3	10,740	1,418,697
2016Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	8,334	17,817	3,634	885	457	5	9,537	1,559,870
2017Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	9,353	19,084	4,296	798	287	2	10,526	1,647,647
2013Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	16,049	87,363	33,895	8,549	3,771	3	51,916	4,853,495
2014Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	16,489	92,767	33,687	8,949	3,375	23	46,640	4,713,347
2015Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	15,524	98,295	32,541	9,145	2,572	28	43,845	4,751,076

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2016Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	15,537	95,650	35,159	7,523	2,452	122	39,113	4,688,744
2017Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	17,461	98,609	36,333	5,479	2,483	77	41,130	4,633,551
2013Y	Cleco Power LLC	Cleco Partners LP	75,683	18,949	28,603	11,227	5,919	4,529	54,127	11,115,732
2014Y	Cleco Power LLC	Cleco Partners LP	89,393	29,412	29,011	10,857	5,911	4,834	57,395	12,201,940
2015Y	Cleco Power LLC	Cleco Partners LP	82,444	30,764	30,537	12,231	9,111	5,911	60,469	12,105,640
2016Y	Cleco Power LLC	Cleco Partners LP	89,044	37,925	30,383	15,195	8,265	4,870	55,673	11,596,427
2017Y	Cleco Power LLC	Cleco Partners LP	84,807	35,421	30,776	13,176	8,402	4,153	54,702	11,279,584
2013Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	142,781	149,148	474,143	227,454	288,861	9,641	972,467	47,335,320
2014Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	146,111	134,741	512,137	235,949	341,180	0	973,181	46,406,542
2015Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	164,824	149,154	535,169	216,744	380,851	0	886,291	47,202,850
2016Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	157,574	161,227	512,680	200,873	387,254	0	866,797	47,450,242
2017Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	126,729	174,857	518,530	211,764	416,725	0	669,606	46,342,045
2013Y	Virginia Electric and Power Company	Dominion Energy, Inc.	666,709	40,470	185,193	84,749	24,653	0	388,641	82,852,117
2014Y	Virginia Electric and Power Company	Dominion Energy, Inc.	1,244,953	22,275	174,005	103,838	32,437	0	330,798	83,938,195
2015Y	Virginia Electric and Power Company	Dominion Energy, Inc.	835,540	100,092	178,553	89,770	37,651	0	354,234	85,178,907
2016Y	Virginia Electric and Power Company	Dominion Energy, Inc.	983,460	99,432	240,017	80,534	43,352	0	377,040	87,875,099
2017Y	Virginia Electric and Power Company	Dominion Energy, Inc.	718,254	-7,109	193,283	81,089	37,397	88	345,628	84,969,889
2013Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	814,070	55,116	191,804	79,219	28,943	1,427	575,778	85,789,697
2014Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	927,885	56,473	244,244	78,523	21,845	7,325	460,331	87,645,520
2015Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	967,351	57,407	244,757	81,499	19,266	9,243	532,642	87,375,571
2016Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	938,315	57,317	270,760	83,506	20,610	10,355	491,096	88,544,715
2017Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	862,540	53,374	276,189	84,236	20,720	11,583	414,143	87,306,564
2013Y	Duke Energy Florida, LLC	Duke Energy Corporation	198,702	41,237	135,030	46,992	94,825	1,937	279,602	38,164,155
2014Y	Duke Energy Florida, LLC	Duke Energy Corporation	224,282	35,842	146,828	57,525	115,469	2,331	237,312	38,728,049
2015Y	Duke Energy Florida, LLC	Duke Energy Corporation	227,289	36,495	150,197	57,771	83,883	3,657	242,876	39,989,379
2016Y	Duke Energy Florida, LLC	Duke Energy Corporation	215,910	35,381	148,788	59,606	101,995	4,499	257,542	40,660,935
2017Y	Duke Energy Florida, LLC	Duke Energy Corporation	203,837	46,549	149,549	57,717	97,908	7,284	217,891	40,290,293
2013Y	Duke Energy Indiana, LLC	Duke Energy Corporation	238,332	46,188	78,965	39,353	11,036	270	197,917	33,714,982
2014Y	Duke Energy Indiana, LLC	Duke Energy Corporation	296,486	49,651	82,121	40,233	6,905	2,209	155,383	33,433,620
2015Y	Duke Energy Indiana, LLC	Duke Energy Corporation	342,983	62,855	91,194	41,014	5,651	2,884	161,178	33,517,569
2016Y	Duke Energy Indiana, LLC	Duke Energy Corporation	334,891	76,550	99,680	27,491	5,087	3,560	152,284	34,368,826
2017Y	Duke Energy Indiana, LLC	Duke Energy Corporation	310,442	82,485	99,541	29,240	4,662	4,236	140,185	33,145,670
2013Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	38,223	10,230	10,273	6,495	1,506	51	23,632	4,546,692
2014Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	44,932	13,842	11,669	6,645	975	553	18,599	4,447,988
2015Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	41,299	16,184	12,448	6,599	563	909	20,732	5,277,786
2016Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	41,793	19,418	12,929	6,218	673	905	19,370	4,672,987
2017Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	38,495	17,246	18,190	5,442	593	889	19,497	4,908,072
2013Y	Duke Energy Progress, LLC	Duke Energy Corporation	714,642	61,419	130,114	44,157	51,420	1,800	349,517	60,204,063
2014Y	Duke Energy Progress, LLC	Duke Energy Corporation	778,772	54,336	178,322	49,288	4,646	4,171	296,661	62,871,047
2015Y	Duke Energy Progress, LLC	Duke Energy Corporation	838,358	38,719	138,636	52,930	3,708	5,624	299,516	64,880,560
2016Y	Duke Energy Progress, LLC	Duke Energy Corporation	769,221	46,483	165,907	47,900	4,480	6,307	340,666	69,052,154
2017Y	Duke Energy Progress, LLC	Duke Energy Corporation	700,775	38,809	153,498	46,977	4,083	6,208	314,453	66,822,736
2013Y	Southern California Edison Company	Edison International	575,021	316,012	461,916	191,060	598,329	14,170	1,190,561	90,552,978
2014Y	Southern California Edison Company	Edison International	292,094	243,690	494,881	177,028	629,097	11,300	1,164,602	116,437,195

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2015Y	Southern California Edison Company	Edison International	198,912	312,494	497,566	179,164	569,076	6,873	1,058,831	90,495,397
2016Y	Southern California Edison Company	Edison International	210,774	227,741	523,427	165,721	506,648	8,294	999,751	88,194,998
2017Y	Southern California Edison Company	Edison International	202,975	221,093	523,406	151,786	516,663	8,507	974,483	91,291,726
2013Y	El Paso Electric Company	El Paso Electric Company	108,855	16,765	21,740	17,602	200	0	125,348	10,884,241
2014Y	El Paso Electric Company	El Paso Electric Company	115,882	17,855	22,321	19,737	208	0	121,061	11,009,422
2015Y	El Paso Electric Company	El Paso Electric Company	121,637	19,120	22,881	19,148	222	0	116,878	10,915,601
2016Y	El Paso Electric Company	El Paso Electric Company	121,772	20,344	22,669	18,853	205	0	116,065	10,598,511
2017Y	El Paso Electric Company	El Paso Electric Company	123,198	21,078	22,224	19,432	205	0	117,862	10,904,754
2013Y	Tampa Electric Company	Emera Incorporated	127,725	12,705	48,426	23,344	47,774	1,431	145,127	18,639,927
2014Y	Tampa Electric Company	Emera Incorporated	139,500	13,840	49,304	29,204	46,848	560	132,051	18,784,911
2015Y	Tampa Electric Company	Emera Incorporated	148,732	14,223	52,920	26,215	46,989	803	123,601	19,121,762
2016Y	Tampa Electric Company	Emera Incorporated	153,589	16,125	52,325	34,013	37,694	689	123,403	19,440,142
2017Y	Tampa Electric Company	Emera Incorporated	135,729	14,411	48,089	39,070	38,208	551	119,348	19,425,418
2013Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA	NA	NA	NA	NA
2014Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA	NA	NA	NA	NA
2015Y	EL Investment Company, LLC	Entergy Corporation	182,161	37,473	41,061	24,090	6,034	1,295	119,789	31,482,380
2016Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA	NA	NA	NA	NA
2017Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA	NA	NA	NA	NA
2013Y	Entergy Arkansas, Inc.	Entergy Corporation	266,433	30,215	59,067	38,461	41,853	595	190,048	29,788,956
2014Y	Entergy Arkansas, Inc.	Entergy Corporation	281,655	43,309	68,806	36,880	68,221	774	181,182	31,350,781
2015Y	Entergy Arkansas, Inc.	Entergy Corporation	340,169	43,735	84,018	35,843	74,662	737	197,103	31,379,457
2016Y	Entergy Arkansas, Inc.	Entergy Corporation	346,461	40,348	77,522	34,220	66,675	611	185,467	29,363,790
2017Y	Entergy Arkansas, Inc.	Entergy Corporation	374,419	42,018	85,182	36,215	53,392	357	188,114	29,219,532
2013Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	182,715	28,052	26,253	17,739	2,468	2,409	137,996	27,130,595
2014Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	185,752	35,402	25,398	18,917	3,075	1,851	125,366	28,713,874
2015Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	139,861	28,828	21,667	12,662	3,683	1,218	94,552	21,426,698
2016Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA	NA	NA	NA	NA	NA
2017Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA	NA	NA	NA	NA	NA
2013Y	Entergy Louisiana, LLC	Entergy Corporation	217,860	36,229	49,808	31,816	3,353	2,147	169,784	34,156,904
2014Y	Entergy Louisiana, LLC	Entergy Corporation	227,387	50,685	51,360	34,157	4,986	2,047	158,484	37,479,888
2015Y	Entergy Louisiana, LLC	Entergy Corporation	106,279	23,696	21,714	11,956	2,770	1,302	86,301	14,743,976
2016Y	Entergy Louisiana, LLC	Entergy Corporation	440,050	83,851	80,745	46,151	12,876	3,396	284,408	63,634,403
2017Y	Entergy Louisiana, LLC	Entergy Corporation	459,538	93,619	87,570	51,910	14,704	3,406	285,412	61,747,129
2013Y	Entergy Mississippi, Inc.	Entergy Corporation	85,100	20,588	42,432	24,263	4,036	422	82,429	14,965,739
2014Y	Entergy Mississippi, Inc.	Entergy Corporation	72,995	21,980	33,675	24,275	4,873	1,339	93,348	16,054,977
2015Y	Entergy Mississippi, Inc.	Entergy Corporation	80,361	21,768	40,332	23,580	8,835	944	79,355	14,969,217
2016Y	Entergy Mississippi, Inc.	Entergy Corporation	70,690	21,512	44,578	21,021	6,801	587	80,510	14,462,253
2017Y	Entergy Mississippi, Inc.	Entergy Corporation	59,654	19,842	47,296	21,572	11,730	862	79,308	13,904,918
2013Y	Entergy New Orleans, LLC	Entergy Corporation	29,487	13,359	9,764	9,508	1,938	530	48,573	5,615,573
2014Y	Entergy New Orleans, LLC	Entergy Corporation	20,000	14,389	11,673	8,432	1,229	489	42,466	6,570,789
2015Y	Entergy New Orleans, LLC	Entergy Corporation	14,282	14,327	10,522	8,252	5,303	519	36,414	7,138,626
2016Y	Entergy New Orleans, LLC	Entergy Corporation	17,455	9,255	12,626	11,180	6,855	293	38,691	6,947,771
2017Y	Entergy New Orleans, LLC	Entergy Corporation	10,213	8,438	16,854	9,829	8,384	206	36,890	7,327,377
2013Y	Entergy Texas, Inc.	Entergy Corporation	56,402	27,746	34,215	17,710	12,601	337	102,265	23,811,698

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2014Y	Entergy Texas, Inc.	Entergy Corporation	56,065	30,688	33,681	18,046	8,046	418	80,724	22,661,605
2015Y	Entergy Texas, Inc.	Entergy Corporation	58,171	37,097	34,046	17,159	13,672	364	88,856	23,855,503
2016Y	Entergy Texas, Inc.	Entergy Corporation	47,088	28,775	32,599	16,632	9,509	227	80,734	23,892,632
2017Y	Entergy Texas, Inc.	Entergy Corporation	52,757	27,592	37,702	18,884	10,426	173	77,937	20,321,420
2013Y	Public Service Company of New Hampshire	Eversource Energy	45,816	36,701	60,787	29,001	18,751	42	108,755	9,118,546
2014Y	Public Service Company of New Hampshire	Eversource Energy	47,989	51,083	58,180	32,405	17,562	61	95,348	8,595,895
2015Y	Public Service Company of New Hampshire	Eversource Energy	53,638	33,959	64,753	34,226	16,026	24	95,309	8,441,532
2016Y	Public Service Company of New Hampshire	Eversource Energy	45,898	37,457	66,977	29,651	16,146	-10	89,542	8,388,691
2017Y	Public Service Company of New Hampshire	Eversource Energy	45,860	50,674	71,005	28,814	16,301	0	87,033	8,116,389
2013Y	Monongahela Power Company	FirstEnergy Corp.	69,442	104,745	34,233	15,100	3,520	0	3,568	10,816,852
2014Y	Monongahela Power Company	FirstEnergy Corp.	92,664	244,607	60,903	15,506	3,599	0	103,251	17,361,198
2015Y	Monongahela Power Company	FirstEnergy Corp.	93,540	140,798	67,261	21,219	3,889	13	49,864	16,163,874
2016Y	Monongahela Power Company	FirstEnergy Corp.	105,784	107,056	65,326	16,539	3,689	47	45,148	17,434,322
2017Y	Monongahela Power Company	FirstEnergy Corp.	104,487	87,565	65,980	18,017	5,040	97	88,527	17,497,075
2013Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	916	10,006	44,377	16,190	38,802	336	86,177	2,761,676
2014Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,007	11,048	44,142	19,691	43,955	270	82,731	2,623,309
2015Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,015	11,512	44,594	20,136	48,387	54	68,770	2,608,207
2016Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,040	11,238	44,997	17,538	42,612	11	68,939	2,684,357
2017Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,125	10,636	50,433	18,023	45,718	14	70,713	2,602,989
2013Y	Tucson Electric Power Company	Fortis Inc.	209,776	15,350	21,731	18,213	15,663	0	93,257	13,025,375
2014Y	Tucson Electric Power Company	Fortis Inc.	217,090	16,560	24,117	17,568	13,048	0	102,590	13,311,011
2015Y	Tucson Electric Power Company	Fortis Inc.	179,879	24,317	22,407	17,871	15,282	0	106,428	14,279,396
2016Y	Tucson Electric Power Company	Fortis Inc.	173,377	24,381	23,432	19,668	20,645	0	111,249	13,718,397
2017Y	Tucson Electric Power Company	Fortis Inc.	178,733	30,952	23,490	20,583	16,212	0	115,191	13,442,595
2013Y	UNS Electric, Inc.	Fortis Inc.	1,643	13,494	6,076	4,338	4,222	0	11,529	2,230,041
2014Y	UNS Electric, Inc.	Fortis Inc.	2,129	12,453	5,497	4,717	3,734	0	9,469	1,982,714
2015Y	UNS Electric, Inc.	Fortis Inc.	2,514	20,886	5,245	3,978	3,990	0	9,472	1,746,289
2016Y	UNS Electric, Inc.	Fortis Inc.	1,903	21,802	5,760	4,069	4,625	0	11,116	1,762,853
2017Y	UNS Electric, Inc.	Fortis Inc.	3,436	17,425	6,926	4,103	4,007	0	10,205	1,916,799
2013Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	189,884	53,986	53,615	19,211	13,659	423	155,758	21,683,329
2014Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	193,296	64,368	51,169	19,055	17,553	403	161,898	22,472,307
2015Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	182,519	75,630	53,422	20,274	32,898	470	160,805	20,796,733
2016Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	187,109	72,526	55,971	19,997	49,104	487	168,097	21,433,876
2017Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	179,727	85,899	56,071	20,531	43,008	574	156,680	21,322,723
2013Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	42,115	21,259	29,003	12,307	14,906	224	74,537	8,413,828
2014Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	41,437	37,937	32,301	12,119	21,176	219	74,615	8,511,766
2015Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	45,251	39,570	31,845	12,314	36,440	263	79,679	8,385,574
2016Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	48,570	37,371	34,872	12,344	31,427	274	81,446	8,465,650
2017Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	46,413	47,345	35,072	12,350	41,835	309	85,028	8,386,821
2013Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	3,005	43,677	128,820	60,942	76,423	5,734	118,188	19,115,201
2014Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,454	44,347	140,939	61,737	86,451	7,143	115,355	18,690,994
2015Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,500	46,526	126,688	71,348	95,109	7,165	111,757	17,887,199
2016Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,482	47,010	184,037	57,894	76,755	5,892	96,599	17,455,920
2017Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,402	42,068	230,586	61,159	86,040	7,986	88,542	16,633,428

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2013Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	4,381	11,098	45,602	26,811	43,239	2,862	72,913	9,024,632
2014Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,483	11,112	46,080	27,917	46,387	2,760	55,068	7,970,527
2015Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,673	16,811	52,426	35,119	51,733	5,876	54,907	7,319,681
2016Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,641	12,512	54,581	26,317	41,765	4,262	40,803	7,365,999
2017Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,384	10,116	65,432	29,911	46,488	5,033	39,870	7,216,272
2013Y	Idaho Power Co.	IDACORP, Inc.	86,431	26,450	46,979	21,841	44,062	0	151,020	16,302,681
2014Y	Idaho Power Co.	IDACORP, Inc.	86,811	27,336	46,305	25,549	35,814	0	155,933	16,312,786
2015Y	Idaho Power Co.	IDACORP, Inc.	90,116	27,353	48,358	21,157	39,575	80	140,370	15,518,629
2016Y	Idaho Power Co.	IDACORP, Inc.	90,883	25,408	50,033	20,845	42,924	0	146,887	15,381,629
2017Y	Idaho Power Co.	IDACORP, Inc.	91,581	25,279	50,643	22,428	46,084	0	142,691	16,706,603
2013Y	Kentucky Utilities Company	LKE	126,521	27,779	56,507	28,190	19,563	42	111,709	21,629,993
2014Y	Kentucky Utilities Company	LKE	151,052	30,428	60,874	34,679	18,365	94	99,819	21,986,858
2015Y	Kentucky Utilities Company	LKE	164,471	31,973	56,957	32,619	18,532	307	117,399	21,810,131
2016Y	Kentucky Utilities Company	LKE	158,852	31,677	57,318	32,262	22,509	817	108,557	21,437,963
2017Y	Kentucky Utilities Company	LKE	157,247	34,598	56,162	32,654	22,093	792	109,507	20,497,797
2013Y	Louisville Gas and Electric Company	LKE	121,061	14,397	46,074	11,099	15,059	42	84,240	14,478,316
2014Y	Louisville Gas and Electric Company	LKE	121,235	14,746	51,335	13,768	15,142	47	79,526	15,373,731
2015Y	Louisville Gas and Electric Company	LKE	115,873	14,636	49,032	12,601	14,306	610	81,077	13,502,213
2016Y	Louisville Gas and Electric Company	LKE	99,121	15,057	46,816	12,343	16,461	920	79,109	13,156,493
2017Y	Louisville Gas and Electric Company	LKE	97,987	15,343	45,209	12,706	16,456	1,032	76,486	13,133,134
2013Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	24,544	10,729	15,581	3,900	255	139	20,293	3,195,882
2014Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	25,377	13,968	15,440	4,111	261	166	20,256	3,331,202
2015Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	28,437	13,469	15,747	4,147	253	154	21,966	3,316,058
2016Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	33,014	34,017	15,619	4,897	256	107	24,873	3,303,555
2017Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	34,605	36,860	15,355	4,558	245	111	26,686	3,346,441
2013Y	Florida Power & Light Company	NextEra Energy, Inc.	651,527	90,853	265,813	134,779	137,369	4,799	407,062	107,373,794
2014Y	Florida Power & Light Company	NextEra Energy, Inc.	632,335	98,718	268,585	118,415	149,974	3,287	354,091	112,929,729
2015Y	Florida Power & Light Company	NextEra Energy, Inc.	655,886	103,510	274,770	110,574	102,185	4,597	347,310	119,405,262
2016Y	Florida Power & Light Company	NextEra Energy, Inc.	643,878	78,459	271,303	103,438	53,636	3,730	335,632	119,279,691
2017Y	Florida Power & Light Company	NextEra Energy, Inc.	628,288	98,668	1,446,795	97,736	57,440	8,069	443,699	117,873,183
2013Y	Northern Indiana Public Service Company	NiSource Inc.	164,651	29,449	48,247	21,117	576	923	183,441	17,468,011
2014Y	Northern Indiana Public Service Company	NiSource Inc.	175,209	31,374	43,588	20,345	505	967	202,804	18,186,288
2015Y	Northern Indiana Public Service Company	NiSource Inc.	182,919	35,857	41,331	19,140	371	928	211,596	16,758,427
2016Y	Northern Indiana Public Service Company	NiSource Inc.	211,800	44,263	43,824	17,248	543	1,222	220,923	16,831,194
2017Y	Northern Indiana Public Service Company	NiSource Inc.	233,456	46,177	49,602	15,422	739	1,484	221,425	16,725,564
2013Y	NorthWestern Corporation	NorthWestern Corporation	25,594	29,595	53,600	11,867	6,416	573	64,655	9,519,519
2014Y	NorthWestern Corporation	NorthWestern Corporation	34,844	28,579	50,360	12,706	6,400	615	64,785	10,006,908
2015Y	NorthWestern Corporation	NorthWestern Corporation	57,721	27,739	49,950	11,615	6,693	554	76,796	11,027,880
2016Y	NorthWestern Corporation	NorthWestern Corporation	47,994	30,330	43,025	10,627	6,601	503	78,502	9,037,846
2017Y	NorthWestern Corporation	NorthWestern Corporation	50,120	43,449	44,613	13,096	6,031	522	82,653	8,924,244
2013Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	122,705	109,160	80,209	22,210	31,269	6,107	111,759	28,578,159
2014Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	125,035	122,725	80,858	21,054	35,892	8,242	118,327	30,234,927
2015Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	119,512	133,786	74,150	20,171	39,927	4,682	133,349	28,867,056
2016Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	122,547	168,202	80,041	21,973	50,081	4,713	141,320	29,762,475

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2017Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	121,907	168,890	96,565	23,292	50,967	4,749	137,559	28,111,471
2013Y	Otter Tail Power Company	Otter Tail Corporation	27,024	19,286	16,699	13,422	8,132	623	39,523	6,219,751
2014Y	Otter Tail Power Company	Otter Tail Corporation	32,535	23,817	16,511	13,358	8,029	493	41,787	5,470,896
2015Y	Otter Tail Power Company	Otter Tail Corporation	30,547	27,080	15,514	12,791	8,864	313	42,025	4,709,464
2016Y	Otter Tail Power Company	Otter Tail Corporation	31,649	32,582	16,791	12,476	10,781	345	44,695	4,955,630
2017Y	Otter Tail Power Company	Otter Tail Corporation	31,100	31,130	17,762	12,912	9,358	339	45,577	5,040,591
2013Y	Pacific Gas and Electric Company	PG&E Corporation	622,080	227,245	629,019	248,874	616,738	13,922	978,665	88,322,913
2014Y	Pacific Gas and Electric Company	PG&E Corporation	591,994	243,048	675,094	216,187	614,606	10,382	1,018,104	88,189,685
2015Y	Pacific Gas and Electric Company	PG&E Corporation	675,716	286,712	829,694	222,794	631,523	2,979	1,052,736	87,981,023
2016Y	Pacific Gas and Electric Company	PG&E Corporation	693,646	296,115	933,331	212,307	611,149	2,273	1,329,265	85,067,412
2017Y	Pacific Gas and Electric Company	PG&E Corporation	589,784	300,976	726,324	215,958	512,904	1,195	1,178,530	88,175,650
2013Y	Arizona Public Service Company	Pinnacle West Capital Corporation	416,257	72,068	96,398	52,597	77,723	9,332	213,793	32,087,545
2014Y	Arizona Public Service Company	Pinnacle West Capital Corporation	438,186	79,638	92,229	52,544	60,160	9,974	192,118	32,951,388
2015Y	Arizona Public Service Company	Pinnacle West Capital Corporation	438,805	83,335	95,469	52,455	55,010	11,296	167,749	33,628,854
2016Y	Arizona Public Service Company	Pinnacle West Capital Corporation	406,108	81,642	104,812	54,257	59,023	12,389	186,773	31,928,046
2017Y	Arizona Public Service Company	Pinnacle West Capital Corporation	414,065	82,704	109,284	59,041	54,410	13,872	183,317	30,910,170
2013Y	Public Service Company of New Mexico	PNM Resources, Inc.	181,117	38,078	24,289	15,288	961	5,299	135,149	12,001,980
2014Y	Public Service Company of New Mexico	PNM Resources, Inc.	190,525	38,628	21,773	15,368	748	4,814	131,296	11,836,387
2015Y	Public Service Company of New Mexico	PNM Resources, Inc.	180,839	37,692	22,882	14,956	1,283	4,792	140,392	11,541,512
2016Y	Public Service Company of New Mexico	PNM Resources, Inc.	141,433	34,985	19,744	14,810	644	4,099	149,173	12,280,191
2017Y	Public Service Company of New Mexico	PNM Resources, Inc.	132,281	36,621	20,667	15,166	457	4,385	151,950	12,454,143
2013Y	Portland General Electric Company	Portland General Electric Company	98,303	88,564	86,417	48,824	13,288	0	157,719	21,226,863
2014Y	Portland General Electric Company	Portland General Electric Company	115,252	96,567	99,839	51,831	14,179	0	161,772	21,080,082
2015Y	Portland General Electric Company	Portland General Electric Company	122,543	98,092	101,417	54,700	15,058	0	171,798	20,859,230
2016Y	Portland General Electric Company	Portland General Electric Company	126,752	95,365	116,611	56,434	14,192	0	176,471	21,247,271
2017Y	Portland General Electric Company	Portland General Electric Company	135,641	104,282	127,637	58,493	15,696	0	190,763	21,328,945
2013Y	Puget Sound Energy, Inc.	Puget Holdings LLC	116,054	114,098	77,322	51,298	105,724	288	109,153	26,265,216
2014Y	Puget Sound Energy, Inc.	Puget Holdings LLC	112,835	130,002	84,585	59,106	113,232	526	108,863	21,968,767
2015Y	Puget Sound Energy, Inc.	Puget Holdings LLC	117,453	130,460	82,427	49,097	118,438	389	110,378	28,183,148
2016Y	Puget Sound Energy, Inc.	Puget Holdings LLC	126,238	134,458	86,298	48,803	114,318	384	120,326	29,143,765
2017Y	Puget Sound Energy, Inc.	Puget Holdings LLC	125,003	138,493	76,282	49,274	126,051	769	128,643	27,227,367
2013Y	South Carolina Electric & Gas Co.	SCANA Corporation	187,531	18,376	46,623	46,737	7,698	1,625	163,369	22,326,578
2014Y	South Carolina Electric & Gas Co.	SCANA Corporation	184,994	21,707	51,470	48,801	9,578	1,636	169,415	23,332,942
2015Y	South Carolina Electric & Gas Co.	SCANA Corporation	184,858	17,983	56,138	47,994	13,430	1,755	166,943	23,114,845
2016Y	South Carolina Electric & Gas Co.	SCANA Corporation	189,161	17,972	55,248	47,831	14,770	1,425	191,727	23,471,194
2017Y	South Carolina Electric & Gas Co.	SCANA Corporation	193,840	23,053	55,485	46,520	14,367	1,469	166,141	22,879,069
2013Y	San Diego Gas & Electric Co.	Sempra Energy	351,746	95,859	128,782	53,797	148,373	0	628,738	32,916,382
2014Y	San Diego Gas & Electric Co.	Sempra Energy	98,921	81,094	112,219	43,897	157,667	0	590,458	30,952,957
2015Y	San Diego Gas & Electric Co.	Sempra Energy	46,228	85,341	141,442	45,453	173,383	0	455,443	33,132,033
2016Y	San Diego Gas & Electric Co.	Sempra Energy	44,657	87,877	141,031	44,111	208,005	0	400,172	29,443,890
2017Y	San Diego Gas & Electric Co.	Sempra Energy	40,121	87,096	144,376	46,369	174,580	0	425,629	29,300,970
2013Y	Alabama Power Company	Southern Company	553,407	60,633	170,411	90,103	34,907	9,154	351,531	66,309,626
2014Y	Alabama Power Company	Southern Company	676,877	73,289	188,700	100,081	38,459	8,779	360,311	67,155,314
2015Y	Alabama Power Company	Southern Company	671,108	71,603	177,116	97,311	40,201	9,180	413,430	63,847,336

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2016Y	Alabama Power Company	Southern Company	693,994	81,966	184,276	94,943	42,361	6,972	387,122	63,873,423
2017Y	Alabama Power Company	Southern Company	737,698	88,563	239,283	89,807	48,938	6,618	426,571	63,290,561
2013Y	Georgia Power Company	Southern Company	590,054	107,047	237,660	135,041	72,749	43,330	445,491	84,726,779
2014Y	Georgia Power Company	Southern Company	706,854	132,535	302,102	154,531	88,588	55,105	448,174	89,190,865
2015Y	Georgia Power Company	Southern Company	850,183	108,279	276,806	154,823	94,667	56,593	463,892	87,859,128
2016Y	Georgia Power Company	Southern Company	692,145	139,315	302,244	154,466	98,184	63,588	472,842	89,686,468
2017Y	Georgia Power Company	Southern Company	598,495	105,047	268,673	137,123	83,472	58,694	410,706	86,478,222
2013Y	Gulf Power Company	Southern Company	105,051	20,792	42,915	21,295	35,993	1,186	80,099	14,909,545
2014Y	Gulf Power Company	Southern Company	132,376	25,233	46,843	25,421	25,819	1,460	81,740	16,028,868
2015Y	Gulf Power Company	Southern Company	130,188	25,807	45,678	24,629	30,098	1,391	91,589	14,031,937
2016Y	Gulf Power Company	Southern Company	124,416	26,960	45,456	25,341	23,677	1,132	85,198	14,616,769
2017Y	Gulf Power Company	Southern Company	132,590	26,683	48,030	26,321	27,078	1,391	92,689	15,445,454
2013Y	Mississippi Power Company	Southern Company	121,325	14,835	34,358	17,838	5,798	4,175	83,327	14,591,834
2014Y	Mississippi Power Company	Southern Company	123,594	13,197	36,912	16,158	7,922	4,941	88,045	17,059,643
2015Y	Mississippi Power Company	Southern Company	103,186	11,705	32,805	13,746	10,273	4,742	95,356	16,487,788
2016Y	Mississippi Power Company	Southern Company	113,417	15,573	36,118	16,769	10,008	4,293	100,982	14,866,485
2017Y	Mississippi Power Company	Southern Company	107,505	11,013	31,566	15,719	9,078	2,884	87,559	15,283,882
2013Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	73,907	13,676	15,196	6,427	619	13,259	39,735	5,993,477
2014Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	77,206	15,566	15,881	5,880	592	12,227	39,876	6,240,584
2015Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	69,734	17,885	15,461	6,189	323	8,294	36,736	5,795,918
2016Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	68,618	21,206	15,350	5,908	617	10,444	38,839	5,610,259
2017Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	64,362	17,802	16,055	6,402	552	9,117	42,948	5,220,819
2013Y	Kansas Gas and Electric Company	Westar Energy, Inc.	155,715	100,515	41,913	12,619	1,827	0	103,866	10,605,055
2014Y	Kansas Gas and Electric Company	Westar Energy, Inc.	158,083	124,606	45,361	15,741	1,765	0	99,352	10,800,465
2015Y	Kansas Gas and Electric Company	Westar Energy, Inc.	144,822	125,341	36,881	13,961	1,713	1	106,387	10,761,626
2016Y	Kansas Gas and Electric Company	Westar Energy, Inc.	148,087	127,328	42,611	15,625	1,621	0	102,900	11,297,034
2017Y	Kansas Gas and Electric Company	Westar Energy, Inc.	140,840	132,014	40,354	14,004	1,559	0	99,142	10,847,878
2013Y	Westar Energy (KPL)	Westar Energy, Inc.	86,267	102,195	59,147	14,214	1,851	0	97,746	17,484,374
2014Y	Westar Energy (KPL)	Westar Energy, Inc.	94,279	126,821	49,269	13,976	1,868	0	107,569	18,531,716
2015Y	Westar Energy (KPL)	Westar Energy, Inc.	86,642	129,031	49,632	15,837	1,933	1	114,098	17,180,535
2016Y	Westar Energy (KPL)	Westar Energy, Inc.	89,882	130,856	45,165	17,854	1,935	0	107,220	16,555,817
2017Y	Westar Energy (KPL)	Westar Energy, Inc.	91,347	133,385	42,538	17,040	1,942	0	100,252	18,790,662
2013Y	Northern States Power Company - MN	Xcel Energy Inc.	539,629	244,340	121,107	55,250	84,666	18	254,713	37,474,524
2014Y	Northern States Power Company - MN	Xcel Energy Inc.	575,094	272,848	117,778	58,047	124,080	9	257,214	39,129,144
2015Y	Northern States Power Company - MN	Xcel Energy Inc.	546,532	309,442	106,452	55,350	69,454	2	263,079	39,484,126
2016Y	Northern States Power Company - MN	Xcel Energy Inc.	541,210	355,752	110,969	55,996	89,936	1	265,532	41,519,021
2017Y	Northern States Power Company - MN	Xcel Energy Inc.	509,376	369,339	111,166	55,401	106,677	5	269,990	40,720,489
2013Y	Northern States Power Company - WI	Xcel Energy Inc.	21,350	47,064	25,725	10,015	10,571	82	41,603	6,562,368
2014Y	Northern States Power Company - WI	Xcel Energy Inc.	21,835	58,765	24,836	10,384	11,134	80	41,794	6,750,889
2015Y	Northern States Power Company - WI	Xcel Energy Inc.	20,208	46,131	24,951	9,835	11,158	72	44,911	6,647,300
2016Y	Northern States Power Company - WI	Xcel Energy Inc.	19,519	66,586	25,096	9,336	12,318	55	41,367	6,641,542
2017Y	Northern States Power Company - WI	Xcel Energy Inc.	20,257	80,072	26,246	9,663	12,252	53	44,065	6,727,740
2013Y	Public Service Company of Colorado	Xcel Energy Inc.	185,844	61,572	103,101	38,200	125,572	641	167,001	33,450,187
2014Y	Public Service Company of Colorado	Xcel Energy Inc.	182,309	58,061	94,666	37,413	130,409	528	163,014	32,498,488

Notes: Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.
Represents only Vertically-Integrated Utilities

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Total Trans. O&M Expense ($000)	Total Distrib. O&M Expense ($000)	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Public Service Company of Colorado	Xcel Energy Inc.	181,422	52,952	92,990	33,293	121,395	589	166,379	32,396,474
2016Y	Public Service Company of Colorado	Xcel Energy Inc.	169,248	53,338	96,620	34,860	107,952	651	165,928	34,472,722
2017Y	Public Service Company of Colorado	Xcel Energy Inc.	157,317	54,763	97,636	34,160	113,706	627	177,229	36,486,396
2013Y	Southwestern Public Service Company	Xcel Energy Inc.	94,795	115,728	35,179	15,423	15,588	189	96,828	28,292,788
2014Y	Southwestern Public Service Company	Xcel Energy Inc.	97,876	126,490	36,160	15,673	15,174	188	100,214	28,265,391
2015Y	Southwestern Public Service Company	Xcel Energy Inc.	105,699	145,594	38,256	15,664	16,439	149	107,892	28,414,831
2016Y	Southwestern Public Service Company	Xcel Energy Inc.	95,099	173,307	30,994	20,045	19,019	136	101,761	28,383,129
2017Y	Southwestern Public Service Company	Xcel Energy Inc.	90,072	191,522	36,120	18,382	18,484	128	105,746	27,124,064
		Total	67,941,511	23,661,254	34,166,002	13,346,944	18,182,117	901,974	60,604,922	9,401,252,322

Generation Rankings [2013-2017]   Source: SNL

Holding Company	Non Fuel O&M	Net Generation (MWh)	Non-fuel O&M/Net Gen	Ranking
Iberdrola, S.A.	31,405,000	70,139,534	0.45	1
NextEra Energy, Inc.	3,211,914,000	575,259,683	5.58	2
OGE Energy Corp.	611,706,000	107,763,653	5.68	3
IDACORP, Inc.	445,822,000	65,279,206	6.83	4
Berkshire Hathaway Inc.	3,806,398,000	545,388,710	6.98	5
Cleco Partners LP	421,371,000	56,962,384	7.40	6
Alliant Energy Corporation	692,492,000	93,129,152	7.44	7
Ameren Corporation	1,563,045,000	208,840,970	7.48	8
Emera Incorporated	705,275,000	93,498,595	7.54	9
LKE	1,313,419,953	169,651,107	7.74	10
ALLETE, Inc.	379,907,000	47,128,681	8.06	11
Algonquin Power & Utilities Corp.	177,653,000	21,964,593	8.09	12
Avista Corporation	305,503,000	37,483,055	8.15	13
CMS Energy Corporation	732,466,000	87,832,810	8.34	14
NorthWestern Corporation	216,273,000	24,427,979	8.85	15
SCANA Corporation	1,008,594,000	113,329,114	8.90	16
Great Plains Energy Incorporated	1,156,321,000	119,899,377	9.64	17
Otter Tail Corporation	152,855,000	15,289,737	10.00	18
Puget Holdings LLC	597,583,000	59,212,529	10.09	19
Portland General Electric Co	598,491,000	59,091,390	10.13	20
Westar Energy, Inc.	1,219,893,000	119,625,576	10.20	21
Southern Company	8,231,012,000	799,420,182	10.30	22
AES Corporation	1,283,281,000	122,636,056	10.46	23
AEP	5,747,192,000	543,870,739	10.57	24
Duke Energy Corporation	11,109,825,000	1,042,824,027	10.65	25
MGE Energy, Inc.	123,231,000	10,962,864	11.24	26
Xcel Energy Inc.	4,174,691,000	362,060,608	11.53	27
Entergy Corporation	5,233,741,000	453,433,196	11.54	28

Generation Rankings [2013-2017]   Source: SNL

Holding Company	Non Fuel O&M	Net Generation (MWh)	Non-fuel O&M/Net Gen	Ranking
Black Hills Corporation	157,654,000	13,221,742	11.92	29
MDU Resources Group, Inc.	145,977,000	12,105,501	12.06	30
DTE Energy Company	2,458,520,000	199,945,050	12.30	31
Dominion Energy, Inc.	4,448,916,000	360,334,594	12.35	32
El Paso Electric Company	591,344,000	46,121,872	12.82	33
Wisconsin River Power Company	9,897,000	719,940	13.75	34
Vectren Corporation	353,827,000	24,423,636	14.49	35
NiSource Inc.	968,035,000	65,302,800	14.82	36
PNM Resources, Inc.	826,195,000	51,248,675	16.12	37
Pinnacle West Capital Corporation	2,113,421,000	130,365,234	16.21	38
Fortis Inc.	975,583,000	57,979,323	16.83	39
PG&E Corporation	3,173,220,000	158,099,798	20.07	40
Caisse de dépôt	81,060,000	3,939,143	20.58	41
Edison International	1,479,776,000	71,524,523	20.69	42
WEC Energy Group, Inc.	3,652,165,000	173,560,614	21.04	43
National Grid plc	467,410,000	22,207,874	21.05	44
FirstEnergy Corp.	2,305,128,000	106,354,119	21.67	45
Balfour Beatty Infrastructure	13,363,000	591,939	22.57	46
Sempra Energy	581,673,000	23,532,613	24.72	47
Eversource Energy	240,195,000	8,132,393	29.54	48
Consolidated Edison, Inc.	738,019,000	15,047,088	49.05	49
Grand Total	81,032,737,953	7,571,163,978		

Q1	8.15
Q2	10.65
Q3	16.12
Industry Avg.	10.70

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Dayton Power and Light Company	AES Corporation	118,804	14,813,091
2014Y	Dayton Power and Light Company	AES Corporation	123,183	12,822,963
2015Y	Dayton Power and Light Company	AES Corporation	126,765	10,618,730
2016Y	Dayton Power and Light Company	AES Corporation	116,260	11,096,105
2017Y	Dayton Power and Light Company	AES Corporation	82,181	7,610,986
2013Y	Indianapolis Power & Light Company	AES Corporation	135,886	15,219,200
2014Y	Indianapolis Power & Light Company	AES Corporation	132,103	15,873,565
2015Y	Indianapolis Power & Light Company	AES Corporation	154,809	12,526,781
2016Y	Indianapolis Power & Light Company	AES Corporation	149,247	11,437,551
2017Y	Indianapolis Power & Light Company	AES Corporation	144,043	10,617,084
2013Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	29,656	4,323,826
2014Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	32,415	3,807,870
2015Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	37,811	3,835,300
2016Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	37,151	4,727,423
2017Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	40,620	5,270,174
2013Y	ALLETE (Minnesota Power)	ALLETE, Inc.	81,069	9,555,798
2014Y	ALLETE (Minnesota Power)	ALLETE, Inc.	80,954	9,386,748
2015Y	ALLETE (Minnesota Power)	ALLETE, Inc.	78,932	9,555,128
2016Y	ALLETE (Minnesota Power)	ALLETE, Inc.	72,982	9,711,128
2017Y	ALLETE (Minnesota Power)	ALLETE, Inc.	65,970	8,919,879
2013Y	Interstate Power and Light Company	Alliant Energy Corporation	60,571	8,285,902
2014Y	Interstate Power and Light Company	Alliant Energy Corporation	67,416	8,794,580
2015Y	Interstate Power and Light Company	Alliant Energy Corporation	67,248	8,793,970
2016Y	Interstate Power and Light Company	Alliant Energy Corporation	60,987	8,072,355
2017Y	Interstate Power and Light Company	Alliant Energy Corporation	62,785	9,980,512

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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Wisconsin Power and Light Company	Alliant Energy Corporation	80,423	10,386,877
2014Y	Wisconsin Power and Light Company	Alliant Energy Corporation	84,087	9,596,204
2015Y	Wisconsin Power and Light Company	Alliant Energy Corporation	73,059	10,612,929
2016Y	Wisconsin Power and Light Company	Alliant Energy Corporation	69,547	9,061,588
2017Y	Wisconsin Power and Light Company	Alliant Energy Corporation	66,369	9,544,235
2013Y	Union Electric Company	Ameren Corporation	309,718	43,212,928
2014Y	Union Electric Company	Ameren Corporation	315,539	43,473,514
2015Y	Union Electric Company	Ameren Corporation	347,345	42,423,476
2016Y	Union Electric Company	Ameren Corporation	296,877	38,576,901
2017Y	Union Electric Company	Ameren Corporation	293,566	41,154,151
2013Y	AEP Generating Company	American Electric Power Company, Inc.	123,953	10,546,276
2014Y	AEP Generating Company	American Electric Power Company, Inc.	129,075	11,675,906
2015Y	AEP Generating Company	American Electric Power Company, Inc.	134,770	12,994,269
2016Y	AEP Generating Company	American Electric Power Company, Inc.	128,438	13,491,086
2017Y	AEP Generating Company	American Electric Power Company, Inc.	112,270	6,069,003
2013Y	AEP Texas North Company	American Electric Power Company, Inc.	15,551	2,435,181
2014Y	AEP Texas North Company	American Electric Power Company, Inc.	19,983	1,897,864
2015Y	AEP Texas North Company	American Electric Power Company, Inc.	17,338	1,212,431
2016Y	AEP Texas North Company	American Electric Power Company, Inc.	13,325	1,381,335
2017Y	AEP Texas, Inc.	American Electric Power Company, Inc.	12,384	923,586
2013Y	Appalachian Power Company	American Electric Power Company, Inc.	194,328	21,383,209
2014Y	Appalachian Power Company	American Electric Power Company, Inc.	252,109	29,428,638
2015Y	Appalachian Power Company	American Electric Power Company, Inc.	226,788	27,839,387
2016Y	Appalachian Power Company	American Electric Power Company, Inc.	219,726	27,096,755
2017Y	Appalachian Power Company	American Electric Power Company, Inc.	211,709	25,686,531

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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	375,469	26,425,406
2014Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	407,189	28,700,648
2015Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	392,669	24,137,360
2016Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	368,740	21,255,381
2017Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	360,396	23,185,309
2013Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	67,279	5,511,874
2014Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	67,921	5,968,451
2015Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	67,014	5,214,734
2016Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	63,925	5,012,711
2017Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	65,209	6,064,762
2013Y	Kentucky Power Company	American Electric Power Company, Inc.	28,083	2,764,447
2014Y	Kentucky Power Company	American Electric Power Company, Inc.	64,696	8,944,397
2015Y	Kentucky Power Company	American Electric Power Company, Inc.	52,830	5,821,424
2016Y	Kentucky Power Company	American Electric Power Company, Inc.	45,534	4,372,069
2017Y	Kentucky Power Company	American Electric Power Company, Inc.	43,338	4,407,133
2013Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	75,192	4,966,617
2014Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	76,444	5,441,556
2015Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	75,437	3,680,528
2016Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	68,000	4,934,165
2017Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	67,219	5,899,936
2013Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	75,169	12,498,357
2014Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	82,641	10,389,861
2015Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	79,419	9,452,305
2016Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	76,674	6,357,040
2017Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	73,654	5,214,296

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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	131,631	23,126,139
2014Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	142,741	22,949,594
2015Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	146,424	20,266,536
2016Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	155,056	18,582,835
2017Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	139,452	18,263,411
2013Y	Alaska Electric Light and Power Company	Avista Corporation	2,409	148,485
2014Y	Alaska Electric Light and Power Company	Avista Corporation	2,643	143,844
2015Y	Alaska Electric Light and Power Company	Avista Corporation	2,508	152,097
2016Y	Alaska Electric Light and Power Company	Avista Corporation	2,331	149,485
2017Y	Alaska Electric Light and Power Company	Avista Corporation	3,056	130,872
2013Y	Avista Corporation	Avista Corporation	56,278	7,029,105
2014Y	Avista Corporation	Avista Corporation	56,655	7,395,385
2015Y	Avista Corporation	Avista Corporation	55,064	7,417,221
2016Y	Avista Corporation	Avista Corporation	62,028	7,462,256
2017Y	Avista Corporation	Avista Corporation	62,531	7,454,305
2013Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	2,813	76,295
2014Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	2,734	125,755
2015Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	2,295	113,142
2016Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	2,765	127,487
2017Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	2,756	149,260
2013Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	242,128	29,836,430
2014Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	249,240	30,155,456
2015Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	252,203	29,215,286
2016Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	232,144	29,331,423
2017Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	275,887	30,740,402

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Nevada Power Company	Berkshire Hathaway Inc.	114,834	17,294,612
2014Y	Nevada Power Company	Berkshire Hathaway Inc.	85,771	17,026,153
2015Y	Nevada Power Company	Berkshire Hathaway Inc.	80,039	18,743,765
2016Y	Nevada Power Company	Berkshire Hathaway Inc.	82,773	18,527,929
2017Y	Nevada Power Company	Berkshire Hathaway Inc.	73,355	17,363,637
2013Y	PacifiCorp	Berkshire Hathaway Inc.	404,762	58,376,572
2014Y	PacifiCorp	Berkshire Hathaway Inc.	410,762	60,205,324
2015Y	PacifiCorp	Berkshire Hathaway Inc.	374,342	56,331,039
2016Y	PacifiCorp	Berkshire Hathaway Inc.	386,433	53,570,341
2017Y	PacifiCorp	Berkshire Hathaway Inc.	368,299	52,431,037
2013Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	36,047	5,142,897
2014Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	30,855	6,039,585
2015Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	38,561	5,201,809
2016Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	34,481	5,080,877
2017Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	33,482	4,774,136
2013Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	4,292	293,523
2014Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,740	189,260
2015Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,837	141,776
2016Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	5,146	234,119
2017Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	5,574	397,965
2013Y	Black Hills Power, Inc.	Black Hills Corporation	19,144	1,801,857
2014Y	Black Hills Power, Inc.	Black Hills Corporation	17,967	1,636,045
2015Y	Black Hills Power, Inc.	Black Hills Corporation	17,920	1,618,688
2016Y	Black Hills Power, Inc.	Black Hills Corporation	18,233	1,585,870
2017Y	Black Hills Power, Inc.	Black Hills Corporation	21,366	1,581,915

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	6,409	688,318
2014Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	7,053	709,754
2015Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	9,286	739,277
2016Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	8,334	805,351
2017Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	9,353	798,024
2013Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	16,049	780,810
2014Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	16,489	780,329
2015Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	15,524	835,606
2016Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	15,537	743,271
2017Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	17,461	799,127
2013Y	Cleco Power LLC	Cleco Partners LP	75,683	9,735,902
2014Y	Cleco Power LLC	Cleco Partners LP	89,393	9,857,122
2015Y	Cleco Power LLC	Cleco Partners LP	82,444	12,564,036
2016Y	Cleco Power LLC	Cleco Partners LP	89,044	12,758,553
2017Y	Cleco Power LLC	Cleco Partners LP	84,807	12,046,771
2013Y	Consumers Energy Company	CMS Energy Corporation	149,242	17,702,210
2014Y	Consumers Energy Company	CMS Energy Corporation	154,767	18,112,590
2015Y	Consumers Energy Company	CMS Energy Corporation	153,579	19,938,691
2016Y	Consumers Energy Company	CMS Energy Corporation	146,477	16,332,123
2017Y	Consumers Energy Company	CMS Energy Corporation	128,401	15,747,196
2013Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	142,781	3,184,924
2014Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	146,111	2,754,825
2015Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	164,824	2,928,723
2016Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	157,574	3,082,866
2017Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	126,729	3,095,750

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Virginia Electric and Power Company	Dominion Energy, Inc.	666,709	67,211,779
2014Y	Virginia Electric and Power Company	Dominion Energy, Inc.	1,244,953	67,367,785
2015Y	Virginia Electric and Power Company	Dominion Energy, Inc.	835,540	71,449,993
2016Y	Virginia Electric and Power Company	Dominion Energy, Inc.	983,460	80,237,294
2017Y	Virginia Electric and Power Company	Dominion Energy, Inc.	718,254	74,067,743
2013Y	DTE Electric Company	DTE Energy Company	467,019	41,690,842
2014Y	DTE Electric Company	DTE Energy Company	473,232	40,855,473
2015Y	DTE Electric Company	DTE Energy Company	490,020	40,938,409
2016Y	DTE Electric Company	DTE Energy Company	555,782	37,652,486
2017Y	DTE Electric Company	DTE Energy Company	472,467	38,807,840
2013Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	814,070	83,727,269
2014Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	927,885	83,053,146
2015Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	967,351	82,652,210
2016Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	938,315	82,895,355
2017Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	862,540	81,700,915
2013Y	Duke Energy Florida, LLC	Duke Energy Corporation	198,702	33,858,740
2014Y	Duke Energy Florida, LLC	Duke Energy Corporation	224,282	34,758,994
2015Y	Duke Energy Florida, LLC	Duke Energy Corporation	227,289	35,018,629
2016Y	Duke Energy Florida, LLC	Duke Energy Corporation	215,910	33,756,279
2017Y	Duke Energy Florida, LLC	Duke Energy Corporation	203,837	36,107,645
2013Y	Duke Energy Indiana, LLC	Duke Energy Corporation	238,332	26,184,912
2014Y	Duke Energy Indiana, LLC	Duke Energy Corporation	296,486	26,115,488
2015Y	Duke Energy Indiana, LLC	Duke Energy Corporation	342,983	26,231,251
2016Y	Duke Energy Indiana, LLC	Duke Energy Corporation	334,891	27,097,612
2017Y	Duke Energy Indiana, LLC	Duke Energy Corporation	310,442	27,580,105

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	38,223	3,682,139
2014Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	44,932	3,056,643
2015Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	41,299	4,454,859
2016Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	41,793	3,698,956
2017Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	38,495	4,282,897
2013Y	Duke Energy Progress, LLC	Duke Energy Corporation	714,642	55,806,705
2014Y	Duke Energy Progress, LLC	Duke Energy Corporation	778,772	59,570,127
2015Y	Duke Energy Progress, LLC	Duke Energy Corporation	838,358	61,853,417
2016Y	Duke Energy Progress, LLC	Duke Energy Corporation	769,221	64,286,169
2017Y	Duke Energy Progress, LLC	Duke Energy Corporation	700,775	61,393,565
2013Y	Southern California Edison Company	Edison International	575,021	16,999,633
2014Y	Southern California Edison Company	Edison International	292,094	13,103,742
2015Y	Southern California Edison Company	Edison International	198,912	12,161,063
2016Y	Southern California Edison Company	Edison International	210,774	14,005,004
2017Y	Southern California Edison Company	Edison International	202,975	15,255,081
2013Y	El Paso Electric Company	El Paso Electric Company	108,855	9,288,773
2014Y	El Paso Electric Company	El Paso Electric Company	115,882	9,477,129
2015Y	El Paso Electric Company	El Paso Electric Company	121,637	9,585,089
2016Y	El Paso Electric Company	El Paso Electric Company	121,772	8,820,006
2017Y	El Paso Electric Company	El Paso Electric Company	123,198	8,950,875
2013Y	Tampa Electric Company	Emera Incorporated	127,725	18,430,621
2014Y	Tampa Electric Company	Emera Incorporated	139,500	18,695,497
2015Y	Tampa Electric Company	Emera Incorporated	148,732	19,016,690
2016Y	Tampa Electric Company	Emera Incorporated	153,589	17,612,374
2017Y	Tampa Electric Company	Emera Incorporated	135,729	19,743,413

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2014Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2015Y	EL Investment Company, LLC	Entergy Corporation	182,161	21,874,272
2016Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2017Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2013Y	Entergy Arkansas, Inc.	Entergy Corporation	266,433	22,758,419
2014Y	Entergy Arkansas, Inc.	Entergy Corporation	281,655	25,879,393
2015Y	Entergy Arkansas, Inc.	Entergy Corporation	340,169	24,171,905
2016Y	Entergy Arkansas, Inc.	Entergy Corporation	346,461	26,435,825
2017Y	Entergy Arkansas, Inc.	Entergy Corporation	374,419	26,473,510
2013Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	182,715	12,584,706
2014Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	185,752	13,756,820
2015Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	139,861	8,601,727
2016Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA
2017Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA
2013Y	Entergy Louisiana, LLC	Entergy Corporation	217,860	19,249,674
2014Y	Entergy Louisiana, LLC	Entergy Corporation	227,387	21,969,765
2015Y	Entergy Louisiana, LLC	Entergy Corporation	106,279	8,737,102
2016Y	Entergy Louisiana, LLC	Entergy Corporation	440,050	45,088,889
2017Y	Entergy Louisiana, LLC	Entergy Corporation	459,538	40,856,135
2013Y	Entergy Mississippi, Inc.	Entergy Corporation	85,100	9,837,710
2014Y	Entergy Mississippi, Inc.	Entergy Corporation	72,995	8,859,920
2015Y	Entergy Mississippi, Inc.	Entergy Corporation	80,361	7,528,743
2016Y	Entergy Mississippi, Inc.	Entergy Corporation	70,690	9,815,419
2017Y	Entergy Mississippi, Inc.	Entergy Corporation	59,654	8,681,156

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Entergy New Orleans, LLC	Entergy Corporation	29,487	1,499,897
2014Y	Entergy New Orleans, LLC	Entergy Corporation	20,000	2,003,162
2015Y	Entergy New Orleans, LLC	Entergy Corporation	14,282	1,741,898
2016Y	Entergy New Orleans, LLC	Entergy Corporation	17,455	1,798,574
2017Y	Entergy New Orleans, LLC	Entergy Corporation	10,213	2,675,414
2013Y	Entergy Texas, Inc.	Entergy Corporation	56,402	7,033,780
2014Y	Entergy Texas, Inc.	Entergy Corporation	56,065	7,587,861
2015Y	Entergy Texas, Inc.	Entergy Corporation	58,171	8,620,430
2016Y	Entergy Texas, Inc.	Entergy Corporation	47,088	9,018,687
2017Y	Entergy Texas, Inc.	Entergy Corporation	52,757	6,674,690
2013Y	System Energy Resources, Inc.	Entergy Corporation	150,616	9,793,557
2014Y	System Energy Resources, Inc.	Entergy Corporation	142,437	9,218,542
2015Y	System Energy Resources, Inc.	Entergy Corporation	135,312	10,546,906
2016Y	System Energy Resources, Inc.	Entergy Corporation	133,344	5,383,560
2017Y	System Energy Resources, Inc.	Entergy Corporation	190,572	6,675,148
2013Y	Public Service Company of New Hampshire	Eversource Energy	45,816	2,273,034
2014Y	Public Service Company of New Hampshire	Eversource Energy	47,989	2,089,723
2015Y	Public Service Company of New Hampshire	Eversource Energy	53,638	1,705,611
2016Y	Public Service Company of New Hampshire	Eversource Energy	45,898	1,054,234
2017Y	Public Service Company of New Hampshire	Eversource Energy	45,860	968,784
2013Y	Western Massachusetts Electric Company	Eversource Energy	99	5,083
2014Y	Western Massachusetts Electric Company	Eversource Energy	214	7,972
2015Y	Western Massachusetts Electric Company	Eversource Energy	247	9,788
2016Y	Western Massachusetts Electric Company	Eversource Energy	221	9,979
2017Y	Western Massachusetts Electric Company	Eversource Energy	213	8,185

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Jersey Central Power & Light Company	FirstEnergy Corp.	1,517	-101,063
2014Y	Jersey Central Power & Light Company	FirstEnergy Corp.	1,567	-109,334
2015Y	Jersey Central Power & Light Company	FirstEnergy Corp.	2,398	-84,808
2016Y	Jersey Central Power & Light Company	FirstEnergy Corp.	2,926	-102,007
2017Y	Jersey Central Power & Light Company	FirstEnergy Corp.	2,394	-80,912
2013Y	Monongahela Power Company	FirstEnergy Corp.	69,442	9,074,125
2014Y	Monongahela Power Company	FirstEnergy Corp.	92,664	15,719,060
2015Y	Monongahela Power Company	FirstEnergy Corp.	93,540	14,764,770
2016Y	Monongahela Power Company	FirstEnergy Corp.	105,784	15,831,509
2017Y	Monongahela Power Company	FirstEnergy Corp.	104,487	15,555,045
2013Y	Ohio Edison Company	FirstEnergy Corp.	170,891	2,755,437
2014Y	Ohio Edison Company	FirstEnergy Corp.	172,600	2,892,102
2015Y	Ohio Edison Company	FirstEnergy Corp.	179,034	2,764,502
2016Y	Ohio Edison Company	FirstEnergy Corp.	126,484	2,224,648
2017Y	Ohio Edison Company	FirstEnergy Corp.	48,383	565,101
2013Y	Potomac Edison Company	FirstEnergy Corp.	179,814	3,780,302
2014Y	Potomac Edison Company	FirstEnergy Corp.	199,370	3,799,291
2015Y	Potomac Edison Company	FirstEnergy Corp.	183,910	3,760,799
2016Y	Potomac Edison Company	FirstEnergy Corp.	192,313	3,736,822
2017Y	Potomac Edison Company	FirstEnergy Corp.	180,150	3,613,698
2013Y	Toledo Edison Company	FirstEnergy Corp.	39,384	1,427,675
2014Y	Toledo Edison Company	FirstEnergy Corp.	45,186	1,329,312
2015Y	Toledo Edison Company	FirstEnergy Corp.	47,087	1,324,871
2016Y	Toledo Edison Company	FirstEnergy Corp.	40,562	1,436,777
2017Y	Toledo Edison Company	FirstEnergy Corp.	23,241	476,397

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	916	50,993
2014Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,007	40,156
2015Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,015	49,892
2016Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,040	41,963
2017Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	1,125	51,831
2013Y	Tucson Electric Power Company	Fortis Inc.	209,776	11,311,182
2014Y	Tucson Electric Power Company	Fortis Inc.	217,090	10,508,451
2015Y	Tucson Electric Power Company	Fortis Inc.	179,879	11,371,377
2016Y	Tucson Electric Power Company	Fortis Inc.	173,377	11,673,449
2017Y	Tucson Electric Power Company	Fortis Inc.	178,733	10,850,165
2013Y	UNS Electric, Inc.	Fortis Inc.	1,643	75,596
2014Y	UNS Electric, Inc.	Fortis Inc.	2,129	54,249
2015Y	UNS Electric, Inc.	Fortis Inc.	2,514	596,970
2016Y	UNS Electric, Inc.	Fortis Inc.	1,903	650,866
2017Y	UNS Electric, Inc.	Fortis Inc.	3,436	652,183
2013Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	189,884	21,070,448
2014Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	193,296	20,592,086
2015Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	182,519	18,769,964
2016Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	187,109	18,252,675
2017Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	179,727	17,751,489
2013Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	42,115	6,093,922
2014Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	41,437	4,506,287
2015Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	45,251	4,887,005
2016Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	48,570	3,939,139
2017Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	46,413	4,036,362

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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	3,005	9,300,489
2014Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,454	9,176,919
2015Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,500	9,077,689
2016Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,482	9,325,919
2017Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	2,402	9,120,870
2013Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	4,381	4,897,339
2014Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,483	4,849,285
2015Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,673	4,869,129
2016Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,641	4,811,403
2017Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	3,384	4,710,492
2013Y	Idaho Power Co.	IDACORP, Inc.	86,431	13,559,726
2014Y	Idaho Power Co.	IDACORP, Inc.	86,811	13,195,369
2015Y	Idaho Power Co.	IDACORP, Inc.	90,116	12,662,017
2016Y	Idaho Power Co.	IDACORP, Inc.	90,883	12,174,712
2017Y	Idaho Power Co.	IDACORP, Inc.	91,581	13,687,382
2013Y	Kentucky Utilities Company	LKE	126,521	19,938,878
2014Y	Kentucky Utilities Company	LKE	151,052	19,603,077
2015Y	Kentucky Utilities Company	LKE	164,471	20,956,533
2016Y	Kentucky Utilities Company	LKE	158,852	21,021,762
2017Y	Kentucky Utilities Company	LKE	157,247	19,702,882
2013Y	Louisville Gas and Electric Company	LKE	121,061	14,346,331
2014Y	Louisville Gas and Electric Company	LKE	121,235	15,117,891
2015Y	Louisville Gas and Electric Company	LKE	115,873	13,054,267
2016Y	Louisville Gas and Electric Company	LKE	99,121	12,908,109
2017Y	Louisville Gas and Electric Company	LKE	97,987	13,001,377

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	24,544	2,430,001
2014Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	25,377	2,519,938
2015Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	28,437	1,898,159
2016Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	33,014	2,626,763
2017Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	34,605	2,630,640
2013Y	Madison Gas and Electric Company	MGE Energy, Inc.	25,055	2,177,419
2014Y	Madison Gas and Electric Company	MGE Energy, Inc.	24,649	1,879,109
2015Y	Madison Gas and Electric Company	MGE Energy, Inc.	24,651	2,079,432
2016Y	Madison Gas and Electric Company	MGE Energy, Inc.	25,498	2,515,643
2017Y	Madison Gas and Electric Company	MGE Energy, Inc.	23,378	2,311,261
2013Y	National Grid Generation, LLC	National Grid plc	91,178	4,823,499
2014Y	National Grid Generation, LLC	National Grid plc	81,808	4,558,386
2015Y	National Grid Generation, LLC	National Grid plc	99,044	5,050,928
2016Y	National Grid Generation, LLC	National Grid plc	103,969	4,561,590
2017Y	National Grid Generation, LLC	National Grid plc	91,411	3,213,471
2013Y	Florida Power & Light Company	NextEra Energy, Inc.	651,527	106,695,382
2014Y	Florida Power & Light Company	NextEra Energy, Inc.	632,335	110,932,638
2015Y	Florida Power & Light Company	NextEra Energy, Inc.	655,886	118,641,462
2016Y	Florida Power & Light Company	NextEra Energy, Inc.	643,878	119,083,556
2017Y	Florida Power & Light Company	NextEra Energy, Inc.	628,288	119,906,645
2013Y	Northern Indiana Public Service Company	NiSource Inc.	164,651	14,177,379
2014Y	Northern Indiana Public Service Company	NiSource Inc.	175,209	14,788,291
2015Y	Northern Indiana Public Service Company	NiSource Inc.	182,919	12,204,874
2016Y	Northern Indiana Public Service Company	NiSource Inc.	211,800	12,113,507
2017Y	Northern Indiana Public Service Company	NiSource Inc.	233,456	12,018,749

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	NorthWestern Corporation	NorthWestern Corporation	25,594	3,183,893
2014Y	NorthWestern Corporation	NorthWestern Corporation	34,844	3,826,738
2015Y	NorthWestern Corporation	NorthWestern Corporation	57,721	6,588,168
2016Y	NorthWestern Corporation	NorthWestern Corporation	47,994	5,333,204
2017Y	NorthWestern Corporation	NorthWestern Corporation	50,120	5,495,976
2013Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	122,705	24,161,327
2014Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	125,035	22,806,874
2015Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	119,512	20,880,561
2016Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	122,547	21,407,776
2017Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	121,907	18,507,115
2013Y	Otter Tail Power Company	Otter Tail Corporation	27,024	3,718,922
2014Y	Otter Tail Power Company	Otter Tail Corporation	32,535	3,511,423
2015Y	Otter Tail Power Company	Otter Tail Corporation	30,547	2,305,968
2016Y	Otter Tail Power Company	Otter Tail Corporation	31,649	2,821,779
2017Y	Otter Tail Power Company	Otter Tail Corporation	31,100	2,931,645
2013Y	Pacific Gas and Electric Company	PG&E Corporation	622,080	31,439,918
2014Y	Pacific Gas and Electric Company	PG&E Corporation	591,994	28,808,501
2015Y	Pacific Gas and Electric Company	PG&E Corporation	675,716	30,374,207
2016Y	Pacific Gas and Electric Company	PG&E Corporation	693,646	32,963,113
2017Y	Pacific Gas and Electric Company	PG&E Corporation	589,784	34,514,059
2013Y	Arizona Public Service Company	Pinnacle West Capital Corporation	416,257	26,178,855
2014Y	Arizona Public Service Company	Pinnacle West Capital Corporation	438,186	26,987,843
2015Y	Arizona Public Service Company	Pinnacle West Capital Corporation	438,805	27,442,278
2016Y	Arizona Public Service Company	Pinnacle West Capital Corporation	406,108	24,835,334
2017Y	Arizona Public Service Company	Pinnacle West Capital Corporation	414,065	24,920,924

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Public Service Company of New Mexico	PNM Resources, Inc.	181,117	10,417,604
2014Y	Public Service Company of New Mexico	PNM Resources, Inc.	190,525	10,172,236
2015Y	Public Service Company of New Mexico	PNM Resources, Inc.	180,839	10,054,663
2016Y	Public Service Company of New Mexico	PNM Resources, Inc.	141,433	10,356,219
2017Y	Public Service Company of New Mexico	PNM Resources, Inc.	132,281	10,247,953
2013Y	Portland General Electric Company	Portland General Electric Company	98,303	10,290,898
2014Y	Portland General Electric Company	Portland General Electric Company	115,252	10,817,321
2015Y	Portland General Electric Company	Portland General Electric Company	122,543	12,152,016
2016Y	Portland General Electric Company	Portland General Electric Company	126,752	12,844,073
2017Y	Portland General Electric Company	Portland General Electric Company	135,641	12,987,082
2013Y	Puget Sound Energy, Inc.	Puget Holdings LLC	116,054	12,421,625
2014Y	Puget Sound Energy, Inc.	Puget Holdings LLC	112,835	11,640,503
2015Y	Puget Sound Energy, Inc.	Puget Holdings LLC	117,453	12,747,014
2016Y	Puget Sound Energy, Inc.	Puget Holdings LLC	126,238	11,577,608
2017Y	Puget Sound Energy, Inc.	Puget Holdings LLC	125,003	10,825,779
2013Y	South Carolina Electric & Gas Co.	SCANA Corporation	187,531	19,200,991
2014Y	South Carolina Electric & Gas Co.	SCANA Corporation	184,994	19,524,528
2015Y	South Carolina Electric & Gas Co.	SCANA Corporation	184,858	19,360,639
2016Y	South Carolina Electric & Gas Co.	SCANA Corporation	189,161	19,602,810
2017Y	South Carolina Electric & Gas Co.	SCANA Corporation	193,840	19,260,566
2013Y	South Carolina Generating Company, Inc.	SCANA Corporation	9,744	3,343,690
2014Y	South Carolina Generating Company, Inc.	SCANA Corporation	13,228	3,702,495
2015Y	South Carolina Generating Company, Inc.	SCANA Corporation	10,794	3,734,928
2016Y	South Carolina Generating Company, Inc.	SCANA Corporation	16,496	2,991,906
2017Y	South Carolina Generating Company, Inc.	SCANA Corporation	17,948	2,606,561

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	San Diego Gas & Electric Co.	Sempra Energy	351,746	6,709,651
2014Y	San Diego Gas & Electric Co.	Sempra Energy	98,921	4,197,493
2015Y	San Diego Gas & Electric Co.	Sempra Energy	46,228	5,278,816
2016Y	San Diego Gas & Electric Co.	Sempra Energy	44,657	3,654,442
2017Y	San Diego Gas & Electric Co.	Sempra Energy	40,121	3,692,211
2013Y	Alabama Power Company	Southern Company	553,407	65,251,725
2014Y	Alabama Power Company	Southern Company	676,877	63,573,171
2015Y	Alabama Power Company	Southern Company	671,108	60,914,065
2016Y	Alabama Power Company	Southern Company	693,994	60,196,690
2017Y	Alabama Power Company	Southern Company	737,698	60,332,669
2013Y	Georgia Power Company	Southern Company	590,054	66,795,159
2014Y	Georgia Power Company	Southern Company	706,854	69,927,957
2015Y	Georgia Power Company	Southern Company	850,183	65,863,498
2016Y	Georgia Power Company	Southern Company	692,145	68,386,979
2017Y	Georgia Power Company	Southern Company	598,495	63,184,997
2013Y	Gulf Power Company	Southern Company	105,051	14,532,685
2014Y	Gulf Power Company	Southern Company	132,376	15,627,445
2015Y	Gulf Power Company	Southern Company	130,188	12,688,716
2016Y	Gulf Power Company	Southern Company	124,416	13,444,878
2017Y	Gulf Power Company	Southern Company	132,590	13,980,828
2013Y	Mississippi Power Company	Southern Company	121,325	13,721,052
2014Y	Mississippi Power Company	Southern Company	123,594	16,880,783
2015Y	Mississippi Power Company	Southern Company	103,186	17,013,730
2016Y	Mississippi Power Company	Southern Company	113,417	14,513,729
2017Y	Mississippi Power Company	Southern Company	107,505	15,318,941

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Southern Electric Generating Company	Southern Company	64,604	2,107,334
2014Y	Southern Electric Generating Company	Southern Company	49,878	2,084,739
2015Y	Southern Electric Generating Company	Southern Company	67,845	1,277,061
2016Y	Southern Electric Generating Company	Southern Company	41,092	394,540
2017Y	Southern Electric Generating Company	Southern Company	43,130	1,406,811
2013Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	73,907	5,279,210
2014Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	77,206	5,546,416
2015Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	69,734	4,881,762
2016Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	68,618	4,137,855
2017Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	64,362	4,578,393
2013Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	617,794	22,248,923
2014Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	603,415	22,993,274
2015Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	654,057	26,300,661
2016Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	670,262	26,108,967
2017Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	671,635	25,244,017
2013Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	90,756	10,803,149
2014Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	103,011	9,474,337
2015Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	89,441	10,285,397
2016Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	75,384	9,622,632
2017Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	76,410	10,479,257
2013Y	Kansas Gas and Electric Company	Westar Energy, Inc.	155,715	10,348,490
2014Y	Kansas Gas and Electric Company	Westar Energy, Inc.	158,083	10,621,890
2015Y	Kansas Gas and Electric Company	Westar Energy, Inc.	144,822	10,055,647
2016Y	Kansas Gas and Electric Company	Westar Energy, Inc.	148,087	10,169,665
2017Y	Kansas Gas and Electric Company	Westar Energy, Inc.	140,840	9,430,777

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Westar Energy (KPL)	Westar Energy, Inc.	86,267	15,175,161
2014Y	Westar Energy (KPL)	Westar Energy, Inc.	94,279	14,094,928
2015Y	Westar Energy (KPL)	Westar Energy, Inc.	86,642	12,386,653
2016Y	Westar Energy (KPL)	Westar Energy, Inc.	89,882	10,809,012
2017Y	Westar Energy (KPL)	Westar Energy, Inc.	91,347	12,569,839
2013Y	Westar Generating, Inc.	Westar Energy, Inc.	3,973	735,166
2014Y	Westar Generating, Inc.	Westar Energy, Inc.	4,027	608,351
2015Y	Westar Generating, Inc.	Westar Energy, Inc.	6,024	690,492
2016Y	Westar Generating, Inc.	Westar Energy, Inc.	4,761	945,870
2017Y	Westar Generating, Inc.	Westar Energy, Inc.	5,144	983,635
2013Y	Wisconsin River Power Company	Wisconsin River Power Company	2,153	20
2014Y	Wisconsin River Power Company	Wisconsin River Power Company	1,994	222,969
2015Y	Wisconsin River Power Company	Wisconsin River Power Company	1,971	204,110
2016Y	Wisconsin River Power Company	Wisconsin River Power Company	1,842	248,314
2017Y	Wisconsin River Power Company	Wisconsin River Power Company	1,937	44,527
2013Y	Northern States Power Company - MN	Xcel Energy Inc.	539,629	28,125,265
2014Y	Northern States Power Company - MN	Xcel Energy Inc.	575,094	32,158,328
2015Y	Northern States Power Company - MN	Xcel Energy Inc.	546,532	32,795,074
2016Y	Northern States Power Company - MN	Xcel Energy Inc.	541,210	35,430,974
2017Y	Northern States Power Company - MN	Xcel Energy Inc.	509,376	35,236,652
2013Y	Northern States Power Company - WI	Xcel Energy Inc.	21,350	1,114,444
2014Y	Northern States Power Company - WI	Xcel Energy Inc.	21,835	1,298,677
2015Y	Northern States Power Company - WI	Xcel Energy Inc.	20,208	1,240,211
2016Y	Northern States Power Company - WI	Xcel Energy Inc.	19,519	1,405,845
2017Y	Northern States Power Company - WI	Xcel Energy Inc.	20,257	1,408,854

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Non Fuel O&M ($000)	Net Generation (MWh)
2013Y	Public Service Company of Colorado	Xcel Energy Inc.	185,844	22,245,725
2014Y	Public Service Company of Colorado	Xcel Energy Inc.	182,309	22,429,819
2015Y	Public Service Company of Colorado	Xcel Energy Inc.	181,422	22,654,375
2016Y	Public Service Company of Colorado	Xcel Energy Inc.	169,248	21,983,880
2017Y	Public Service Company of Colorado	Xcel Energy Inc.	157,317	22,420,317
2013Y	Southwestern Public Service Company	Xcel Energy Inc.	94,795	18,813,781
2014Y	Southwestern Public Service Company	Xcel Energy Inc.	97,876	16,953,285
2015Y	Southwestern Public Service Company	Xcel Energy Inc.	105,699	16,476,374
2016Y	Southwestern Public Service Company	Xcel Energy Inc.	95,099	15,011,035
2017Y	Southwestern Public Service Company	Xcel Energy Inc.	90,072	12,857,693
		Total	81,032,738	7,571,163,978

Transmission Rankings [2013-2017]   Source: SNL

Holding Company	Trans O&M	Trans Plant: Add	O&M/Add	Total Sales of Elec. Volume (MWh)	Trans O&M and Plant/MWh	Ranking
NextEra Energy, Inc.	470,208,000	1,606,290,000	2,076,498,000	576,861,659	3.60	1
LKE	230,632,774	410,487,000	641,119,774	177,006,629	3.62	2
Duke Energy Corporation	1,298,444,000	3,684,202,000	4,982,646,000	1,280,342,802	3.89	3
Emera Incorporated	(24,210,000)	460,616,000	436,406,000	106,439,317	4.10	4
DQE Holdings LLC	51,933,000	237,235,000	289,168,000	67,127,889	4.31	5
El Paso Electric Company	95,162,000	139,751,000	234,913,000	54,312,529	4.33	6
Great Plains Energy Inc	535,891,000	166,885,000	702,776,000	149,872,607	4.69	7
Southern Company	1,163,844,000	3,204,912,000	4,368,756,000	923,010,412	4.73	8
IDACORP, Inc.	131,826,000	256,005,000	387,831,000	80,222,328	4.83	9
AES Corporation	575,413,000	186,295,000	761,708,000	157,380,054	4.84	10
Entergy Corporation	931,758,000	2,918,655,000	3,850,413,000	748,921,761	5.14	11
NiSource Inc.	187,120,000	267,405,000	454,525,000	85,969,484	5.29	12
Vectren Corporation	86,135,000	73,339,000	159,474,000	28,861,057	5.53	13
Avista Corporation	158,299,000	203,734,000	362,033,000	63,822,212	5.67	14
Portland General Electric Co	482,870,000	130,372,000	613,242,000	105,742,391	5.80	15
FirstEnergy Corp.	3,673,002,000	1,047,540,000	4,720,542,000	795,797,359	5.93	16
Cleco Partners LP	152,471,000	199,772,000	352,243,000	58,299,323	6.04	17
Ameren Corporation	628,087,000	1,856,827,000	2,484,914,000	396,912,264	6.26	18
Consolidated Edison, Inc.	852,287,000	955,858,000	1,808,145,000	264,071,298	6.85	19
SCANA Corporation	99,091,000	691,077,000	790,168,000	115,124,628	6.86	20
Berkshire Hathaway Inc.	1,680,844,000	2,794,833,000	4,475,677,000	647,595,062	6.91	21
DTE Energy Company	1,574,116,000	19,521,000	1,593,637,000	230,365,093	6.92	22
Pinnacle West Capital Corp	399,387,000	724,709,000	1,124,096,000	161,506,003	6.96	23
Puget Holdings LLC	647,511,000	338,611,000	986,122,000	132,788,263	7.43	24
Exelon Corporation	2,910,302,000	4,775,914,000	7,686,216,000	1,034,415,389	7.43	25
WEC Energy Group, Inc.	2,021,674,000	0	2,021,674,000	247,141,624	8.18	26

Transmission Rankings [2013-2017]   Source: SNL

Holding Company	Trans O&M	Trans Plant: Add	O&M/Add	Total Sales of Elec. Volume (MWh)	Trans O&M and Plant/MWh	Ranking
Fortis Inc.	252,060,000	491,047,000	743,107,000	90,696,008	8.19	27
PNM Resources, Inc.	186,004,000	314,857,000	500,861,000	60,114,213	8.33	28
Mt. Carmel Public Utility Company	3,927,000	500,000	4,427,000	490,041	9.03	29
AEP	4,814,898,000	4,339,738,000	9,154,636,000	1,006,249,397	9.10	30
CMS Energy Corporation	1,708,673,000	10,970,000	1,719,643,000	180,393,075	9.53	31
NorthWestern Corporation	159,692,000	304,552,000	464,244,000	48,516,397	9.57	32
UGI Corporation	35,791,000	11,363,000	47,154,000	4,900,628	9.62	33
ALLETE, Inc.	367,745,000	354,615,000	722,360,000	74,330,795	9.72	34
MGE Energy, Inc.	180,569,000	0	180,569,000	17,944,098	10.06	35
Dominion Energy, Inc.	255,160,000	4,177,001,000	4,432,161,000	424,814,207	10.43	36
Algonquin Power & Utilities Corp.	209,862,000	118,961,000	328,823,000	29,685,318	11.08	37
CenterPoint Energy, Inc.	3,669,934,000	1,002,773,000	4,672,707,000	421,479,989	11.09	38
Black Hills Corporation	231,608,000	155,491,000	387,099,000	32,232,125	12.01	39
OGE Energy Corp.	702,763,000	1,131,294,000	1,834,057,000	145,554,088	12.60	40
Xcel Energy Inc.	2,883,666,000	3,955,601,000	6,839,267,000	541,441,613	12.63	41
PG&E Corporation	1,354,096,000	4,196,915,000	5,551,011,000	437,736,683	12.68	42
Balfour Beatty Infrastructure	54,359,000	0	54,359,000	4,147,629	13.11	43
Sempra Energy	4,726,642,000	4,950,386,000	9,677,028,000	732,367,419	13.21	44
MDU Resources Group, Inc.	109,043,000	118,347,000	227,390,000	16,493,138	13.79	45
Westar Energy, Inc.	1,232,121,000	813,574,000	2,045,695,000	146,818,676	13.93	46
Otter Tail Corporation	133,895,000	245,131,000	379,026,000	26,396,332	14.36	47
Alliant Energy Corporation	2,386,205,000	0	2,386,205,000	158,149,961	15.09	48
Edison International	1,321,030,000	6,356,016,000	7,677,046,000	476,972,294	16.10	49
PPL Corporation	673,785,000	3,141,828,000	3,815,613,000	188,245,085	20.27	50
Unitil Corporation	169,352,000	5,835,000	175,187,000	8,513,641	20.58	51
Eversource Energy	2,780,588,000	3,643,701,000	6,424,289,000	289,678,343	22.18	52

Transmission Rankings [2013-2017] Source: SNL

Holding Company	Trans O&M	Trans Plant: Add	O&M/Add	Total Sales of Elec. Volume (MWh)	Trans O&M and Plant/MWh	Ranking
Caisse de dépôt et	472,684,000	87,678,000	560,362,000	23,640,213	23.70	53
Iberdrola, S.A.	1,802,783,000	2,071,448,000	3,874,231,000	157,875,239	24.54	54
Public Service Enterprise Group Inc	484,909,000	7,771,207,000	8,256,116,000	213,547,903	38.66	55
National Grid plc	3,241,295,000	2,506,882,000	5,748,177,000	138,240,421	41.58	56
Grand Total	57,619,236,774	79,628,556,000	137,247,792,774	14,787,574,406		

Q1	5.77
Q2	8.68
Q3	12.79
Industry Avg.	9.28

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Dayton Power and Light Company	AES Corporation	104,155	10,744	19,416,290
2014Y	Dayton Power and Light Company	AES Corporation	128,326	14,488	18,643,195
2015Y	Dayton Power and Light Company	AES Corporation	91,016	14,497	16,433,036
2016Y	Dayton Power and Light Company	AES Corporation	79,455	4,955	16,158,129
2017Y	Dayton Power and Light Company	AES Corporation	70,510	-1,003	12,236,126
2013Y	Indianapolis Power & Light Company	AES Corporation	11,831	8,988	16,033,922
2014Y	Indianapolis Power & Light Company	AES Corporation	11,608	12,609	16,391,321
2015Y	Indianapolis Power & Light Company	AES Corporation	10,254	28,160	14,397,561
2016Y	Indianapolis Power & Light Company	AES Corporation	27,979	88,063	14,185,985
2017Y	Indianapolis Power & Light Company	AES Corporation	40,279	4,794	13,484,489
2013Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	17,333	12,298	5,620,276
2014Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	22,681	26,146	5,131,750
2015Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	23,667	33,097	4,940,028
2016Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	22,089	23,996	4,950,707
2017Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	25,026	23,424	4,841,355
2013Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	16,964	0	552,273
2014Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	19,771	0	910,825
2015Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	19,673	0	933,262
2016Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	20,904	0	910,242
2017Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	21,754	0	894,600
2013Y	ALLETE (Minnesota Power)	ALLETE, Inc.	52,185	73,786	13,264,062
2014Y	ALLETE (Minnesota Power)	ALLETE, Inc.	64,818	101,995	13,942,499
2015Y	ALLETE (Minnesota Power)	ALLETE, Inc.	73,534	85,769	14,369,559
2016Y	ALLETE (Minnesota Power)	ALLETE, Inc.	84,273	36,978	14,147,335
2017Y	ALLETE (Minnesota Power)	ALLETE, Inc.	92,281	47,055	14,692,658
2013Y	Superior Water, Light and Power Company	ALLETE, Inc.	267	311	687,209
2014Y	Superior Water, Light and Power Company	ALLETE, Inc.	94	34	770,427
2015Y	Superior Water, Light and Power Company	ALLETE, Inc.	90	5,641	788,342
2016Y	Superior Water, Light and Power Company	ALLETE, Inc.	77	2,370	820,880
2017Y	Superior Water, Light and Power Company	ALLETE, Inc.	126	676	847,824
2013Y	Interstate Power and Light Company	Alliant Energy Corporation	304,456	0	17,194,056
2014Y	Interstate Power and Light Company	Alliant Energy Corporation	326,345	0	16,871,181

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Interstate Power and Light Company	Alliant Energy Corporation	330,867	0	16,703,172
2016Y	Interstate Power and Light Company	Alliant Energy Corporation	362,583	0	16,662,731
2017Y	Interstate Power and Light Company	Alliant Energy Corporation	313,416	0	17,406,995
2013Y	Wisconsin Power and Light Company	Alliant Energy Corporation	119,246	0	14,862,652
2014Y	Wisconsin Power and Light Company	Alliant Energy Corporation	126,553	0	14,603,712
2015Y	Wisconsin Power and Light Company	Alliant Energy Corporation	159,341	0	15,199,013
2016Y	Wisconsin Power and Light Company	Alliant Energy Corporation	170,460	0	14,480,783
2017Y	Wisconsin Power and Light Company	Alliant Energy Corporation	172,938	0	14,165,666
2013Y	Ameren Illinois Company	Ameren Corporation	42,345	197,815	38,012,834
2014Y	Ameren Illinois Company	Ameren Corporation	47,523	246,147	37,915,282
2015Y	Ameren Illinois Company	Ameren Corporation	53,565	310,717	36,850,871
2016Y	Ameren Illinois Company	Ameren Corporation	58,943	348,069	36,754,294
2017Y	Ameren Illinois Company	Ameren Corporation	59,555	295,663	35,537,431
2013Y	Union Electric Company	Ameren Corporation	58,896	69,923	43,158,138
2014Y	Union Electric Company	Ameren Corporation	60,321	130,206	43,192,724
2015Y	Union Electric Company	Ameren Corporation	70,144	27,111	43,255,846
2016Y	Union Electric Company	Ameren Corporation	80,459	175,520	39,997,209
2017Y	Union Electric Company	Ameren Corporation	96,336	55,656	42,237,635
2013Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2014Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	16,770	NA	47,215,732
2015Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2016Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2017Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2013Y	AEP Texas Central Company	American Electric Power Company, Inc.	159,143	115,815	NA
2014Y	AEP Texas Central Company	American Electric Power Company, Inc.	219,095	226,753	NA
2015Y	AEP Texas Central Company	American Electric Power Company, Inc.	242,609	229,635	NA
2016Y	AEP Texas Central Company	American Electric Power Company, Inc.	258,551	207,620	NA
2017Y	AEP Texas Central Company	American Electric Power Company, Inc.	NA	NA	NA
2013Y	AEP Texas North Company	American Electric Power Company, Inc.	50,657	32,878	2,435,181
2014Y	AEP Texas North Company	American Electric Power Company, Inc.	61,131	40,616	1,741,758
2015Y	AEP Texas North Company	American Electric Power Company, Inc.	67,217	58,836	1,368,742
2016Y	AEP Texas North Company	American Electric Power Company, Inc.	67,895	77,706	1,381,295

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2017Y	AEP Texas North Company	American Electric Power Company, Inc.	NA	NA	NA
2013Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2014Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2015Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2016Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2017Y	AEP Texas, Inc.	American Electric Power Company, Inc.	318,963	447,585	923,791
2013Y	Appalachian Power Company	American Electric Power Company, Inc.	76,711	114,954	47,596,529
2014Y	Appalachian Power Company	American Electric Power Company, Inc.	141,646	73,640	35,769,358
2015Y	Appalachian Power Company	American Electric Power Company, Inc.	143,949	191,186	34,847,578
2016Y	Appalachian Power Company	American Electric Power Company, Inc.	216,840	400,032	34,862,820
2017Y	Appalachian Power Company	American Electric Power Company, Inc.	232,090	247,993	33,601,395
2013Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	55,000	45,588	38,036,953
2014Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	83,059	61,566	35,331,017
2015Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	87,130	57,599	30,404,900
2016Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	98,318	84,043	28,379,413
2017Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	140,880	73,541	29,819,953
2013Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	471	75	5,475,276
2014Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	435	1,219	5,936,251
2015Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	505	12	5,186,234
2016Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	584	172	4,985,411
2017Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	550	1,293	6,032,062
2013Y	Kentucky Power Company	American Electric Power Company, Inc.	14,384	13,956	9,933,527
2014Y	Kentucky Power Company	American Electric Power Company, Inc.	22,065	50,613	11,993,933
2015Y	Kentucky Power Company	American Electric Power Company, Inc.	27,835	11,993	8,700,986
2016Y	Kentucky Power Company	American Electric Power Company, Inc.	34,927	8,095	7,276,047
2017Y	Kentucky Power Company	American Electric Power Company, Inc.	44,236	9,400	7,106,360
2013Y	Kingsport Power Company	American Electric Power Company, Inc.	553	5,023	2,045,738
2014Y	Kingsport Power Company	American Electric Power Company, Inc.	597	2,309	2,120,716
2015Y	Kingsport Power Company	American Electric Power Company, Inc.	557	1,262	2,086,994
2016Y	Kingsport Power Company	American Electric Power Company, Inc.	728	430	2,038,552
2017Y	Kingsport Power Company	American Electric Power Company, Inc.	794	6,819	1,971,080
2013Y	Ohio Power Company	American Electric Power Company, Inc.	39,545	84,418	60,639,578

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Ohio Power Company	American Electric Power Company, Inc.	148,146	115,183	15,591,760
2015Y	Ohio Power Company	American Electric Power Company, Inc.	180,334	152,162	45,685,751
2016Y	Ohio Power Company	American Electric Power Company, Inc.	212,281	98,200	45,870,876
2017Y	Ohio Power Company	American Electric Power Company, Inc.	244,905	118,181	45,688,514
2013Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	6,045	3,610	10,499,577
2014Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	6,202	157	11,400,464
2015Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	5,942	90	8,872,645
2016Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	5,991	2,345	9,919,829
2017Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	6,212	0	11,881,430
2013Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	76,921	28,080	19,239,394
2014Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	95,266	90,142	19,517,893
2015Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	100,058	31,677	18,916,965
2016Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	114,839	36,937	19,425,199
2017Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	137,834	37,675	19,052,676
2013Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	65,917	54,115	28,553,233
2014Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	80,473	130,887	28,644,882
2015Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	96,781	89,956	27,269,400
2016Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	120,301	203,397	26,169,526
2017Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	119,772	113,430	26,257,034
2013Y	Wheeling Power Company	American Electric Power Company, Inc.	1,129	24,076	2,703,781
2014Y	Wheeling Power Company	American Electric Power Company, Inc.	729	4,788	3,269,892
2015Y	Wheeling Power Company	American Electric Power Company, Inc.	9,901	12,955	4,451,364
2016Y	Wheeling Power Company	American Electric Power Company, Inc.	20,057	3,929	5,106,836
2017Y	Wheeling Power Company	American Electric Power Company, Inc.	32,442	3,091	5,015,316
2013Y	Alaska Electric Light and Power Company	Avista Corporation	524	638	377,005
2014Y	Alaska Electric Light and Power Company	Avista Corporation	556	752	422,784
2015Y	Alaska Electric Light and Power Company	Avista Corporation	470	503	398,066
2016Y	Alaska Electric Light and Power Company	Avista Corporation	623	1,518	395,154
2017Y	Alaska Electric Light and Power Company	Avista Corporation	718	1,227	414,210
2013Y	Avista Corporation	Avista Corporation	30,263	25,773	13,318,994
2014Y	Avista Corporation	Avista Corporation	31,164	40,768	12,839,533
2015Y	Avista Corporation	Avista Corporation	29,542	38,387	11,942,035

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Avista Corporation	Avista Corporation	31,090	44,250	11,733,626
2017Y	Avista Corporation	Avista Corporation	33,349	49,918	11,980,805
2013Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	7,891	0	881,022
2014Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	11,588	0	845,665
2015Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	18,269	0	844,127
2016Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	9,825	0	831,622
2017Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	6,786	0	745,193
2013Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	48,509	42,456	32,680,735
2014Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	53,065	69,965	32,499,927
2015Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	57,875	188,128	31,832,657
2016Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	67,180	434,244	32,475,023
2017Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	77,396	114,219	33,727,302
2013Y	Nevada Power Company	Berkshire Hathaway Inc.	32,532	150,632	24,064,426
2014Y	Nevada Power Company	Berkshire Hathaway Inc.	76,754	19,003	22,745,488
2015Y	Nevada Power Company	Berkshire Hathaway Inc.	47,215	33,403	25,481,621
2016Y	Nevada Power Company	Berkshire Hathaway Inc.	59,480	57,805	25,062,084
2017Y	Nevada Power Company	Berkshire Hathaway Inc.	59,167	17,999	23,751,206
2013Y	PacifiCorp	Berkshire Hathaway Inc.	198,670	521,412	65,869,008
2014Y	PacifiCorp	Berkshire Hathaway Inc.	211,058	178,957	65,269,524
2015Y	PacifiCorp	Berkshire Hathaway Inc.	215,664	528,249	63,530,663
2016Y	PacifiCorp	Berkshire Hathaway Inc.	203,261	153,285	60,958,902
2017Y	PacifiCorp	Berkshire Hathaway Inc.	204,806	192,361	62,468,319
2013Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	14,419	8,599	9,185,572
2014Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	11,772	14,704	8,882,408
2015Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	14,795	20,676	8,911,051
2016Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	14,406	32,635	9,000,293
2017Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	12,820	16,101	9,198,853
2013Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,720	9	2,028,643
2014Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	4,585	15,019	1,957,695
2015Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	5,445	5,287	1,959,505
2016Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	5,440	21,680	1,985,177
2017Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	6,140	9,157	1,932,972

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2013Y	Black Hills Power, Inc.	Black Hills Corporation	22,962	352	3,084,298
2014Y	Black Hills Power, Inc.	Black Hills Corporation	24,294	676	2,905,098
2015Y	Black Hills Power, Inc.	Black Hills Corporation	23,464	1,832	2,873,371
2016Y	Black Hills Power, Inc.	Black Hills Corporation	25,302	29,830	2,611,946
2017Y	Black Hills Power, Inc.	Black Hills Corporation	27,381	38,647	2,992,386
2013Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	14,351	3,650	1,635,140
2014Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	15,848	16,390	1,639,680
2015Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	15,775	5,587	1,418,697
2016Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	17,817	529	1,559,870
2017Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	19,084	6,846	1,647,647
2013Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	87,363	37,535	4,853,495
2014Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	92,767	17,076	4,713,347
2015Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	98,295	15,396	4,751,076
2016Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	95,650	7,639	4,688,744
2017Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	98,609	10,032	4,633,551
2013Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	534,401	99,927	79,984,965
2014Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	705,409	123,177	81,839,060
2015Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	751,683	175,440	84,190,647
2016Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	810,924	232,762	86,828,900
2017Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	867,517	371,467	88,636,417
2013Y	Cleco Power LLC	Cleco Partners LP	18,949	73,042	11,115,732
2014Y	Cleco Power LLC	Cleco Partners LP	29,412	15,642	12,201,940
2015Y	Cleco Power LLC	Cleco Partners LP	30,764	39,044	12,105,640
2016Y	Cleco Power LLC	Cleco Partners LP	37,925	58,318	11,596,427
2017Y	Cleco Power LLC	Cleco Partners LP	35,421	13,726	11,279,584
2013Y	Consumers Energy Company	CMS Energy Corporation	302,524	0	35,276,791
2014Y	Consumers Energy Company	CMS Energy Corporation	337,514	0	35,893,242
2015Y	Consumers Energy Company	CMS Energy Corporation	346,106	0	36,357,438
2016Y	Consumers Energy Company	CMS Energy Corporation	371,546	3,759	36,746,531
2017Y	Consumers Energy Company	CMS Energy Corporation	350,983	7,211	36,119,073
2013Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	149,148	148,675	47,335,320
2014Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	134,741	212,811	46,406,542

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2015Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	149,154	159,703	47,202,850
2016Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	161,227	196,177	47,450,242
2017Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	174,857	168,787	46,342,045
2013Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	12,915	4,061	4,263,699
2014Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	14,751	35,846	4,256,408
2015Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	13,950	6,390	4,415,840
2016Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	15,215	13,643	4,315,576
2017Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	15,667	5,969	4,056,841
2013Y	Rockland Electric Company	Consolidated Edison, Inc.	1,845	1,136	1,642,857
2014Y	Rockland Electric Company	Consolidated Edison, Inc.	2,907	1,759	1,610,904
2015Y	Rockland Electric Company	Consolidated Edison, Inc.	2,125	685	1,631,351
2016Y	Rockland Electric Company	Consolidated Edison, Inc.	1,573	1,598	1,601,861
2017Y	Rockland Electric Company	Consolidated Edison, Inc.	2,212	-1,382	1,538,962
2013Y	Virginia Electric and Power Company	Dominion Energy, Inc.	40,470	716,213	82,852,117
2014Y	Virginia Electric and Power Company	Dominion Energy, Inc.	22,275	953,331	83,938,195
2015Y	Virginia Electric and Power Company	Dominion Energy, Inc.	100,092	1,091,339	85,178,907
2016Y	Virginia Electric and Power Company	Dominion Energy, Inc.	99,432	938,411	87,875,099
2017Y	Virginia Electric and Power Company	Dominion Energy, Inc.	-7,109	477,707	84,969,889
2013Y	Duquesne Light Company	DQE Holdings LLC	9,486	59,055	14,007,273
2014Y	Duquesne Light Company	DQE Holdings LLC	8,900	34,580	13,747,339
2015Y	Duquesne Light Company	DQE Holdings LLC	10,096	16,684	13,503,863
2016Y	Duquesne Light Company	DQE Holdings LLC	10,747	99,207	13,172,591
2017Y	Duquesne Light Company	DQE Holdings LLC	12,704	27,709	12,696,823
2013Y	DTE Electric Company	DTE Energy Company	258,635	7,943	47,062,371
2014Y	DTE Electric Company	DTE Energy Company	289,196	2,900	46,076,577
2015Y	DTE Electric Company	DTE Energy Company	322,329	209	46,281,765
2016Y	DTE Electric Company	DTE Energy Company	354,944	1,135	45,998,164
2017Y	DTE Electric Company	DTE Energy Company	349,012	7,334	44,946,216
2013Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	55,116	243,441	85,789,697
2014Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	56,473	137,960	87,645,520
2015Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	57,407	201,452	87,375,571
2016Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	57,317	189,141	88,544,715

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2017Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	53,374	340,599	87,306,564
2013Y	Duke Energy Florida, LLC	Duke Energy Corporation	41,237	239,043	38,164,155
2014Y	Duke Energy Florida, LLC	Duke Energy Corporation	35,842	189,167	38,728,049
2015Y	Duke Energy Florida, LLC	Duke Energy Corporation	36,495	188,167	39,989,379
2016Y	Duke Energy Florida, LLC	Duke Energy Corporation	35,381	181,877	40,660,935
2017Y	Duke Energy Florida, LLC	Duke Energy Corporation	46,549	266,601	40,290,293
2013Y	Duke Energy Indiana, LLC	Duke Energy Corporation	46,188	115,011	33,714,982
2014Y	Duke Energy Indiana, LLC	Duke Energy Corporation	49,651	118,825	33,433,620
2015Y	Duke Energy Indiana, LLC	Duke Energy Corporation	62,855	74,032	33,517,569
2016Y	Duke Energy Indiana, LLC	Duke Energy Corporation	76,550	100,889	34,368,826
2017Y	Duke Energy Indiana, LLC	Duke Energy Corporation	82,485	142,417	33,145,670
2013Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	10,230	1,007	4,546,692
2014Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	13,842	7,571	4,447,988
2015Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	16,184	4,935	5,277,786
2016Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	19,418	700	4,672,987
2017Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	17,246	2,730	4,908,072
2013Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	25,124	45,539	39,309,749
2014Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	33,312	25,832	27,741,596
2015Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	31,977	55,837	20,805,363
2016Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	50,348	56,486	21,320,518
2017Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	48,077	49,640	20,805,946
2013Y	Duke Energy Progress, LLC	Duke Energy Corporation	61,419	189,440	60,204,063
2014Y	Duke Energy Progress, LLC	Duke Energy Corporation	54,336	114,663	62,871,047
2015Y	Duke Energy Progress, LLC	Duke Energy Corporation	38,719	95,587	64,880,560
2016Y	Duke Energy Progress, LLC	Duke Energy Corporation	46,483	137,888	69,052,154
2017Y	Duke Energy Progress, LLC	Duke Energy Corporation	38,809	167,725	66,822,736
2013Y	Southern California Edison Company	Edison International	316,012	2,118,269	90,552,978
2014Y	Southern California Edison Company	Edison International	243,690	1,314,334	116,437,195
2015Y	Southern California Edison Company	Edison International	312,494	1,242,955	90,495,397
2016Y	Southern California Edison Company	Edison International	227,741	1,033,844	88,194,998
2017Y	Southern California Edison Company	Edison International	221,093	646,614	91,291,726
2013Y	El Paso Electric Company	El Paso Electric Company	16,765	32,990	10,884,241

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2014Y	El Paso Electric Company	El Paso Electric Company	17,855	9,079	11,009,422
2015Y	El Paso Electric Company	El Paso Electric Company	19,120	27,893	10,915,601
2016Y	El Paso Electric Company	El Paso Electric Company	20,344	45,814	10,598,511
2017Y	El Paso Electric Company	El Paso Electric Company	21,078	23,975	10,904,754
2013Y	Emera Maine	Emera Incorporated	-24,811	37,033	1,869,923
2014Y	Emera Maine	Emera Incorporated	-18,855	51,638	2,344,241
2015Y	Emera Maine	Emera Incorporated	-17,907	32,240	2,325,046
2016Y	Emera Maine	Emera Incorporated	-18,404	28,722	2,217,874
2017Y	Emera Maine	Emera Incorporated	-15,537	23,979	2,270,073
2013Y	Tampa Electric Company	Emera Incorporated	12,705	27,782	18,639,927
2014Y	Tampa Electric Company	Emera Incorporated	13,840	24,585	18,784,911
2015Y	Tampa Electric Company	Emera Incorporated	14,223	48,401	19,121,762
2016Y	Tampa Electric Company	Emera Incorporated	16,125	143,882	19,440,142
2017Y	Tampa Electric Company	Emera Incorporated	14,411	42,354	19,425,418
2013Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2014Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2015Y	EL Investment Company, LLC	Entergy Corporation	37,473	107,498	31,482,380
2016Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2017Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2013Y	Entergy Arkansas, Inc.	Entergy Corporation	30,215	85,555	29,788,956
2014Y	Entergy Arkansas, Inc.	Entergy Corporation	43,309	106,685	31,350,781
2015Y	Entergy Arkansas, Inc.	Entergy Corporation	43,735	95,506	31,379,457
2016Y	Entergy Arkansas, Inc.	Entergy Corporation	40,348	302,310	29,363,790
2017Y	Entergy Arkansas, Inc.	Entergy Corporation	42,018	198,063	29,219,532
2013Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	28,052	96,753	27,130,595
2014Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	35,402	82,375	28,713,874
2015Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	28,828	56,431	21,426,698
2016Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA
2017Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA
2013Y	Entergy Louisiana, LLC	Entergy Corporation	36,229	72,156	34,156,904
2014Y	Entergy Louisiana, LLC	Entergy Corporation	50,685	119,022	37,479,888
2015Y	Entergy Louisiana, LLC	Entergy Corporation	23,696	24,209	14,743,976

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2016Y	Entergy Louisiana, LLC	Entergy Corporation	83,851	289,071	63,634,403
2017Y	Entergy Louisiana, LLC	Entergy Corporation	93,619	292,805	61,747,129
2013Y	Entergy Mississippi, Inc.	Entergy Corporation	20,588	72,446	14,965,739
2014Y	Entergy Mississippi, Inc.	Entergy Corporation	21,980	23,681	16,054,977
2015Y	Entergy Mississippi, Inc.	Entergy Corporation	21,768	34,188	14,969,217
2016Y	Entergy Mississippi, Inc.	Entergy Corporation	21,512	103,376	14,462,253
2017Y	Entergy Mississippi, Inc.	Entergy Corporation	19,842	190,528	13,904,918
2013Y	Entergy New Orleans, LLC	Entergy Corporation	13,359	5,716	5,615,573
2014Y	Entergy New Orleans, LLC	Entergy Corporation	14,389	15,544	6,570,789
2015Y	Entergy New Orleans, LLC	Entergy Corporation	14,327	12,547	7,138,626
2016Y	Entergy New Orleans, LLC	Entergy Corporation	9,255	18,924	6,947,771
2017Y	Entergy New Orleans, LLC	Entergy Corporation	8,438	5,956	7,327,377
2013Y	Entergy Texas, Inc.	Entergy Corporation	27,746	55,343	23,811,698
2014Y	Entergy Texas, Inc.	Entergy Corporation	30,688	38,850	22,661,605
2015Y	Entergy Texas, Inc.	Entergy Corporation	37,097	46,643	23,855,503
2016Y	Entergy Texas, Inc.	Entergy Corporation	28,775	242,073	23,892,632
2017Y	Entergy Texas, Inc.	Entergy Corporation	27,592	102,086	20,321,420
2013Y	System Energy Resources, Inc.	Entergy Corporation	0	22,439	9,793,557
2014Y	System Energy Resources, Inc.	Entergy Corporation	0	-33	9,218,542
2015Y	System Energy Resources, Inc.	Entergy Corporation	0	65	10,546,906
2016Y	System Energy Resources, Inc.	Entergy Corporation	0	-156	5,683,560
2017Y	System Energy Resources, Inc.	Entergy Corporation	0	0	6,675,148
2013Y	EWO Marketing, LLC	Entergy Corporation	-16,774	NA	2,589,069
2014Y	EWO Marketing, LLC	Entergy Corporation	3,385	NA	2,505,358
2015Y	EWO Marketing, LLC	Entergy Corporation	3,488	NA	2,504,139
2016Y	EWO Marketing, LLC	Entergy Corporation	3,820	NA	2,638,560
2017Y	EWO Marketing, LLC	Entergy Corporation	3,023	NA	2,648,461
2013Y	Connecticut Light and Power Company	Eversource Energy	115,480	272,433	23,299,945
2014Y	Connecticut Light and Power Company	Eversource Energy	77,432	212,363	22,647,162
2015Y	Connecticut Light and Power Company	Eversource Energy	85,295	343,309	22,643,456
2016Y	Connecticut Light and Power Company	Eversource Energy	104,645	278,252	22,342,433
2017Y	Connecticut Light and Power Company	Eversource Energy	135,222	330,352	21,611,697

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2013Y	NSTAR Electric Company	Eversource Energy	381,313	253,097	23,996,935
2014Y	NSTAR Electric Company	Eversource Energy	362,541	144,159	23,629,876
2015Y	NSTAR Electric Company	Eversource Energy	386,228	203,845	23,856,657
2016Y	NSTAR Electric Company	Eversource Energy	410,492	302,542	23,127,763
2017Y	NSTAR Electric Company	Eversource Energy	440,231	138,222	21,529,739
2013Y	Public Service Company of New Hampshire	Eversource Energy	36,701	84,364	9,118,546
2014Y	Public Service Company of New Hampshire	Eversource Energy	51,083	101,670	8,595,895
2015Y	Public Service Company of New Hampshire	Eversource Energy	33,959	125,876	8,441,532
2016Y	Public Service Company of New Hampshire	Eversource Energy	37,457	133,499	8,388,691
2017Y	Public Service Company of New Hampshire	Eversource Energy	50,674	101,147	8,116,389
2013Y	Western Massachusetts Electric Company	Eversource Energy	8,384	246,937	3,724,299
2014Y	Western Massachusetts Electric Company	Eversource Energy	20,725	65,163	3,610,361
2015Y	Western Massachusetts Electric Company	Eversource Energy	6,962	78,924	3,601,321
2016Y	Western Massachusetts Electric Company	Eversource Energy	13,808	92,110	3,706,255
2017Y	Western Massachusetts Electric Company	Eversource Energy	21,956	135,437	3,689,391
2013Y	Atlantic City Electric Company	Exelon Corporation	12,053	55,050	11,562,281
2014Y	Atlantic City Electric Company	Exelon Corporation	12,998	61,561	11,658,993
2015Y	Atlantic City Electric Company	Exelon Corporation	15,448	134,031	11,225,247
2016Y	Atlantic City Electric Company	Exelon Corporation	19,188	170,292	10,723,259
2017Y	Atlantic City Electric Company	Exelon Corporation	21,789	165,916	9,822,917
2013Y	Baltimore Gas and Electric Company	Exelon Corporation	35,100	45,746	30,767,778
2014Y	Baltimore Gas and Electric Company	Exelon Corporation	37,758	64,984	30,562,078
2015Y	Baltimore Gas and Electric Company	Exelon Corporation	42,726	106,230	30,304,293
2016Y	Baltimore Gas and Electric Company	Exelon Corporation	45,399	201,431	30,019,586
2017Y	Baltimore Gas and Electric Company	Exelon Corporation	46,870	229,910	28,970,770
2013Y	Commonwealth Edison Company	Exelon Corporation	229,733	218,055	93,089,440
2014Y	Commonwealth Edison Company	Exelon Corporation	243,867	592,902	90,578,581
2015Y	Commonwealth Edison Company	Exelon Corporation	293,633	353,477	87,297,520
2016Y	Commonwealth Edison Company	Exelon Corporation	369,632	532,117	89,608,490
2017Y	Commonwealth Edison Company	Exelon Corporation	427,803	411,459	87,568,519
2013Y	Delmarva Power & Light Company	Exelon Corporation	12,325	112,445	12,817,180
2014Y	Delmarva Power & Light Company	Exelon Corporation	13,512	134,192	12,782,957

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2015Y	Delmarva Power & Light Company	Exelon Corporation	18,075	113,216	12,805,844
2016Y	Delmarva Power & Light Company	Exelon Corporation	20,219	67,647	12,486,406
2017Y	Delmarva Power & Light Company	Exelon Corporation	24,434	175,951	12,222,536
2013Y	PECO Energy Company	Exelon Corporation	137,892	46,587	38,044,130
2014Y	PECO Energy Company	Exelon Corporation	127,928	21,427	37,681,485
2015Y	PECO Energy Company	Exelon Corporation	165,320	72,513	38,124,845
2016Y	PECO Energy Company	Exelon Corporation	195,562	90,138	37,940,620
2017Y	PECO Energy Company	Exelon Corporation	184,929	97,154	37,233,657
2013Y	Potomac Electric Power Company	Exelon Corporation	28,513	62,987	25,807,813
2014Y	Potomac Electric Power Company	Exelon Corporation	28,500	88,450	25,750,549
2015Y	Potomac Electric Power Company	Exelon Corporation	31,958	84,084	25,987,432
2016Y	Potomac Electric Power Company	Exelon Corporation	35,263	53,597	26,114,290
2017Y	Potomac Electric Power Company	Exelon Corporation	31,875	212,365	24,855,893
2013Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	88,011	6,980	18,712,244
2014Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	90,593	6,780	18,733,302
2015Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	165,848	10,026	18,501,986
2016Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	186,461	21,331	18,817,928
2017Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	198,785	3,646	18,290,574
2013Y	Jersey Central Power & Light Company	FirstEnergy Corp.	21,873	51,416	21,836,806
2014Y	Jersey Central Power & Light Company	FirstEnergy Corp.	28,943	71,056	21,846,258
2015Y	Jersey Central Power & Light Company	FirstEnergy Corp.	30,457	57,133	21,332,986
2016Y	Jersey Central Power & Light Company	FirstEnergy Corp.	19,203	133,376	21,250,880
2017Y	Jersey Central Power & Light Company	FirstEnergy Corp.	28,922	170,923	20,535,764
2013Y	Metropolitan Edison Company	FirstEnergy Corp.	18,774	28,722	14,226,643
2014Y	Metropolitan Edison Company	FirstEnergy Corp.	24,267	5,744	14,276,774
2015Y	Metropolitan Edison Company	FirstEnergy Corp.	23,436	31,057	14,291,940
2016Y	Metropolitan Edison Company	FirstEnergy Corp.	23,385	18,746	14,143,059
2017Y	Metropolitan Edison Company	FirstEnergy Corp.	15,053	887	13,777,426
2013Y	Monongahela Power Company	FirstEnergy Corp.	104,745	11,909	10,816,852
2014Y	Monongahela Power Company	FirstEnergy Corp.	244,607	22,536	17,361,198
2015Y	Monongahela Power Company	FirstEnergy Corp.	140,798	17,211	16,163,874
2016Y	Monongahela Power Company	FirstEnergy Corp.	107,056	19,440	17,434,322

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Monongahela Power Company	FirstEnergy Corp.	87,565	32,187	17,497,075
2013Y	Ohio Edison Company	FirstEnergy Corp.	158,352	5,736	27,059,942
2014Y	Ohio Edison Company	FirstEnergy Corp.	157,590	729	27,819,394
2015Y	Ohio Edison Company	FirstEnergy Corp.	217,345	4,510	27,056,153
2016Y	Ohio Edison Company	FirstEnergy Corp.	247,830	3,131	26,451,421
2017Y	Ohio Edison Company	FirstEnergy Corp.	265,836	2,709	23,977,058
2013Y	Pennsylvania Electric Company	FirstEnergy Corp.	20,718	30,943	15,484,578
2014Y	Pennsylvania Electric Company	FirstEnergy Corp.	29,706	31,076	14,771,582
2015Y	Pennsylvania Electric Company	FirstEnergy Corp.	34,927	50,797	14,473,442
2016Y	Pennsylvania Electric Company	FirstEnergy Corp.	40,448	20,200	14,386,263
2017Y	Pennsylvania Electric Company	FirstEnergy Corp.	33,896	220	14,363,454
2013Y	Pennsylvania Power Company	FirstEnergy Corp.	7,406	839	4,567,609
2014Y	Pennsylvania Power Company	FirstEnergy Corp.	7,200	262	4,714,488
2015Y	Pennsylvania Power Company	FirstEnergy Corp.	5,024	661	4,526,159
2016Y	Pennsylvania Power Company	FirstEnergy Corp.	4,888	741	4,615,081
2017Y	Pennsylvania Power Company	FirstEnergy Corp.	5,125	874	4,633,922
2013Y	Potomac Edison Company	FirstEnergy Corp.	12,521	9,214	11,862,840
2014Y	Potomac Edison Company	FirstEnergy Corp.	18,919	41,864	11,898,341
2015Y	Potomac Edison Company	FirstEnergy Corp.	23,012	12,716	11,823,082
2016Y	Potomac Edison Company	FirstEnergy Corp.	31,594	22,336	11,554,451
2017Y	Potomac Edison Company	FirstEnergy Corp.	25,987	13,181	11,322,812
2013Y	Toledo Edison Company	FirstEnergy Corp.	59,050	1,052	11,956,365
2014Y	Toledo Edison Company	FirstEnergy Corp.	57,526	845	11,873,197
2015Y	Toledo Edison Company	FirstEnergy Corp.	86,936	1,392	11,779,382
2016Y	Toledo Edison Company	FirstEnergy Corp.	99,301	340	12,079,562
2017Y	Toledo Edison Company	FirstEnergy Corp.	104,469	439	10,856,745
2013Y	West Penn Power Company	FirstEnergy Corp.	36,703	11,945	20,052,177
2014Y	West Penn Power Company	FirstEnergy Corp.	44,467	11,840	20,291,236
2015Y	West Penn Power Company	FirstEnergy Corp.	52,421	16,623	20,083,013
2016Y	West Penn Power Company	FirstEnergy Corp.	58,089	9,763	19,998,876
2017Y	West Penn Power Company	FirstEnergy Corp.	76,934	19,456	19,616,843
2013Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	10,006	14,919	2,761,676

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	11,048	16,180	2,623,309
2015Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	11,512	27,937	2,608,207
2016Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	11,238	20,040	2,684,357
2017Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	10,636	31,353	2,602,989
2013Y	Tucson Electric Power Company	Fortis Inc.	15,350	35,201	13,025,375
2014Y	Tucson Electric Power Company	Fortis Inc.	16,560	78,651	13,311,011
2015Y	Tucson Electric Power Company	Fortis Inc.	24,317	120,689	14,279,396
2016Y	Tucson Electric Power Company	Fortis Inc.	24,381	28,483	13,718,397
2017Y	Tucson Electric Power Company	Fortis Inc.	30,952	42,329	13,442,595
2013Y	UNS Electric, Inc.	Fortis Inc.	13,494	46,506	2,230,041
2014Y	UNS Electric, Inc.	Fortis Inc.	12,453	14,037	1,982,714
2015Y	UNS Electric, Inc.	Fortis Inc.	20,886	3,190	1,746,289
2016Y	UNS Electric, Inc.	Fortis Inc.	21,802	7,039	1,762,853
2017Y	UNS Electric, Inc.	Fortis Inc.	17,425	4,493	1,916,799
2013Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	53,986	19,788	21,683,329
2014Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	64,368	13,934	22,472,307
2015Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	75,630	17,091	20,796,733
2016Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	72,526	21,445	21,433,876
2017Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	85,899	17,125	21,322,723
2013Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	21,259	22,617	8,413,828
2014Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	37,937	13,853	8,511,766
2015Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	39,570	10,837	8,385,574
2016Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	37,371	19,357	8,465,650
2017Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	47,345	10,838	8,386,821
2013Y	Central Maine Power Company	Iberdrola, S.A.	145,865	363,457	603,824
2014Y	Central Maine Power Company	Iberdrola, S.A.	152,667	376,458	590,204
2015Y	Central Maine Power Company	Iberdrola, S.A.	161,621	419,189	600,705
2016Y	Central Maine Power Company	Iberdrola, S.A.	173,794	60,357	599,743
2017Y	Central Maine Power Company	Iberdrola, S.A.	185,931	46,257	172,595
2013Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	43,677	30,423	19,115,201
2014Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	44,347	35,015	18,690,994
2015Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	46,526	26,861	17,887,199

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2016Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	47,010	5,514	17,455,920
2017Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	42,068	141,184	16,633,428
2013Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	11,098	88,218	9,024,632
2014Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	11,112	28,126	7,970,527
2015Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	16,811	3,652	7,319,681
2016Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	12,512	9,096	7,365,999
2017Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	10,116	163,557	7,216,272
2013Y	United Illuminating Company	Iberdrola, S.A.	122,290	66,552	5,422,427
2014Y	United Illuminating Company	Iberdrola, S.A.	133,723	37,085	5,327,395
2015Y	United Illuminating Company	Iberdrola, S.A.	139,123	48,697	5,450,238
2016Y	United Illuminating Company	Iberdrola, S.A.	144,985	87,813	5,334,351
2017Y	United Illuminating Company	Iberdrola, S.A.	157,507	33,937	5,093,904
2013Y	Idaho Power Co.	IDACORP, Inc.	26,450	45,517	16,302,681
2014Y	Idaho Power Co.	IDACORP, Inc.	27,336	46,722	16,312,786
2015Y	Idaho Power Co.	IDACORP, Inc.	27,353	66,247	15,518,629
2016Y	Idaho Power Co.	IDACORP, Inc.	25,408	49,498	15,381,629
2017Y	Idaho Power Co.	IDACORP, Inc.	25,279	48,021	16,706,603
2013Y	Kentucky Utilities Company	LKE	27,779	42,404	21,629,993
2014Y	Kentucky Utilities Company	LKE	30,428	44,056	21,986,858
2015Y	Kentucky Utilities Company	LKE	31,973	49,166	21,810,131
2016Y	Kentucky Utilities Company	LKE	31,677	74,824	21,437,963
2017Y	Kentucky Utilities Company	LKE	34,598	61,742	20,497,797
2013Y	Louisville Gas and Electric Company	LKE	14,397	16,161	14,478,316
2014Y	Louisville Gas and Electric Company	LKE	14,746	29,548	15,373,731
2015Y	Louisville Gas and Electric Company	LKE	14,636	38,265	13,502,213
2016Y	Louisville Gas and Electric Company	LKE	15,057	45,370	13,156,493
2017Y	Louisville Gas and Electric Company	LKE	15,343	8,951	13,133,134
2013Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	10,729	16,428	3,195,882
2014Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	13,968	34,505	3,331,202
2015Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	13,469	24,925	3,316,058
2016Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	34,017	28,765	3,303,555
2017Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	36,860	13,724	3,346,441

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Madison Gas and Electric Company	MGE Energy, Inc.	33,059	0	3,557,446
2014Y	Madison Gas and Electric Company	MGE Energy, Inc.	33,146	0	3,514,574
2015Y	Madison Gas and Electric Company	MGE Energy, Inc.	36,332	0	3,545,081
2016Y	Madison Gas and Electric Company	MGE Energy, Inc.	36,422	0	3,741,999
2017Y	Madison Gas and Electric Company	MGE Energy, Inc.	41,610	0	3,584,998
2013Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	721	117	99,446
2014Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	739	37	99,841
2015Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	765	89	99,902
2016Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	866	130	95,751
2017Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	836	127	95,101
2013Y	Massachusetts Electric Company	National Grid plc	392,635	5,925	11,080,137
2014Y	Massachusetts Electric Company	National Grid plc	424,849	5,430	10,608,963
2015Y	Massachusetts Electric Company	National Grid plc	440,490	8,135	8,699,117
2016Y	Massachusetts Electric Company	National Grid plc	447,201	1,094	6,486,573
2017Y	Massachusetts Electric Company	National Grid plc	478,822	9,890	6,427,679
2013Y	Narragansett Electric Company	National Grid plc	47,117	153,567	5,133,864
2014Y	Narragansett Electric Company	National Grid plc	52,197	27,387	5,006,934
2015Y	Narragansett Electric Company	National Grid plc	40,070	166,837	4,492,267
2016Y	Narragansett Electric Company	National Grid plc	41,906	116,010	3,954,763
2017Y	Narragansett Electric Company	National Grid plc	68,123	39,163	3,868,162
2013Y	New England Power Company	National Grid plc	61,559	165,061	570,917
2014Y	New England Power Company	National Grid plc	60,821	263,633	565,418
2015Y	New England Power Company	National Grid plc	69,771	187,218	566,430
2016Y	New England Power Company	National Grid plc	58,485	255,629	314,990
2017Y	New England Power Company	National Grid plc	62,364	177,147	239,434
2013Y	Niagara Mohawk Power Corporation	National Grid plc	117,334	154,594	16,348,792
2014Y	Niagara Mohawk Power Corporation	National Grid plc	119,553	164,121	13,620,478
2015Y	Niagara Mohawk Power Corporation	National Grid plc	103,643	244,218	13,464,032
2016Y	Niagara Mohawk Power Corporation	National Grid plc	72,612	224,713	13,600,814
2017Y	Niagara Mohawk Power Corporation	National Grid plc	81,743	137,110	13,190,657
2013Y	Florida Power & Light Company	NextEra Energy, Inc.	90,853	158,259	107,373,794
2014Y	Florida Power & Light Company	NextEra Energy, Inc.	98,718	290,960	112,929,729

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Florida Power & Light Company	NextEra Energy, Inc.	103,510	347,636	119,405,262
2016Y	Florida Power & Light Company	NextEra Energy, Inc.	78,459	450,157	119,279,691
2017Y	Florida Power & Light Company	NextEra Energy, Inc.	98,668	359,278	117,873,183
2013Y	Northern Indiana Public Service Company	NiSource Inc.	29,449	25,817	17,468,011
2014Y	Northern Indiana Public Service Company	NiSource Inc.	31,374	50,200	18,186,288
2015Y	Northern Indiana Public Service Company	NiSource Inc.	35,857	50,666	16,758,427
2016Y	Northern Indiana Public Service Company	NiSource Inc.	44,263	34,012	16,831,194
2017Y	Northern Indiana Public Service Company	NiSource Inc.	46,177	106,710	16,725,564
2013Y	NorthWestern Corporation	NorthWestern Corporation	29,595	29,483	9,519,519
2014Y	NorthWestern Corporation	NorthWestern Corporation	28,579	40,734	10,006,908
2015Y	NorthWestern Corporation	NorthWestern Corporation	27,739	96,006	11,027,880
2016Y	NorthWestern Corporation	NorthWestern Corporation	30,330	40,319	9,037,846
2017Y	NorthWestern Corporation	NorthWestern Corporation	43,449	98,010	8,924,244
2013Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	109,160	280,944	28,578,159
2014Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	122,725	542,641	30,234,927
2015Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	133,786	62,264	28,867,056
2016Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	168,202	123,134	29,762,475
2017Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	168,890	122,311	28,111,471
2013Y	Otter Tail Power Company	Otter Tail Corporation	19,286	9,559	6,219,751
2014Y	Otter Tail Power Company	Otter Tail Corporation	23,817	54,661	5,470,896
2015Y	Otter Tail Power Company	Otter Tail Corporation	27,080	70,054	4,709,464
2016Y	Otter Tail Power Company	Otter Tail Corporation	32,582	19,206	4,955,630
2017Y	Otter Tail Power Company	Otter Tail Corporation	31,130	91,651	5,040,591
2013Y	Pacific Gas and Electric Company	PG&E Corporation	227,245	818,308	88,322,913
2014Y	Pacific Gas and Electric Company	PG&E Corporation	243,048	727,387	88,189,685
2015Y	Pacific Gas and Electric Company	PG&E Corporation	286,712	898,809	87,981,023
2016Y	Pacific Gas and Electric Company	PG&E Corporation	296,115	1,056,052	85,067,412
2017Y	Pacific Gas and Electric Company	PG&E Corporation	300,976	696,359	88,175,650
2013Y	Arizona Public Service Company	Pinnacle West Capital Corporation	72,068	77,880	32,087,545
2014Y	Arizona Public Service Company	Pinnacle West Capital Corporation	79,638	32,970	32,951,388
2015Y	Arizona Public Service Company	Pinnacle West Capital Corporation	83,335	257,482	33,628,854
2016Y	Arizona Public Service Company	Pinnacle West Capital Corporation	81,642	258,354	31,928,046

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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Arizona Public Service Company	Pinnacle West Capital Corporation	82,704	98,023	30,910,170
2013Y	Public Service Company of New Mexico	PNM Resources, Inc.	38,078	33,818	12,001,980
2014Y	Public Service Company of New Mexico	PNM Resources, Inc.	38,628	52,003	11,836,387
2015Y	Public Service Company of New Mexico	PNM Resources, Inc.	37,692	78,444	11,541,512
2016Y	Public Service Company of New Mexico	PNM Resources, Inc.	34,985	75,688	12,280,191
2017Y	Public Service Company of New Mexico	PNM Resources, Inc.	36,621	74,904	12,454,143
2013Y	Portland General Electric Company	Portland General Electric Company	88,564	6,145	21,226,863
2014Y	Portland General Electric Company	Portland General Electric Company	96,567	24,571	21,080,082
2015Y	Portland General Electric Company	Portland General Electric Company	98,092	10,788	20,859,230
2016Y	Portland General Electric Company	Portland General Electric Company	95,365	61,689	21,247,271
2017Y	Portland General Electric Company	Portland General Electric Company	104,282	27,179	21,328,945
2013Y	PPL Electric Utilities Corporation	PPL Corporation	115,259	360,786	37,712,878
2014Y	PPL Electric Utilities Corporation	PPL Corporation	121,864	487,611	38,005,667
2015Y	PPL Electric Utilities Corporation	PPL Corporation	141,493	961,657	37,967,738
2016Y	PPL Electric Utilities Corporation	PPL Corporation	146,935	518,077	37,618,811
2017Y	PPL Electric Utilities Corporation	PPL Corporation	148,234	813,697	36,939,991
2013Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	85,305	1,061,404	44,103,026
2014Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	88,785	1,949,423	42,728,622
2015Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	92,088	1,764,577	43,533,905
2016Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	109,882	1,673,182	42,288,312
2017Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	108,849	1,322,621	40,894,038
2013Y	Puget Sound Energy, Inc.	Puget Holdings LLC	114,098	49,245	26,265,216
2014Y	Puget Sound Energy, Inc.	Puget Holdings LLC	130,002	98,082	21,968,767
2015Y	Puget Sound Energy, Inc.	Puget Holdings LLC	130,460	33,206	28,183,148
2016Y	Puget Sound Energy, Inc.	Puget Holdings LLC	134,458	64,193	29,143,765
2017Y	Puget Sound Energy, Inc.	Puget Holdings LLC	138,493	93,885	27,227,367
2013Y	South Carolina Electric & Gas Co.	SCANA Corporation	18,376	60,863	22,326,578
2014Y	South Carolina Electric & Gas Co.	SCANA Corporation	21,707	109,883	23,332,942
2015Y	South Carolina Electric & Gas Co.	SCANA Corporation	17,983	91,373	23,114,845
2016Y	South Carolina Electric & Gas Co.	SCANA Corporation	17,972	65,843	23,471,194
2017Y	South Carolina Electric & Gas Co.	SCANA Corporation	23,053	363,115	22,879,069
2013Y	Oncor Electric Delivery Company LLC	Sempra Energy	648,730	663,088	112,312,279

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2014Y	Oncor Electric Delivery Company LLC	Sempra Energy	815,763	749,086	114,905,829
2015Y	Oncor Electric Delivery Company LLC	Sempra Energy	864,378	379,200	116,594,625
2016Y	Oncor Electric Delivery Company LLC	Sempra Energy	963,301	580,164	115,791,379
2017Y	Oncor Electric Delivery Company LLC	Sempra Energy	997,203	610,460	117,017,075
2013Y	San Diego Gas & Electric Co.	Sempra Energy	95,859	236,436	32,916,382
2014Y	San Diego Gas & Electric Co.	Sempra Energy	81,094	599,992	30,952,957
2015Y	San Diego Gas & Electric Co.	Sempra Energy	85,341	360,021	33,132,033
2016Y	San Diego Gas & Electric Co.	Sempra Energy	87,877	294,786	29,443,890
2017Y	San Diego Gas & Electric Co.	Sempra Energy	87,096	477,153	29,300,970
2013Y	Alabama Power Company	Southern Company	60,633	176,759	66,309,626
2014Y	Alabama Power Company	Southern Company	73,289	316,899	67,155,314
2015Y	Alabama Power Company	Southern Company	71,603	225,560	63,847,336
2016Y	Alabama Power Company	Southern Company	81,966	168,478	63,873,423
2017Y	Alabama Power Company	Southern Company	88,563	228,714	63,290,561
2013Y	Georgia Power Company	Southern Company	107,047	314,998	84,726,779
2014Y	Georgia Power Company	Southern Company	132,535	281,411	89,190,865
2015Y	Georgia Power Company	Southern Company	108,279	326,941	87,859,128
2016Y	Georgia Power Company	Southern Company	139,315	360,958	89,686,468
2017Y	Georgia Power Company	Southern Company	105,047	297,025	86,478,222
2013Y	Gulf Power Company	Southern Company	20,792	50,423	14,909,545
2014Y	Gulf Power Company	Southern Company	25,233	48,531	16,028,868
2015Y	Gulf Power Company	Southern Company	25,807	184,474	14,031,937
2016Y	Gulf Power Company	Southern Company	26,960	16,402	14,616,769
2017Y	Gulf Power Company	Southern Company	26,683	18,640	15,445,454
2013Y	Mississippi Power Company	Southern Company	14,835	73,265	14,591,834
2014Y	Mississippi Power Company	Southern Company	13,197	32,964	17,059,643
2015Y	Mississippi Power Company	Southern Company	11,705	22,173	16,487,788
2016Y	Mississippi Power Company	Southern Company	15,573	27,317	14,866,485
2017Y	Mississippi Power Company	Southern Company	11,013	28,622	15,283,882
2013Y	Southern Electric Generating Company	Southern Company	793	569	2,107,334
2014Y	Southern Electric Generating Company	Southern Company	695	93	2,084,739
2015Y	Southern Electric Generating Company	Southern Company	761	1,935	1,277,061

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2016Y	Southern Electric Generating Company	Southern Company	758	916	394,540
2017Y	Southern Electric Generating Company	Southern Company	762	845	1,406,811
2013Y	UGI Utilities, Inc.	UGI Corporation	7,620	1,254	1,000,701
2014Y	UGI Utilities, Inc.	UGI Corporation	7,219	1,886	975,771
2015Y	UGI Utilities, Inc.	UGI Corporation	6,997	1,684	990,384
2016Y	UGI Utilities, Inc.	UGI Corporation	7,020	3,298	977,118
2017Y	UGI Utilities, Inc.	UGI Corporation	6,935	3,241	956,654
2013Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	7,170	3,376	505,418
2014Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	7,388	1,272	533,929
2015Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	8,026	275	460,811
2016Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	8,244	782	444,498
2017Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	8,980	130	455,496
2013Y	Unitil Energy Systems, Inc.	Unitil Corporation	23,753	0	1,234,354
2014Y	Unitil Energy Systems, Inc.	Unitil Corporation	22,418	0	1,230,055
2015Y	Unitil Energy Systems, Inc.	Unitil Corporation	25,401	0	1,229,879
2016Y	Unitil Energy Systems, Inc.	Unitil Corporation	27,707	0	1,203,404
2017Y	Unitil Energy Systems, Inc.	Unitil Corporation	30,265	0	1,215,797
2013Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	13,676	12,117	5,993,477
2014Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	15,566	23,338	6,240,584
2015Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	17,885	8,640	5,795,918
2016Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	21,206	17,190	5,610,259
2017Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	17,802	12,054	5,220,819
2013Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	263,488	0	32,555,334
2014Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	275,927	0	32,942,828
2015Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	270,365	0	35,818,700
2016Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	293,123	0	35,894,209
2017Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	249,842	0	34,951,750
2013Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	120,106	0	16,129,893
2014Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	125,369	0	14,557,949
2015Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	135,533	0	14,839,077
2016Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	148,914	0	14,636,889
2017Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	139,007	0	14,814,995

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Kansas Gas and Electric Company	Westar Energy, Inc.	100,515	51,781	10,605,055
2014Y	Kansas Gas and Electric Company	Westar Energy, Inc.	124,606	94,400	10,800,465
2015Y	Kansas Gas and Electric Company	Westar Energy, Inc.	125,341	100,247	10,761,626
2016Y	Kansas Gas and Electric Company	Westar Energy, Inc.	127,328	60,430	11,297,034
2017Y	Kansas Gas and Electric Company	Westar Energy, Inc.	132,014	48,982	10,847,878
2013Y	Westar Energy (KPL)	Westar Energy, Inc.	102,195	64,304	17,484,374
2014Y	Westar Energy (KPL)	Westar Energy, Inc.	126,821	123,786	18,531,716
2015Y	Westar Energy (KPL)	Westar Energy, Inc.	129,031	47,299	17,180,535
2016Y	Westar Energy (KPL)	Westar Energy, Inc.	130,856	126,264	16,555,817
2017Y	Westar Energy (KPL)	Westar Energy, Inc.	133,385	96,081	18,790,662
2013Y	Westar Generating, Inc.	Westar Energy, Inc.	7	0	735,166
2014Y	Westar Generating, Inc.	Westar Energy, Inc.	2	0	608,351
2015Y	Westar Generating, Inc.	Westar Energy, Inc.	14	0	690,492
2016Y	Westar Generating, Inc.	Westar Energy, Inc.	2	0	945,870
2017Y	Westar Generating, Inc.	Westar Energy, Inc.	4	0	983,635
2013Y	Northern States Power Company - MN	Xcel Energy Inc.	244,340	160,201	37,474,524
2014Y	Northern States Power Company - MN	Xcel Energy Inc.	272,848	556,234	39,129,144
2015Y	Northern States Power Company - MN	Xcel Energy Inc.	309,442	466,046	39,484,126
2016Y	Northern States Power Company - MN	Xcel Energy Inc.	355,752	182,398	41,519,021
2017Y	Northern States Power Company - MN	Xcel Energy Inc.	369,339	146,364	40,720,489
2013Y	Northern States Power Company - WI	Xcel Energy Inc.	47,064	69,655	6,562,368
2014Y	Northern States Power Company - WI	Xcel Energy Inc.	58,765	87,610	6,750,889
2015Y	Northern States Power Company - WI	Xcel Energy Inc.	46,131	234,332	6,647,300
2016Y	Northern States Power Company - WI	Xcel Energy Inc.	66,586	35,565	6,641,542
2017Y	Northern States Power Company - WI	Xcel Energy Inc.	80,072	34,794	6,727,740
2013Y	Public Service Company of Colorado	Xcel Energy Inc.	61,572	131,265	33,450,187
2014Y	Public Service Company of Colorado	Xcel Energy Inc.	58,061	116,518	32,498,488
2015Y	Public Service Company of Colorado	Xcel Energy Inc.	52,952	85,517	32,396,474
2016Y	Public Service Company of Colorado	Xcel Energy Inc.	53,338	107,704	34,472,722
2017Y	Public Service Company of Colorado	Xcel Energy Inc.	54,763	86,184	36,486,396
2013Y	Southwestern Public Service Company	Xcel Energy Inc.	115,728	170,080	28,292,788
2014Y	Southwestern Public Service Company	Xcel Energy Inc.	126,490	497,237	28,265,391

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Transmission O&M Expense ($000)	Total Transmission Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Southwestern Public Service Company	Xcel Energy Inc.	145,594	333,420	28,414,831
2016Y	Southwestern Public Service Company	Xcel Energy Inc.	173,307	258,530	28,383,129
2017Y	Southwestern Public Service Company	Xcel Energy Inc.	191,522	195,947	27,124,064
		Total	57,619,237	79,628,556	14,787,574,406

Distribution [2013-2017] Rankings   Source: SNL

Holding Company	Distribution O&M	Distribution Plant: Add	Total Cash Costs	Total Sales of Elect. Volume (MWh)	Dist O&M and Plant/MWh	Ranking
ALLETE, Inc.	131,444,000	139,462,000	270,906,000	74,330,795	3.64	1
Entergy Corporation	1,222,166,000	2,849,524,000	4,071,690,000	694,118,461	5.87	2
Berkshire Hathaway Inc.	1,725,328,000	2,541,735,000	4,267,063,000	647,595,062	6.59	3
Otter Tail Corporation	83,277,000	92,318,000	175,595,000	26,396,332	6.65	4
AES Corporation	393,179,000	665,238,000	1,058,417,000	157,380,054	6.73	5
PNM Resources, Inc.	109,355,000	298,719,000	408,074,000	60,114,213	6.79	6
LKE	526,284,290	789,470,000	1,315,754,290	177,006,629	7.43	7
Xcel Energy Inc.	1,356,048,000	2,718,575,000	4,074,623,000	541,441,613	7.53	8
CenterPoint Energy, Inc.	1,160,162,000	2,067,320,000	3,227,482,000	421,479,989	7.66	9
IDACORP, Inc.	242,318,000	373,729,000	616,047,000	80,222,328	7.68	10
El Paso Electric Company	111,835,000	311,389,000	423,224,000	54,312,529	7.79	11
Southern Company	2,747,952,000	4,459,294,000	7,207,246,000	915,739,927	7.87	12
SCANA Corporation	264,964,000	669,186,000	934,150,000	115,124,628	8.11	13
Vectren Corporation	77,943,000	160,072,000	238,015,000	28,861,057	8.25	14
Sempra Energy	1,799,652,000	4,343,929,000	6,143,581,000	732,367,419	8.39	15
NiSource Inc.	226,592,000	509,640,000	736,232,000	85,969,484	8.56	16
Westar Energy, Inc.	452,871,000	771,147,000	1,224,018,000	142,855,162	8.57	17
Duke Energy Corporation	3,606,542,000	7,365,314,000	10,971,856,000	1,280,342,802	8.57	18
FirstEnergy Corp.	2,325,781,000	4,618,961,000	6,944,742,000	795,797,359	8.73	19
Cleco Partners LP	149,310,000	375,156,000	524,466,000	58,299,323	9.00	20
Great Plains Energy Inc	433,341,000	935,725,000	1,369,066,000	149,872,607	9.13	21
WEC Energy Group, Inc.	644,496,000	1,640,123,000	2,284,619,000	247,141,624	9.24	22
Puget Holdings LLC	406,914,000	821,874,000	1,228,788,000	132,788,263	9.25	23
Dominion Energy, Inc.	971,051,000	2,979,749,000	3,950,800,000	424,814,207	9.30	24
OGE Energy Corp.	411,823,000	950,189,000	1,362,012,000	145,554,088	9.36	25
AEP	3,473,281,000	5,502,148,000	8,975,429,000	926,060,218	9.69	26

Distribution [2013-2017] Rankings   Source: SNL

Holding Company	Distribution O&M	Distribution Plant: Add	Total Cash Costs	Total Sales of Elect. Volume (MWh)	Dist O&M and Plant/MWh	Ranking
Avista Corporation	179,854,000	461,608,000	641,462,000	63,822,212	10.05	27
Pinnacle West Capital Corp	498,192,000	1,228,762,000	1,726,954,000	161,506,003	10.69	28
Emera Incorporated	332,232,000	846,943,000	1,179,175,000	106,439,317	11.08	29
Fortis Inc.	373,224,000	647,033,000	1,020,257,000	90,696,008	11.25	30
Black Hills Corporation	137,730,000	226,125,000	363,855,000	32,232,125	11.29	31
Alliant Energy Corporation	300,268,000	1,526,881,000	1,827,149,000	158,149,961	11.55	32
Ameren Corporation	1,915,446,000	2,839,002,000	4,754,448,000	396,912,264	11.98	33
PPL Corporation	823,592,000	1,550,544,000	2,374,136,000	188,245,085	12.61	34
Portland General Electric Co	531,921,000	821,320,000	1,353,241,000	105,742,391	12.80	35
DQE Holdings LLC	213,949,000	653,506,000	867,455,000	67,127,889	12.92	36
NextEra Energy, Inc.	2,527,266,000	5,065,762,000	7,593,028,000	576,861,659	13.16	37
UGI Corporation	34,400,000	30,738,000	65,138,000	4,900,628	13.29	38
Public Service Enterprise Group	845,817,000	2,002,632,000	2,848,449,000	213,547,903	13.34	39
MGE Energy, Inc.	71,935,000	176,946,000	248,881,000	17,944,098	13.87	40
MDU Resources Group, Inc.	77,742,000	152,848,000	230,590,000	16,493,138	13.98	41
NorthWestern Corporation	241,548,000	481,396,000	722,944,000	48,516,397	14.90	42
Algonquin Power & Utilities	173,268,000	278,461,000	451,729,000	29,685,318	15.22	43
DTE Energy Company	1,455,783,000	2,187,763,000	3,643,546,000	230,365,093	15.82	44
Caisse de dépôt et	171,615,000	231,135,000	402,750,000	23,640,213	17.04	45
CMS Energy Corporation	912,735,000	2,183,419,000	3,096,154,000	180,393,075	17.16	46
Exelon Corporation	6,045,349,000	11,839,199,000	17,884,548,000	1,034,415,389	17.29	47
Eversource Energy	1,771,282,000	3,280,772,000	5,052,054,000	289,678,343	17.44	48
Edison International	2,501,196,000	7,718,230,000	10,219,426,000	476,972,294	21.43	49
Iberdrola, S.A.	2,035,673,000	1,476,155,000	3,511,828,000	157,875,239	22.24	50
Unitil Corporation	64,283,000	125,644,000	189,927,000	8,513,641	22.31	51
Balfour Beatty Infrastructure	65,142,000	35,986,000	101,128,000	4,147,629	24.38	52

Distribution [2013-2017] Rankings   Source: SNL

Holding Company	Distribution O&M	Distribution Plant: Add	Total Cash Costs	Total Sales of Elect. Volume (MWh)	Dist O&M and Plant/MWh	Ranking
Mt. Carmel Public Utility Co	6,951,000	5,249,000	12,200,000	490,041	24.90	53
PG&E Corporation	3,793,462,000	7,439,437,000	11,232,899,000	437,736,683	25.66	54
Consolidated Edison, Inc.	2,887,687,000	6,118,124,000	9,005,811,000	264,071,298	34.10	55
National Grid plc	2,338,864,000	2,781,997,000	5,120,861,000	138,240,421	37.04	56
	58,382,315,290	113,363,603,000	171,745,918,290	14,641,347,928		

Q1	8.35
Q2	10.89
Q3	14.98
Industry Avg.	11.73

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Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Dayton Power and Light Company	AES Corporation	33,218	76,614	19,416,290
2014Y	Dayton Power and Light Company	AES Corporation	37,767	47,364	18,643,195
2015Y	Dayton Power and Light Company	AES Corporation	53,049	84,046	16,433,036
2016Y	Dayton Power and Light Company	AES Corporation	36,251	85,476	16,158,129
2017Y	Dayton Power and Light Company	AES Corporation	34,573	69,271	12,236,126
2013Y	Indianapolis Power & Light Company	AES Corporation	36,907	42,490	16,033,922
2014Y	Indianapolis Power & Light Company	AES Corporation	37,733	58,730	16,391,321
2015Y	Indianapolis Power & Light Company	AES Corporation	39,364	63,910	14,397,561
2016Y	Indianapolis Power & Light Company	AES Corporation	41,074	69,591	14,185,985
2017Y	Indianapolis Power & Light Company	AES Corporation	43,243	67,746	13,484,489
2013Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	26,783	28,798	5,620,276
2014Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	30,603	54,676	5,131,750
2015Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	29,023	32,341	4,940,028
2016Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	26,993	38,100	4,950,707
2017Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	24,891	51,716	4,841,355
2013Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	5,879	10,133	552,273
2014Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	7,729	20,866	910,825
2015Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	7,022	10,123	933,262
2016Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	7,443	18,127	910,242
2017Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	6,902	13,581	894,600
2013Y	ALLETE (Minnesota Power)	ALLETE, Inc.	22,181	21,045	13,264,062
2014Y	ALLETE (Minnesota Power)	ALLETE, Inc.	24,612	23,412	13,942,499
2015Y	ALLETE (Minnesota Power)	ALLETE, Inc.	24,187	20,733	14,369,559
2016Y	ALLETE (Minnesota Power)	ALLETE, Inc.	27,423	37,084	14,147,335
2017Y	ALLETE (Minnesota Power)	ALLETE, Inc.	25,593	27,828	14,692,658
2013Y	Superior Water, Light and Power Company	ALLETE, Inc.	1,651	2,612	687,209
2014Y	Superior Water, Light and Power Company	ALLETE, Inc.	1,336	1,229	770,427
2015Y	Superior Water, Light and Power Company	ALLETE, Inc.	1,614	465	788,342
2016Y	Superior Water, Light and Power Company	ALLETE, Inc.	1,664	2,053	820,880

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Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Superior Water, Light and Power Company	ALLETE, Inc.	1,183	3,001	847,824
2013Y	Interstate Power and Light Company	Alliant Energy Corporation	32,277	126,320	17,194,056
2014Y	Interstate Power and Light Company	Alliant Energy Corporation	33,407	182,041	16,871,181
2015Y	Interstate Power and Light Company	Alliant Energy Corporation	34,043	171,110	16,703,172
2016Y	Interstate Power and Light Company	Alliant Energy Corporation	29,928	173,459	16,662,731
2017Y	Interstate Power and Light Company	Alliant Energy Corporation	34,379	259,309	17,406,995
2013Y	Wisconsin Power and Light Company	Alliant Energy Corporation	26,106	105,645	14,862,652
2014Y	Wisconsin Power and Light Company	Alliant Energy Corporation	26,389	109,817	14,603,712
2015Y	Wisconsin Power and Light Company	Alliant Energy Corporation	28,778	96,376	15,199,013
2016Y	Wisconsin Power and Light Company	Alliant Energy Corporation	26,421	124,143	14,480,783
2017Y	Wisconsin Power and Light Company	Alliant Energy Corporation	28,540	178,661	14,165,666
2013Y	Ameren Illinois Company	Ameren Corporation	207,143	250,806	38,012,834
2014Y	Ameren Illinois Company	Ameren Corporation	224,109	278,301	37,915,282
2015Y	Ameren Illinois Company	Ameren Corporation	241,816	388,443	36,850,871
2016Y	Ameren Illinois Company	Ameren Corporation	249,492	353,320	36,754,294
2017Y	Ameren Illinois Company	Ameren Corporation	238,697	379,177	35,537,431
2013Y	Union Electric Company	Ameren Corporation	167,177	206,199	43,158,138
2014Y	Union Electric Company	Ameren Corporation	160,869	241,888	43,192,724
2015Y	Union Electric Company	Ameren Corporation	149,481	202,503	43,255,846
2016Y	Union Electric Company	Ameren Corporation	136,774	295,438	39,997,209
2017Y	Union Electric Company	Ameren Corporation	139,888	242,927	42,237,635
2013Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2014Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	47,215,732
2015Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2016Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2017Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA
2013Y	AEP Texas Central Company	American Electric Power Company, Inc.	62,071	196,024	NA
2014Y	AEP Texas Central Company	American Electric Power Company, Inc.	69,234	174,479	NA
2015Y	AEP Texas Central Company	American Electric Power Company, Inc.	77,322	172,350	NA

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Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2016Y	AEP Texas Central Company	American Electric Power Company, Inc.	68,675	182,424	NA
2017Y	AEP Texas Central Company	American Electric Power Company, Inc.	NA	NA	NA
2013Y	AEP Texas North Company	American Electric Power Company, Inc.	19,547	43,937	2,435,181
2014Y	AEP Texas North Company	American Electric Power Company, Inc.	24,254	56,654	1,741,758
2015Y	AEP Texas North Company	American Electric Power Company, Inc.	29,113	59,762	1,368,742
2016Y	AEP Texas North Company	American Electric Power Company, Inc.	22,061	52,971	1,381,295
2017Y	AEP Texas North Company	American Electric Power Company, Inc.	NA	NA	NA
2013Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2014Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2015Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2016Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA
2017Y	AEP Texas, Inc.	American Electric Power Company, Inc.	97,321	249,463	923,791
2013Y	Appalachian Power Company	American Electric Power Company, Inc.	168,579	185,628	47,596,529
2014Y	Appalachian Power Company	American Electric Power Company, Inc.	123,923	147,800	35,769,358
2015Y	Appalachian Power Company	American Electric Power Company, Inc.	139,749	175,404	34,847,578
2016Y	Appalachian Power Company	American Electric Power Company, Inc.	158,709	202,718	34,862,820
2017Y	Appalachian Power Company	American Electric Power Company, Inc.	148,298	238,727	33,601,395
2013Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	55,467	91,758	38,036,953
2014Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	64,522	87,507	35,331,017
2015Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	56,683	106,776	30,404,900
2016Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	67,671	120,617	28,379,413
2017Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	67,239	187,563	29,819,953
2013Y	Kentucky Power Company	American Electric Power Company, Inc.	39,261	49,458	9,933,527
2014Y	Kentucky Power Company	American Electric Power Company, Inc.	45,049	41,495	11,993,933
2015Y	Kentucky Power Company	American Electric Power Company, Inc.	47,371	38,204	8,700,986
2016Y	Kentucky Power Company	American Electric Power Company, Inc.	49,489	36,074	7,276,047
2017Y	Kentucky Power Company	American Electric Power Company, Inc.	48,993	39,656	7,106,360
2013Y	Kingsport Power Company	American Electric Power Company, Inc.	5,316	11,563	2,045,738
2014Y	Kingsport Power Company	American Electric Power Company, Inc.	3,693	7,045	2,120,716

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Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Kingsport Power Company	American Electric Power Company, Inc.	4,035	12,122	2,086,994
2016Y	Kingsport Power Company	American Electric Power Company, Inc.	5,439	8,475	2,038,552
2017Y	Kingsport Power Company	American Electric Power Company, Inc.	5,231	9,514	1,971,080
2013Y	Ohio Power Company	American Electric Power Company, Inc.	136,596	210,570	60,639,578
2014Y	Ohio Power Company	American Electric Power Company, Inc.	187,981	255,520	15,591,760
2015Y	Ohio Power Company	American Electric Power Company, Inc.	189,705	271,497	45,685,751
2016Y	Ohio Power Company	American Electric Power Company, Inc.	192,513	229,541	45,870,876
2017Y	Ohio Power Company	American Electric Power Company, Inc.	177,929	224,804	45,688,514
2013Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	73,808	143,570	19,239,394
2014Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	68,452	130,480	19,517,893
2015Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	71,355	175,607	18,916,965
2016Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	81,312	166,948	19,425,199
2017Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	97,537	155,889	19,052,676
2013Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	68,828	115,513	28,553,233
2014Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	73,292	77,000	28,644,882
2015Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	84,126	95,004	27,269,400
2016Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	77,198	99,450	26,169,526
2017Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	85,913	103,996	26,257,034
2013Y	Wheeling Power Company	American Electric Power Company, Inc.	5,670	18,386	2,703,781
2014Y	Wheeling Power Company	American Electric Power Company, Inc.	3,571	10,881	3,269,892
2015Y	Wheeling Power Company	American Electric Power Company, Inc.	6,399	8,627	4,451,364
2016Y	Wheeling Power Company	American Electric Power Company, Inc.	7,756	11,839	5,106,836
2017Y	Wheeling Power Company	American Electric Power Company, Inc.	9,025	10,858	5,015,316
2013Y	Alaska Electric Light and Power Company	Avista Corporation	2,848	1,199	377,005
2014Y	Alaska Electric Light and Power Company	Avista Corporation	2,772	1,849	422,784
2015Y	Alaska Electric Light and Power Company	Avista Corporation	2,755	1,357	398,066
2016Y	Alaska Electric Light and Power Company	Avista Corporation	2,877	1,325	395,154
2017Y	Alaska Electric Light and Power Company	Avista Corporation	3,148	1,190	414,210
2013Y	Avista Corporation	Avista Corporation	31,871	72,181	13,318,994

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2014Y	Avista Corporation	Avista Corporation	32,653	79,545	12,839,533
2015Y	Avista Corporation	Avista Corporation	35,900	109,014	11,942,035
2016Y	Avista Corporation	Avista Corporation	32,193	91,970	11,733,626
2017Y	Avista Corporation	Avista Corporation	32,837	101,978	11,980,805
2013Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	11,472	8,814	881,022
2014Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	13,418	4,749	845,665
2015Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	13,330	7,524	844,127
2016Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	12,958	4,392	831,622
2017Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	13,964	10,507	745,193
2013Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	92,116	122,563	32,680,735
2014Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	92,165	148,208	32,499,927
2015Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	82,796	133,032	31,832,657
2016Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	79,336	138,076	32,475,023
2017Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	88,643	161,635	33,727,302
2013Y	Nevada Power Company	Berkshire Hathaway Inc.	37,296	66,956	24,064,426
2014Y	Nevada Power Company	Berkshire Hathaway Inc.	38,593	101,659	22,745,488
2015Y	Nevada Power Company	Berkshire Hathaway Inc.	24,900	110,190	25,481,621
2016Y	Nevada Power Company	Berkshire Hathaway Inc.	25,690	121,544	25,062,084
2017Y	Nevada Power Company	Berkshire Hathaway Inc.	26,906	99,376	23,751,206
2013Y	PacifiCorp	Berkshire Hathaway Inc.	208,439	199,692	65,869,008
2014Y	PacifiCorp	Berkshire Hathaway Inc.	207,564	197,377	65,269,524
2015Y	PacifiCorp	Berkshire Hathaway Inc.	207,035	223,383	63,530,663
2016Y	PacifiCorp	Berkshire Hathaway Inc.	196,498	219,708	60,958,902
2017Y	PacifiCorp	Berkshire Hathaway Inc.	197,649	230,721	62,468,319
2013Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	22,969	55,966	9,185,572
2014Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	21,817	44,586	8,882,408
2015Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	23,601	64,835	8,911,051
2016Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	24,350	49,308	9,000,293
2017Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	26,965	52,920	9,198,853

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2013Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	13,022	12,951	2,028,643
2014Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	13,318	15,895	1,957,695
2015Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	13,782	25,912	1,959,505
2016Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	13,688	18,343	1,985,177
2017Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	14,735	21,674	1,932,972
2013Y	Black Hills Power, Inc.	Black Hills Corporation	8,902	14,230	3,084,298
2014Y	Black Hills Power, Inc.	Black Hills Corporation	9,814	22,117	2,905,098
2015Y	Black Hills Power, Inc.	Black Hills Corporation	9,615	18,714	2,873,371
2016Y	Black Hills Power, Inc.	Black Hills Corporation	10,470	12,816	2,611,946
2017Y	Black Hills Power, Inc.	Black Hills Corporation	12,668	12,680	2,992,386
2013Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	2,904	9,257	1,635,140
2014Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	3,433	8,429	1,639,680
2015Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	3,449	12,930	1,418,697
2016Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	3,634	7,190	1,559,870
2017Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	4,296	12,987	1,647,647
2013Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	33,895	51,951	4,853,495
2014Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	33,687	41,479	4,713,347
2015Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	32,541	36,390	4,751,076
2016Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	35,159	52,948	4,688,744
2017Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	36,333	48,367	4,633,551
2013Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	215,490	306,547	79,984,965
2014Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	233,541	409,069	81,839,060
2015Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	229,591	507,692	84,190,647
2016Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	238,421	423,848	86,828,900
2017Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	243,119	420,164	88,636,417
2013Y	Cleco Power LLC	Cleco Partners LP	28,603	117,936	11,115,732
2014Y	Cleco Power LLC	Cleco Partners LP	29,011	59,926	12,201,940
2015Y	Cleco Power LLC	Cleco Partners LP	30,537	64,581	12,105,640
2016Y	Cleco Power LLC	Cleco Partners LP	30,383	63,967	11,596,427

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2017Y	Cleco Power LLC	Cleco Partners LP	30,776	68,746	11,279,584
2013Y	Consumers Energy Company	CMS Energy Corporation	203,882	350,005	35,276,791
2014Y	Consumers Energy Company	CMS Energy Corporation	183,778	382,396	35,893,242
2015Y	Consumers Energy Company	CMS Energy Corporation	171,489	413,482	36,357,438
2016Y	Consumers Energy Company	CMS Energy Corporation	167,789	486,494	36,746,531
2017Y	Consumers Energy Company	CMS Energy Corporation	185,797	551,042	36,119,073
2013Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	474,143	866,299	47,335,320
2014Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	512,137	1,350,617	46,406,542
2015Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	535,169	1,189,676	47,202,850
2016Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	512,680	1,254,844	47,450,242
2017Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	518,530	1,116,810	46,342,045
2013Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	50,834	50,381	4,263,699
2014Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	52,867	59,950	4,256,408
2015Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	54,299	46,401	4,415,840
2016Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	49,098	52,382	4,315,576
2017Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	50,566	45,382	4,056,841
2013Y	Rockland Electric Company	Consolidated Edison, Inc.	11,459	20,568	1,642,857
2014Y	Rockland Electric Company	Consolidated Edison, Inc.	11,980	8,919	1,610,904
2015Y	Rockland Electric Company	Consolidated Edison, Inc.	16,293	8,803	1,631,351
2016Y	Rockland Electric Company	Consolidated Edison, Inc.	18,771	32,095	1,601,861
2017Y	Rockland Electric Company	Consolidated Edison, Inc.	18,861	14,997	1,538,962
2013Y	Virginia Electric and Power Company	Dominion Energy, Inc.	185,193	500,016	82,852,117
2014Y	Virginia Electric and Power Company	Dominion Energy, Inc.	174,005	528,803	83,938,195
2015Y	Virginia Electric and Power Company	Dominion Energy, Inc.	178,553	638,659	85,178,907
2016Y	Virginia Electric and Power Company	Dominion Energy, Inc.	240,017	625,355	87,875,099
2017Y	Virginia Electric and Power Company	Dominion Energy, Inc.	193,283	686,916	84,969,889
2013Y	Duquesne Light Company	DQE Holdings LLC	39,294	118,856	14,007,273
2014Y	Duquesne Light Company	DQE Holdings LLC	42,059	120,190	13,747,339
2015Y	Duquesne Light Company	DQE Holdings LLC	43,206	122,883	13,503,863

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2016Y	Duquesne Light Company	DQE Holdings LLC	47,867	125,143	13,172,591
2017Y	Duquesne Light Company	DQE Holdings LLC	41,523	166,434	12,696,823
2013Y	DTE Electric Company	DTE Energy Company	308,569	314,418	47,062,371
2014Y	DTE Electric Company	DTE Energy Company	292,153	449,127	46,076,577
2015Y	DTE Electric Company	DTE Energy Company	267,184	443,164	46,281,765
2016Y	DTE Electric Company	DTE Energy Company	283,327	441,562	45,998,164
2017Y	DTE Electric Company	DTE Energy Company	304,550	539,492	44,946,216
2013Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	191,804	389,738	85,789,697
2014Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	244,244	414,986	87,645,520
2015Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	244,757	467,466	87,375,571
2016Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	270,760	554,486	88,544,715
2017Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	276,189	733,301	87,306,564
2013Y	Duke Energy Florida, LLC	Duke Energy Corporation	135,030	205,839	38,164,155
2014Y	Duke Energy Florida, LLC	Duke Energy Corporation	146,828	216,051	38,728,049
2015Y	Duke Energy Florida, LLC	Duke Energy Corporation	150,197	332,870	39,989,379
2016Y	Duke Energy Florida, LLC	Duke Energy Corporation	148,788	359,491	40,660,935
2017Y	Duke Energy Florida, LLC	Duke Energy Corporation	149,549	405,085	40,290,293
2013Y	Duke Energy Indiana, LLC	Duke Energy Corporation	78,965	114,687	33,714,982
2014Y	Duke Energy Indiana, LLC	Duke Energy Corporation	82,121	123,445	33,433,620
2015Y	Duke Energy Indiana, LLC	Duke Energy Corporation	91,194	167,360	33,517,569
2016Y	Duke Energy Indiana, LLC	Duke Energy Corporation	99,680	173,160	34,368,826
2017Y	Duke Energy Indiana, LLC	Duke Energy Corporation	99,541	272,420	33,145,670
2013Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	10,273	15,744	4,546,692
2014Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	11,669	18,659	4,447,988
2015Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	12,448	22,197	5,277,786
2016Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	12,929	19,097	4,672,987
2017Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	18,190	34,942	4,908,072
2013Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	57,544	113,700	39,309,749
2014Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	62,768	80,946	27,741,596

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2015Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	68,231	105,920	20,805,363
2016Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	82,036	180,888	21,320,518
2017Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	94,330	205,811	20,805,946
2013Y	Duke Energy Progress, LLC	Duke Energy Corporation	130,114	179,180	60,204,063
2014Y	Duke Energy Progress, LLC	Duke Energy Corporation	178,322	242,406	62,871,047
2015Y	Duke Energy Progress, LLC	Duke Energy Corporation	138,636	341,230	64,880,560
2016Y	Duke Energy Progress, LLC	Duke Energy Corporation	165,907	417,747	69,052,154
2017Y	Duke Energy Progress, LLC	Duke Energy Corporation	153,498	456,462	66,822,736
2013Y	Southern California Edison Company	Edison International	461,916	1,137,078	90,552,978
2014Y	Southern California Edison Company	Edison International	494,881	1,534,333	116,437,195
2015Y	Southern California Edison Company	Edison International	497,566	1,822,203	90,495,397
2016Y	Southern California Edison Company	Edison International	523,427	1,615,936	88,194,998
2017Y	Southern California Edison Company	Edison International	523,406	1,608,680	91,291,726
2013Y	El Paso Electric Company	El Paso Electric Company	21,740	54,441	10,884,241
2014Y	El Paso Electric Company	El Paso Electric Company	22,321	69,379	11,009,422
2015Y	El Paso Electric Company	El Paso Electric Company	22,881	56,155	10,915,601
2016Y	El Paso Electric Company	El Paso Electric Company	22,669	65,908	10,598,511
2017Y	El Paso Electric Company	El Paso Electric Company	22,224	65,506	10,904,754
2013Y	Emera Maine	Emera Incorporated	10,006	10,567	1,869,923
2014Y	Emera Maine	Emera Incorporated	16,828	110,544	2,344,241
2015Y	Emera Maine	Emera Incorporated	16,512	21,550	2,325,046
2016Y	Emera Maine	Emera Incorporated	17,269	31,711	2,217,874
2017Y	Emera Maine	Emera Incorporated	16,947	35,705	2,270,073
2013Y	Maine Public Service Company	Emera Incorporated	3,606	4,781	NA
2014Y	Maine Public Service Company	Emera Incorporated	NA	NA	NA
2015Y	Maine Public Service Company	Emera Incorporated	NA	NA	NA
2016Y	Maine Public Service Company	Emera Incorporated	NA	NA	NA
2017Y	Maine Public Service Company	Emera Incorporated	NA	NA	NA
2013Y	Tampa Electric Company	Emera Incorporated	48,426	118,551	18,639,927

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2014Y	Tampa Electric Company	Emera Incorporated	49,304	115,200	18,784,911
2015Y	Tampa Electric Company	Emera Incorporated	52,920	115,088	19,121,762
2016Y	Tampa Electric Company	Emera Incorporated	52,325	143,592	19,440,142
2017Y	Tampa Electric Company	Emera Incorporated	48,089	139,654	19,425,418
2013Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2014Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2015Y	EL Investment Company, LLC	Entergy Corporation	41,061	84,622	31,482,380
2016Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2017Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA
2013Y	Entergy Arkansas, Inc.	Entergy Corporation	59,067	156,217	29,788,956
2014Y	Entergy Arkansas, Inc.	Entergy Corporation	68,806	166,914	31,350,781
2015Y	Entergy Arkansas, Inc.	Entergy Corporation	84,018	142,038	31,379,457
2016Y	Entergy Arkansas, Inc.	Entergy Corporation	77,522	228,616	29,363,790
2017Y	Entergy Arkansas, Inc.	Entergy Corporation	85,182	170,888	29,219,532
2013Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	26,253	29,597	27,130,595
2014Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	25,398	80,050	28,713,874
2015Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	21,667	41,746	21,426,698
2016Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA
2017Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA
2013Y	Entergy Louisiana, LLC	Entergy Corporation	49,808	30,529	34,156,904
2014Y	Entergy Louisiana, LLC	Entergy Corporation	51,360	91,251	37,479,888
2015Y	Entergy Louisiana, LLC	Entergy Corporation	21,714	57,759	14,743,976
2016Y	Entergy Louisiana, LLC	Entergy Corporation	80,745	247,871	63,634,403
2017Y	Entergy Louisiana, LLC	Entergy Corporation	87,570	222,180	61,747,129
2013Y	Entergy Mississippi, Inc.	Entergy Corporation	42,432	85,913	14,965,739
2014Y	Entergy Mississippi, Inc.	Entergy Corporation	33,675	78,897	16,054,977
2015Y	Entergy Mississippi, Inc.	Entergy Corporation	40,332	89,475	14,969,217
2016Y	Entergy Mississippi, Inc.	Entergy Corporation	44,578	126,882	14,462,253
2017Y	Entergy Mississippi, Inc.	Entergy Corporation	47,296	125,919	13,904,918

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2013Y	Entergy New Orleans, LLC	Entergy Corporation	9,764	26,176	5,615,573
2014Y	Entergy New Orleans, LLC	Entergy Corporation	11,673	32,651	6,570,789
2015Y	Entergy New Orleans, LLC	Entergy Corporation	10,522	11,079	7,138,626
2016Y	Entergy New Orleans, LLC	Entergy Corporation	12,626	31,681	6,947,771
2017Y	Entergy New Orleans, LLC	Entergy Corporation	16,854	45,497	7,327,377
2013Y	Entergy Texas, Inc.	Entergy Corporation	34,215	74,664	23,811,698
2014Y	Entergy Texas, Inc.	Entergy Corporation	33,681	78,551	22,661,605
2015Y	Entergy Texas, Inc.	Entergy Corporation	34,046	84,301	23,855,503
2016Y	Entergy Texas, Inc.	Entergy Corporation	32,599	103,503	23,892,632
2017Y	Entergy Texas, Inc.	Entergy Corporation	37,702	104,057	20,321,420
2013Y	Connecticut Light and Power Company	Eversource Energy	143,521	274,402	23,299,945
2014Y	Connecticut Light and Power Company	Eversource Energy	152,990	253,325	22,647,162
2015Y	Connecticut Light and Power Company	Eversource Energy	148,411	248,804	22,643,456
2016Y	Connecticut Light and Power Company	Eversource Energy	158,485	306,517	22,342,433
2017Y	Connecticut Light and Power Company	Eversource Energy	176,464	347,614	21,611,697
2013Y	NSTAR Electric Company	Eversource Energy	126,695	186,136	23,996,935
2014Y	NSTAR Electric Company	Eversource Energy	112,493	227,266	23,629,876
2015Y	NSTAR Electric Company	Eversource Energy	104,053	207,947	23,856,657
2016Y	NSTAR Electric Company	Eversource Energy	111,750	292,731	23,127,763
2017Y	NSTAR Electric Company	Eversource Energy	98,772	197,349	21,529,739
2013Y	Public Service Company of New Hampshire	Eversource Energy	60,787	81,052	9,118,546
2014Y	Public Service Company of New Hampshire	Eversource Energy	58,180	103,440	8,595,895
2015Y	Public Service Company of New Hampshire	Eversource Energy	64,753	106,451	8,441,532
2016Y	Public Service Company of New Hampshire	Eversource Energy	66,977	145,558	8,388,691
2017Y	Public Service Company of New Hampshire	Eversource Energy	71,005	132,127	8,116,389
2013Y	Western Massachusetts Electric Company	Eversource Energy	22,921	35,212	3,724,299
2014Y	Western Massachusetts Electric Company	Eversource Energy	23,900	29,657	3,610,361
2015Y	Western Massachusetts Electric Company	Eversource Energy	21,812	37,734	3,601,321
2016Y	Western Massachusetts Electric Company	Eversource Energy	24,128	28,226	3,706,255

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2017Y	Western Massachusetts Electric Company	Eversource Energy	23,185	39,224	3,689,391
2013Y	Atlantic City Electric Company	Exelon Corporation	59,421	130,114	11,562,281
2014Y	Atlantic City Electric Company	Exelon Corporation	66,772	123,264	11,658,993
2015Y	Atlantic City Electric Company	Exelon Corporation	72,953	90,123	11,225,247
2016Y	Atlantic City Electric Company	Exelon Corporation	87,419	84,930	10,723,259
2017Y	Atlantic City Electric Company	Exelon Corporation	91,245	129,933	9,822,917
2013Y	Baltimore Gas and Electric Company	Exelon Corporation	173,989	361,673	30,767,778
2014Y	Baltimore Gas and Electric Company	Exelon Corporation	208,530	238,478	30,562,078
2015Y	Baltimore Gas and Electric Company	Exelon Corporation	187,276	245,153	30,304,293
2016Y	Baltimore Gas and Electric Company	Exelon Corporation	235,527	233,269	30,019,586
2017Y	Baltimore Gas and Electric Company	Exelon Corporation	199,723	196,635	28,970,770
2013Y	Commonwealth Edison Company	Exelon Corporation	438,781	782,667	93,089,440
2014Y	Commonwealth Edison Company	Exelon Corporation	466,699	967,798	90,578,581
2015Y	Commonwealth Edison Company	Exelon Corporation	465,652	1,304,735	87,297,520
2016Y	Commonwealth Edison Company	Exelon Corporation	469,753	1,551,281	89,608,490
2017Y	Commonwealth Edison Company	Exelon Corporation	465,285	1,369,475	87,568,519
2013Y	Delmarva Power & Light Company	Exelon Corporation	56,785	165,494	12,817,180
2014Y	Delmarva Power & Light Company	Exelon Corporation	72,681	160,980	12,782,957
2015Y	Delmarva Power & Light Company	Exelon Corporation	75,338	134,680	12,805,844
2016Y	Delmarva Power & Light Company	Exelon Corporation	83,796	119,135	12,486,406
2017Y	Delmarva Power & Light Company	Exelon Corporation	84,765	142,450	12,222,536
2013Y	PECO Energy Company	Exelon Corporation	200,354	306,220	38,044,130
2014Y	PECO Energy Company	Exelon Corporation	315,412	329,379	37,681,485
2015Y	PECO Energy Company	Exelon Corporation	248,456	272,951	38,124,845
2016Y	PECO Energy Company	Exelon Corporation	261,731	261,061	37,940,620
2017Y	PECO Energy Company	Exelon Corporation	262,335	281,032	37,233,657
2013Y	Potomac Electric Power Company	Exelon Corporation	124,164	385,985	25,807,813
2014Y	Potomac Electric Power Company	Exelon Corporation	121,596	406,471	25,750,549
2015Y	Potomac Electric Power Company	Exelon Corporation	134,876	353,223	25,987,432

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Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Potomac Electric Power Company	Exelon Corporation	158,378	276,139	26,114,290
2017Y	Potomac Electric Power Company	Exelon Corporation	155,657	434,471	24,855,893
2013Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	35,046	87,701	18,712,244
2014Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	36,239	86,647	18,733,302
2015Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	42,854	83,331	18,501,986
2016Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	47,827	105,434	18,817,928
2017Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	53,813	96,725	18,290,574
2013Y	Jersey Central Power & Light Company	FirstEnergy Corp.	102,374	151,695	21,836,806
2014Y	Jersey Central Power & Light Company	FirstEnergy Corp.	87,115	173,742	21,846,258
2015Y	Jersey Central Power & Light Company	FirstEnergy Corp.	106,069	206,136	21,332,986
2016Y	Jersey Central Power & Light Company	FirstEnergy Corp.	95,301	204,648	21,250,880
2017Y	Jersey Central Power & Light Company	FirstEnergy Corp.	93,750	154,814	20,535,764
2013Y	Metropolitan Edison Company	FirstEnergy Corp.	36,657	67,415	14,226,643
2014Y	Metropolitan Edison Company	FirstEnergy Corp.	51,433	101,674	14,276,774
2015Y	Metropolitan Edison Company	FirstEnergy Corp.	39,665	88,633	14,291,940
2016Y	Metropolitan Edison Company	FirstEnergy Corp.	45,464	100,463	14,143,059
2017Y	Metropolitan Edison Company	FirstEnergy Corp.	51,442	112,504	13,777,426
2013Y	Monongahela Power Company	FirstEnergy Corp.	34,233	75,907	10,816,852
2014Y	Monongahela Power Company	FirstEnergy Corp.	60,903	79,074	17,361,198
2015Y	Monongahela Power Company	FirstEnergy Corp.	67,261	87,372	16,163,874
2016Y	Monongahela Power Company	FirstEnergy Corp.	65,326	82,242	17,434,322
2017Y	Monongahela Power Company	FirstEnergy Corp.	65,980	95,803	17,497,075
2013Y	Ohio Edison Company	FirstEnergy Corp.	58,468	114,168	27,059,942
2014Y	Ohio Edison Company	FirstEnergy Corp.	54,947	121,864	27,819,394
2015Y	Ohio Edison Company	FirstEnergy Corp.	56,758	114,984	27,056,153
2016Y	Ohio Edison Company	FirstEnergy Corp.	54,428	109,994	26,451,421
2017Y	Ohio Edison Company	FirstEnergy Corp.	74,846	98,189	23,977,058
2013Y	Pennsylvania Electric Company	FirstEnergy Corp.	41,874	95,006	15,484,578
2014Y	Pennsylvania Electric Company	FirstEnergy Corp.	42,236	103,508	14,771,582

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Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Pennsylvania Electric Company	FirstEnergy Corp.	43,420	92,701	14,473,442
2016Y	Pennsylvania Electric Company	FirstEnergy Corp.	44,600	137,435	14,386,263
2017Y	Pennsylvania Electric Company	FirstEnergy Corp.	65,175	124,714	14,363,454
2013Y	Pennsylvania Power Company	FirstEnergy Corp.	13,245	22,620	4,567,609
2014Y	Pennsylvania Power Company	FirstEnergy Corp.	12,063	35,005	4,714,488
2015Y	Pennsylvania Power Company	FirstEnergy Corp.	12,443	53,076	4,526,159
2016Y	Pennsylvania Power Company	FirstEnergy Corp.	12,053	48,083	4,615,081
2017Y	Pennsylvania Power Company	FirstEnergy Corp.	16,137	49,940	4,633,922
2013Y	Potomac Edison Company	FirstEnergy Corp.	26,135	71,187	11,862,840
2014Y	Potomac Edison Company	FirstEnergy Corp.	42,664	60,676	11,898,341
2015Y	Potomac Edison Company	FirstEnergy Corp.	33,403	60,897	11,823,082
2016Y	Potomac Edison Company	FirstEnergy Corp.	32,613	73,657	11,554,451
2017Y	Potomac Edison Company	FirstEnergy Corp.	31,397	72,714	11,322,812
2013Y	Toledo Edison Company	FirstEnergy Corp.	17,264	26,853	11,956,365
2014Y	Toledo Edison Company	FirstEnergy Corp.	16,372	38,991	11,873,197
2015Y	Toledo Edison Company	FirstEnergy Corp.	19,736	33,332	11,779,382
2016Y	Toledo Edison Company	FirstEnergy Corp.	17,331	36,645	12,079,562
2017Y	Toledo Edison Company	FirstEnergy Corp.	19,936	27,191	10,856,745
2013Y	West Penn Power Company	FirstEnergy Corp.	37,859	110,210	20,052,177
2014Y	West Penn Power Company	FirstEnergy Corp.	38,564	81,148	20,291,236
2015Y	West Penn Power Company	FirstEnergy Corp.	54,854	94,485	20,083,013
2016Y	West Penn Power Company	FirstEnergy Corp.	48,706	130,113	19,998,876
2017Y	West Penn Power Company	FirstEnergy Corp.	67,502	137,615	19,616,843
2013Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	44,377	45,480	2,761,676
2014Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	44,142	35,593	2,623,309
2015Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	44,594	52,511	2,608,207
2016Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	44,997	49,968	2,684,357
2017Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	50,433	49,711	2,602,989
2013Y	Tucson Electric Power Company	Fortis Inc.	21,731	57,690	13,025,375

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2014Y	Tucson Electric Power Company	Fortis Inc.	24,117	71,192	13,311,011
2015Y	Tucson Electric Power Company	Fortis Inc.	22,407	76,080	14,279,396
2016Y	Tucson Electric Power Company	Fortis Inc.	23,432	65,102	13,718,397
2017Y	Tucson Electric Power Company	Fortis Inc.	23,490	66,461	13,442,595
2013Y	UNS Electric, Inc.	Fortis Inc.	6,076	9,584	2,230,041
2014Y	UNS Electric, Inc.	Fortis Inc.	5,497	18,143	1,982,714
2015Y	UNS Electric, Inc.	Fortis Inc.	5,245	16,226	1,746,289
2016Y	UNS Electric, Inc.	Fortis Inc.	5,760	18,696	1,762,853
2017Y	UNS Electric, Inc.	Fortis Inc.	6,926	14,596	1,916,799
2013Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	53,615	89,550	21,683,329
2014Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	51,169	137,982	22,472,307
2015Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	53,422	159,751	20,796,733
2016Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	55,971	110,062	21,433,876
2017Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	56,071	111,477	21,322,723
2013Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	29,003	59,334	8,413,828
2014Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	32,301	52,029	8,511,766
2015Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	31,845	68,176	8,385,574
2016Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	34,872	70,091	8,465,650
2017Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	35,072	77,273	8,386,821
2013Y	Central Maine Power Company	Iberdrola, S.A.	101,202	55,111	603,824
2014Y	Central Maine Power Company	Iberdrola, S.A.	95,837	62,111	590,204
2015Y	Central Maine Power Company	Iberdrola, S.A.	95,668	18,842	600,705
2016Y	Central Maine Power Company	Iberdrola, S.A.	95,005	63,971	599,743
2017Y	Central Maine Power Company	Iberdrola, S.A.	97,758	99,396	172,595
2013Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	128,820	93,551	19,115,201
2014Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	140,939	78,076	18,690,994
2015Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	126,688	54,453	17,887,199
2016Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	184,037	53,098	17,455,920
2017Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	230,586	95,728	16,633,428

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2013Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	45,602	53,434	9,024,632
2014Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	46,080	41,357	7,970,527
2015Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	52,426	9,802	7,319,681
2016Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	54,581	21,771	7,365,999
2017Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	65,432	90,175	7,216,272
2013Y	United Illuminating Company	Iberdrola, S.A.	84,008	129,682	5,422,427
2014Y	United Illuminating Company	Iberdrola, S.A.	83,114	171,739	5,327,395
2015Y	United Illuminating Company	Iberdrola, S.A.	98,347	132,046	5,450,238
2016Y	United Illuminating Company	Iberdrola, S.A.	102,068	97,207	5,334,351
2017Y	United Illuminating Company	Iberdrola, S.A.	107,475	54,605	5,093,904
2013Y	Idaho Power Co.	IDACORP, Inc.	46,979	57,666	16,302,681
2014Y	Idaho Power Co.	IDACORP, Inc.	46,305	69,497	16,312,786
2015Y	Idaho Power Co.	IDACORP, Inc.	48,358	77,325	15,518,629
2016Y	Idaho Power Co.	IDACORP, Inc.	50,033	77,748	15,381,629
2017Y	Idaho Power Co.	IDACORP, Inc.	50,643	91,493	16,706,603
2013Y	Kentucky Utilities Company	LKE	56,507	66,870	21,629,993
2014Y	Kentucky Utilities Company	LKE	60,874	87,349	21,986,858
2015Y	Kentucky Utilities Company	LKE	56,957	77,963	21,810,131
2016Y	Kentucky Utilities Company	LKE	57,318	105,455	21,437,963
2017Y	Kentucky Utilities Company	LKE	56,162	83,549	20,497,797
2013Y	Louisville Gas and Electric Company	LKE	46,074	47,343	14,478,316
2014Y	Louisville Gas and Electric Company	LKE	51,335	78,051	15,373,731
2015Y	Louisville Gas and Electric Company	LKE	49,032	78,271	13,502,213
2016Y	Louisville Gas and Electric Company	LKE	46,816	78,681	13,156,493
2017Y	Louisville Gas and Electric Company	LKE	45,209	85,938	13,133,134
2013Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	15,581	33,419	3,195,882
2014Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	15,440	40,430	3,331,202
2015Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	15,747	34,104	3,316,058
2016Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	15,619	25,079	3,303,555

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2017Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	15,355	19,816	3,346,441
2013Y	Madison Gas and Electric Company	MGE Energy, Inc.	14,756	41,569	3,557,446
2014Y	Madison Gas and Electric Company	MGE Energy, Inc.	14,099	35,040	3,514,574
2015Y	Madison Gas and Electric Company	MGE Energy, Inc.	14,141	27,493	3,545,081
2016Y	Madison Gas and Electric Company	MGE Energy, Inc.	14,644	35,044	3,741,999
2017Y	Madison Gas and Electric Company	MGE Energy, Inc.	14,295	37,800	3,584,998
2013Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	1,052	800	99,446
2014Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	1,093	946	99,841
2015Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	1,431	1,097	99,902
2016Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	1,618	1,220	95,751
2017Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	1,757	1,186	95,101
2013Y	Massachusetts Electric Company	National Grid plc	182,207	144,261	11,080,137
2014Y	Massachusetts Electric Company	National Grid plc	154,189	202,739	10,608,963
2015Y	Massachusetts Electric Company	National Grid plc	152,459	267,123	8,699,117
2016Y	Massachusetts Electric Company	National Grid plc	167,144	232,709	6,486,573
2017Y	Massachusetts Electric Company	National Grid plc	158,884	265,180	6,427,679
2013Y	Narragansett Electric Company	National Grid plc	51,188	39,112	5,133,864
2014Y	Narragansett Electric Company	National Grid plc	47,799	74,616	5,006,934
2015Y	Narragansett Electric Company	National Grid plc	40,698	78,670	4,492,267
2016Y	Narragansett Electric Company	National Grid plc	50,220	61,018	3,954,763
2017Y	Narragansett Electric Company	National Grid plc	52,514	73,062	3,868,162
2013Y	New England Power Company	National Grid plc	77	0	570,917
2014Y	New England Power Company	National Grid plc	27	-869	565,418
2015Y	New England Power Company	National Grid plc	35	7,940	566,430
2016Y	New England Power Company	National Grid plc	40	-7,346	314,990
2017Y	New England Power Company	National Grid plc	71	0	239,434
2013Y	Niagara Mohawk Power Corporation	National Grid plc	277,222	187,286	16,348,792
2014Y	Niagara Mohawk Power Corporation	National Grid plc	257,711	324,129	13,620,478
2015Y	Niagara Mohawk Power Corporation	National Grid plc	218,069	346,170	13,464,032

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2016Y	Niagara Mohawk Power Corporation	National Grid plc	239,049	249,747	13,600,814
2017Y	Niagara Mohawk Power Corporation	National Grid plc	289,261	236,450	13,190,657
2013Y	Florida Power & Light Company	NextEra Energy, Inc.	265,813	581,682	107,373,794
2014Y	Florida Power & Light Company	NextEra Energy, Inc.	268,585	737,597	112,929,729
2015Y	Florida Power & Light Company	NextEra Energy, Inc.	274,770	1,085,860	119,405,262
2016Y	Florida Power & Light Company	NextEra Energy, Inc.	271,303	1,205,032	119,279,691
2017Y	Florida Power & Light Company	NextEra Energy, Inc.	1,446,795	1,455,591	117,873,183
2013Y	Northern Indiana Public Service Company	NiSource Inc.	48,247	71,715	17,468,011
2014Y	Northern Indiana Public Service Company	NiSource Inc.	43,588	83,457	18,186,288
2015Y	Northern Indiana Public Service Company	NiSource Inc.	41,331	99,516	16,758,427
2016Y	Northern Indiana Public Service Company	NiSource Inc.	43,824	128,135	16,831,194
2017Y	Northern Indiana Public Service Company	NiSource Inc.	49,602	126,817	16,725,564
2013Y	NorthWestern Corporation	NorthWestern Corporation	53,600	73,778	9,519,519
2014Y	NorthWestern Corporation	NorthWestern Corporation	50,360	84,915	10,006,908
2015Y	NorthWestern Corporation	NorthWestern Corporation	49,950	100,394	11,027,880
2016Y	NorthWestern Corporation	NorthWestern Corporation	43,025	89,122	9,037,846
2017Y	NorthWestern Corporation	NorthWestern Corporation	44,613	133,187	8,924,244
2013Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	80,209	198,520	28,578,159
2014Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	80,858	187,793	30,234,927
2015Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	74,150	194,277	28,867,056
2016Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	80,041	184,692	29,762,475
2017Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	96,565	184,907	28,111,471
2013Y	Otter Tail Power Company	Otter Tail Corporation	16,699	18,910	6,219,751
2014Y	Otter Tail Power Company	Otter Tail Corporation	16,511	20,041	5,470,896
2015Y	Otter Tail Power Company	Otter Tail Corporation	15,514	16,797	4,709,464
2016Y	Otter Tail Power Company	Otter Tail Corporation	16,791	17,137	4,955,630
2017Y	Otter Tail Power Company	Otter Tail Corporation	17,762	19,433	5,040,591
2013Y	Pacific Gas and Electric Company	PG&E Corporation	629,019	1,483,663	88,322,913
2014Y	Pacific Gas and Electric Company	PG&E Corporation	675,094	1,277,867	88,189,685

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2015Y	Pacific Gas and Electric Company	PG&E Corporation	829,694	1,504,948	87,981,023
2016Y	Pacific Gas and Electric Company	PG&E Corporation	933,331	1,508,269	85,067,412
2017Y	Pacific Gas and Electric Company	PG&E Corporation	726,324	1,664,690	88,175,650
2013Y	Arizona Public Service Company	Pinnacle West Capital Corporation	96,398	203,565	32,087,545
2014Y	Arizona Public Service Company	Pinnacle West Capital Corporation	92,229	213,685	32,951,388
2015Y	Arizona Public Service Company	Pinnacle West Capital Corporation	95,469	243,885	33,628,854
2016Y	Arizona Public Service Company	Pinnacle West Capital Corporation	104,812	247,452	31,928,046
2017Y	Arizona Public Service Company	Pinnacle West Capital Corporation	109,284	320,175	30,910,170
2013Y	Public Service Company of New Mexico	PNM Resources, Inc.	24,289	63,008	12,001,980
2014Y	Public Service Company of New Mexico	PNM Resources, Inc.	21,773	64,261	11,836,387
2015Y	Public Service Company of New Mexico	PNM Resources, Inc.	22,882	61,865	11,541,512
2016Y	Public Service Company of New Mexico	PNM Resources, Inc.	19,744	60,790	12,280,191
2017Y	Public Service Company of New Mexico	PNM Resources, Inc.	20,667	48,795	12,454,143
2013Y	Portland General Electric Company	Portland General Electric Company	86,417	139,424	21,226,863
2014Y	Portland General Electric Company	Portland General Electric Company	99,839	144,332	21,080,082
2015Y	Portland General Electric Company	Portland General Electric Company	101,417	154,813	20,859,230
2016Y	Portland General Electric Company	Portland General Electric Company	116,611	164,649	21,247,271
2017Y	Portland General Electric Company	Portland General Electric Company	127,637	218,102	21,328,945
2013Y	PPL Electric Utilities Corporation	PPL Corporation	166,294	279,496	37,712,878
2014Y	PPL Electric Utilities Corporation	PPL Corporation	176,101	259,358	38,005,667
2015Y	PPL Electric Utilities Corporation	PPL Corporation	157,935	266,973	37,967,738
2016Y	PPL Electric Utilities Corporation	PPL Corporation	166,677	317,766	37,618,811
2017Y	PPL Electric Utilities Corporation	PPL Corporation	156,585	426,951	36,939,991
2013Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	161,707	367,725	44,103,026
2014Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	169,243	215,303	42,728,622
2015Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	169,001	374,845	43,533,905
2016Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	176,532	486,743	42,288,312
2017Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	169,334	558,016	40,894,038
2013Y	Puget Sound Energy, Inc.	Puget Holdings LLC	77,322	86,240	26,265,216

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2014Y	Puget Sound Energy, Inc.	Puget Holdings LLC	84,585	163,238	21,968,767
2015Y	Puget Sound Energy, Inc.	Puget Holdings LLC	82,427	150,204	28,183,148
2016Y	Puget Sound Energy, Inc.	Puget Holdings LLC	86,298	208,702	29,143,765
2017Y	Puget Sound Energy, Inc.	Puget Holdings LLC	76,282	213,490	27,227,367
2013Y	South Carolina Electric & Gas Co.	SCANA Corporation	46,623	135,213	22,326,578
2014Y	South Carolina Electric & Gas Co.	SCANA Corporation	51,470	125,185	23,332,942
2015Y	South Carolina Electric & Gas Co.	SCANA Corporation	56,138	135,005	23,114,845
2016Y	South Carolina Electric & Gas Co.	SCANA Corporation	55,248	154,146	23,471,194
2017Y	South Carolina Electric & Gas Co.	SCANA Corporation	55,485	119,637	22,879,069
2013Y	Oncor Electric Delivery Company LLC	Sempra Energy	191,839	394,462	112,312,279
2014Y	Oncor Electric Delivery Company LLC	Sempra Energy	200,557	436,384	114,905,829
2015Y	Oncor Electric Delivery Company LLC	Sempra Energy	236,440	537,277	116,594,625
2016Y	Oncor Electric Delivery Company LLC	Sempra Energy	250,555	621,144	115,791,379
2017Y	Oncor Electric Delivery Company LLC	Sempra Energy	252,411	705,889	117,017,075
2013Y	San Diego Gas & Electric Co.	Sempra Energy	128,782	242,705	32,916,382
2014Y	San Diego Gas & Electric Co.	Sempra Energy	112,219	259,549	30,952,957
2015Y	San Diego Gas & Electric Co.	Sempra Energy	141,442	361,852	33,132,033
2016Y	San Diego Gas & Electric Co.	Sempra Energy	141,031	341,598	29,443,890
2017Y	San Diego Gas & Electric Co.	Sempra Energy	144,376	443,069	29,300,970
2013Y	Alabama Power Company	Southern Company	170,411	287,329	66,309,626
2014Y	Alabama Power Company	Southern Company	188,700	321,366	67,155,314
2015Y	Alabama Power Company	Southern Company	177,116	301,021	63,847,336
2016Y	Alabama Power Company	Southern Company	184,276	346,170	63,873,423
2017Y	Alabama Power Company	Southern Company	239,283	408,891	63,290,561
2013Y	Georgia Power Company	Southern Company	237,660	351,116	84,726,779
2014Y	Georgia Power Company	Southern Company	302,102	414,508	89,190,865
2015Y	Georgia Power Company	Southern Company	276,806	432,873	87,859,128
2016Y	Georgia Power Company	Southern Company	302,244	521,749	89,686,468
2017Y	Georgia Power Company	Southern Company	268,673	568,705	86,478,222

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2013Y	Gulf Power Company	Southern Company	42,915	71,849	14,909,545
2014Y	Gulf Power Company	Southern Company	46,843	61,302	16,028,868
2015Y	Gulf Power Company	Southern Company	45,678	56,040	14,031,937
2016Y	Gulf Power Company	Southern Company	45,456	57,848	14,616,769
2017Y	Gulf Power Company	Southern Company	48,030	63,408	15,445,454
2013Y	Mississippi Power Company	Southern Company	34,358	34,770	14,591,834
2014Y	Mississippi Power Company	Southern Company	36,912	35,685	17,059,643
2015Y	Mississippi Power Company	Southern Company	32,805	48,948	16,487,788
2016Y	Mississippi Power Company	Southern Company	36,118	35,587	14,866,485
2017Y	Mississippi Power Company	Southern Company	31,566	40,129	15,283,882
2013Y	UGI Utilities, Inc.	UGI Corporation	5,952	5,198	1,000,701
2014Y	UGI Utilities, Inc.	UGI Corporation	7,773	5,183	975,771
2015Y	UGI Utilities, Inc.	UGI Corporation	6,669	5,480	990,384
2016Y	UGI Utilities, Inc.	UGI Corporation	7,012	4,908	977,118
2017Y	UGI Utilities, Inc.	UGI Corporation	6,994	9,969	956,654
2013Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,318	4,521	505,418
2014Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,960	4,903	533,929
2015Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,680	7,246	460,811
2016Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,714	7,911	444,498
2017Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	4,363	7,327	455,496
2013Y	Unitil Energy Systems, Inc.	Unitil Corporation	9,592	15,524	1,234,354
2014Y	Unitil Energy Systems, Inc.	Unitil Corporation	8,801	13,803	1,230,055
2015Y	Unitil Energy Systems, Inc.	Unitil Corporation	9,010	12,567	1,229,879
2016Y	Unitil Energy Systems, Inc.	Unitil Corporation	8,719	23,715	1,203,404
2017Y	Unitil Energy Systems, Inc.	Unitil Corporation	9,126	28,127	1,215,797
2013Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	15,196	22,238	5,993,477
2014Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	15,881	27,090	6,240,584
2015Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	15,461	31,883	5,795,918
2016Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	15,350	31,886	5,610,259

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	16,055	46,975	5,220,819
2013Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	92,452	190,113	32,555,334
2014Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	80,131	216,010	32,942,828
2015Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	80,602	238,644	35,818,700
2016Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	92,874	252,002	35,894,209
2017Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	78,376	287,164	34,951,750
2013Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	46,236	37,798	16,129,893
2014Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	51,622	62,710	14,557,949
2015Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	52,052	94,857	14,839,077
2016Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	37,348	112,114	14,636,889
2017Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	32,803	148,711	14,814,995
2013Y	Kansas Gas and Electric Company	Westar Energy, Inc.	41,913	26,896	10,605,055
2014Y	Kansas Gas and Electric Company	Westar Energy, Inc.	45,361	56,626	10,800,465
2015Y	Kansas Gas and Electric Company	Westar Energy, Inc.	36,881	58,332	10,761,626
2016Y	Kansas Gas and Electric Company	Westar Energy, Inc.	42,611	85,473	11,297,034
2017Y	Kansas Gas and Electric Company	Westar Energy, Inc.	40,354	104,586	10,847,878
2013Y	Westar Energy (KPL)	Westar Energy, Inc.	59,147	41,700	17,484,374
2014Y	Westar Energy (KPL)	Westar Energy, Inc.	49,269	76,430	18,531,716
2015Y	Westar Energy (KPL)	Westar Energy, Inc.	49,632	104,404	17,180,535
2016Y	Westar Energy (KPL)	Westar Energy, Inc.	45,165	123,111	16,555,817
2017Y	Westar Energy (KPL)	Westar Energy, Inc.	42,538	93,589	18,790,662
2013Y	Northern States Power Company - MN	Xcel Energy Inc.	121,107	171,686	37,474,524
2014Y	Northern States Power Company - MN	Xcel Energy Inc.	117,778	188,375	39,129,144
2015Y	Northern States Power Company - MN	Xcel Energy Inc.	106,452	166,340	39,484,126
2016Y	Northern States Power Company - MN	Xcel Energy Inc.	110,969	206,460	41,519,021
2017Y	Northern States Power Company - MN	Xcel Energy Inc.	111,166	172,861	40,720,489
2013Y	Northern States Power Company - WI	Xcel Energy Inc.	25,725	37,741	6,562,368
2014Y	Northern States Power Company - WI	Xcel Energy Inc.	24,836	47,930	6,750,889
2015Y	Northern States Power Company - WI	Xcel Energy Inc.	24,951	46,180	6,647,300

Notes: "NA" data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Distribution O&M Expense ($000)	Total Distribution Plant: Add ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Northern States Power Company - WI	Xcel Energy Inc.	25,096	45,148	6,641,542
2017Y	Northern States Power Company - WI	Xcel Energy Inc.	26,246	45,576	6,727,740
2013Y	Public Service Company of Colorado	Xcel Energy Inc.	103,101	217,189	33,450,187
2014Y	Public Service Company of Colorado	Xcel Energy Inc.	94,666	239,321	32,498,488
2015Y	Public Service Company of Colorado	Xcel Energy Inc.	92,990	231,178	32,396,474
2016Y	Public Service Company of Colorado	Xcel Energy Inc.	96,620	248,655	34,472,722
2017Y	Public Service Company of Colorado	Xcel Energy Inc.	97,636	235,993	36,486,396
2013Y	Southwestern Public Service Company	Xcel Energy Inc.	35,179	58,439	28,292,788
2014Y	Southwestern Public Service Company	Xcel Energy Inc.	36,160	74,526	28,265,391
2015Y	Southwestern Public Service Company	Xcel Energy Inc.	38,256	107,628	28,414,831
2016Y	Southwestern Public Service Company	Xcel Energy Inc.	30,994	81,287	28,383,129
2017Y	Southwestern Public Service Company	Xcel Energy Inc.	36,120	96,062	27,124,064
		Total	58,382,315	113,363,603	14,641,347,928

Customer Service Rankings [2013-2017] **Source: SNL**

Holding Company	CA O&M	CS&I O&M	Sales O&M	CS O&M	Total Sales of Elect. Volume (MWh)	CS O&M/MWh	Ranking
CenterPoint Energy, Inc.	162,439,000	197,953,000	0	360,392,000	421,479,989	0.86	1
NiSource Inc.	93,272,000	2,734,000	5,524,000	101,530,000	85,969,484	1.18	2
Westar Energy, Inc.	150,871,000	18,014,000	2,000	168,887,000	142,855,162	1.18	3
ALLETE, Inc.	33,300,000	54,395,000	869,000	88,564,000	74,330,795	1.19	4
MDU Resources Group, Inc.	21,613,000	1,270,000	677,000	23,560,000	16,493,138	1.43	5
Dominion Energy, Inc.	439,980,000	175,490,000	88,000	615,558,000	424,814,207	1.45	6
Black Hills Corporation	39,069,000	10,800,000	185,000	50,054,000	32,232,125	1.55	7
Duke Energy Corporation	1,267,387,000	734,174,000	111,519,000	2,113,080,000	1,280,342,802	1.65	8
Entergy Corporation	681,360,000	472,990,000	29,855,000	1,184,205,000	694,118,461	1.71	9
PNM Resources, Inc.	75,588,000	4,093,000	23,389,000	103,070,000	60,114,213	1.71	10
El Paso Electric Company	94,772,000	1,040,000	0	95,812,000	54,312,529	1.76	11
NextEra Energy, Inc.	564,942,000	500,604,000	24,482,000	1,090,028,000	576,861,659	1.89	12
NorthWestern Corporation	59,911,000	32,141,000	2,767,000	94,819,000	48,516,397	1.95	13
Sempra Energy	329,721,000	1,143,888,000	118,000	1,473,727,000	732,367,419	2.01	14
Cleco Partners LP	62,686,000	37,608,000	24,297,000	124,591,000	58,299,323	2.14	15
LKE	222,919,810	178,486,000	4,703,000	406,108,810	177,006,629	2.29	16
Caisse de dépôt et	39,645,000	14,653,000	253,000	54,551,000	23,640,213	2.31	17
OGE Energy Corp.	108,700,000	208,136,000	28,493,000	345,329,000	145,554,088	2.37	18
Algonquin Power & Utilities Corp.	59,128,000	16,283,000	1,550,000	76,961,000	29,685,318	2.59	19
SCANA Corporation	237,883,000	59,843,000	7,910,000	305,636,000	115,124,628	2.65	20
AEP	1,593,674,000	894,932,000	16,588,000	2,505,194,000	926,060,218	2.71	21
Southern Company	1,411,466,000	828,270,000	345,608,000	2,585,344,000	915,739,927	2.82	22
WEC Energy Group, Inc.	344,698,000	379,294,000	2,858,000	726,850,000	247,141,624	2.94	23
Vectren Corporation	30,806,000	2,703,000	53,341,000	86,850,000	28,861,057	3.01	24
Alliant Energy Corporation	170,260,000	306,565,000	0	476,825,000	158,149,961	3.02	25
Great Plains Energy Incorporated	160,502,000	302,006,000	3,646,000	466,154,000	149,872,607	3.11	26
Ameren Corporation	488,090,000	749,302,000	2,126,000	1,239,518,000	396,912,264	3.12	27
Portland General Electric Company	270,282,000	72,413,000	0	342,695,000	105,742,391	3.24	28
AES Corporation	358,451,000	159,247,000	0	517,698,000	157,380,054	3.29	29
FirstEnergy Corp.	1,085,378,000	1,566,723,000	11,122,000	2,663,223,000	795,797,359	3.35	30
Xcel Energy Inc.	592,390,000	1,215,984,000	4,203,000	1,812,577,000	541,441,613	3.35	31
Avista Corporation	83,892,000	129,760,000	7,000	213,659,000	63,822,212	3.35	32
Berkshire Hathaway Inc.	817,844,000	1,390,145,000	23,904,000	2,231,893,000	647,595,062	3.45	33
UGI Corporation	15,319,000	1,696,000	146,000	17,161,000	4,900,628	3.50	34

Customer Service Rankings [2013-2017] **Source: SNL**

Holding Company	CA O&M	CS&I O&M	Sales O&M	CS O&M	Total Sales of Elect. Volume (MWh)	CS O&M/MWh	Ranking
Emera Incorporated	192,682,000	218,461,000	4,034,000	415,177,000	106,439,317	3.90	35
Pinnacle West Capital Corporation	270,894,000	306,326,000	56,863,000	634,083,000	161,506,003	3.93	36
IDACORP, Inc.	111,820,000	208,459,000	80,000	320,359,000	80,222,328	3.99	37
Mt. Carmel Public Utility Company	1,997,000	37,000	26,000	2,060,000	490,041	4.20	38
MGE Energy, Inc.	33,486,000	41,101,000	1,139,000	75,726,000	17,944,098	4.22	39
Otter Tail Corporation	64,959,000	45,164,000	2,113,000	112,236,000	26,396,332	4.25	40
DQE Holdings LLC	130,876,000	168,045,000	0	298,921,000	67,127,889	4.45	41
PPL Corporation	391,953,000	473,262,000	10,344,000	875,559,000	188,245,085	4.65	42
Exelon Corporation	3,259,289,000	1,672,212,000	6,644,000	4,938,145,000	1,034,415,389	4.77	43
CMS Energy Corporation	375,388,000	522,325,000	1,093,000	898,806,000	180,393,075	4.98	44
DTE Energy Company	800,272,000	427,083,000	9,419,000	1,236,774,000	230,365,093	5.37	45
Fortis Inc.	206,686,000	320,902,000	685,000	528,273,000	90,696,008	5.82	46
Puget Holdings LLC	257,578,000	577,763,000	2,356,000	837,697,000	132,788,263	6.31	47
Balfour Beatty Infrastructure	18,276,000	13,179,000	0	31,455,000	4,147,629	7.58	48
Edison International	864,759,000	2,819,813,000	49,144,000	3,733,716,000	476,972,294	7.83	49
Unitil Corporation	33,817,000	34,545,000	3,826,000	72,188,000	8,513,641	8.48	50
PG&E Corporation	1,116,120,000	2,986,920,000	30,751,000	4,133,791,000	437,736,683	9.44	51
Public Service Enterprise Group Inc	1,354,998,000	884,543,000	6,595,000	2,246,136,000	213,547,903	10.52	52
Eversource Energy	1,040,861,000	2,187,690,000	7,268,000	3,235,819,000	289,678,343	11.17	53
Iberdrola, S.A.	819,054,000	889,669,000	66,892,000	1,775,615,000	157,875,239	11.25	54
Consolidated Edison, Inc.	1,204,293,000	2,029,448,000	9,736,000	3,243,477,000	264,071,298	12.28	55
National Grid plc	882,152,000	2,400,556,000	21,747,000	3,304,455,000	160,448,295	20.60	56
Grand Total	25,600,448,810	31,091,138,000	1,020,985,000	57,712,571,810	14,663,555,802		

CA = Customer Account Expense

CS&I = Customer Service and Informational Expense

Q1	2.11
Q2	3.27
Q3	4.68
Industry Avg.	3.94

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Dayton Power and Light Company	AES Corporation	72,695	19,421	0	19,416,290
2014Y	Dayton Power and Light Company	AES Corporation	64,226	22,864	0	18,643,195
2015Y	Dayton Power and Light Company	AES Corporation	44,135	28,756	0	16,433,036
2016Y	Dayton Power and Light Company	AES Corporation	50,237	42,788	0	16,158,129
2017Y	Dayton Power and Light Company	AES Corporation	21,638	36,072	0	12,236,126
2013Y	Indianapolis Power & Light Company	AES Corporation	20,099	2,227	0	16,033,922
2014Y	Indianapolis Power & Light Company	AES Corporation	21,399	1,963	0	16,391,321
2015Y	Indianapolis Power & Light Company	AES Corporation	21,360	1,590	0	14,397,561
2016Y	Indianapolis Power & Light Company	AES Corporation	20,773	1,661	0	14,185,985
2017Y	Indianapolis Power & Light Company	AES Corporation	21,889	1,905	0	13,484,489
2013Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	10,067	2,209	349	5,620,276
2014Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	9,770	2,910	180	5,131,750
2015Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	8,624	2,986	195	4,940,028
2016Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	8,062	3,371	154	4,950,707
2017Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	8,354	4,036	158	4,841,355
2013Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	2,599	176	57	552,273
2014Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	3,435	170	172	910,825
2015Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	3,660	206	49	933,262
2016Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	2,368	169	83	910,242
2017Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	2,189	50	153	894,600
2013Y	ALLETE (Minnesota Power)	ALLETE, Inc.	5,824	13,459	217	13,264,062
2014Y	ALLETE (Minnesota Power)	ALLETE, Inc.	5,600	11,771	143	13,942,499
2015Y	ALLETE (Minnesota Power)	ALLETE, Inc.	5,473	8,402	127	14,369,559
2016Y	ALLETE (Minnesota Power)	ALLETE, Inc.	5,802	4,018	163	14,147,335
2017Y	ALLETE (Minnesota Power)	ALLETE, Inc.	6,572	11,667	219	14,692,658
2013Y	Superior Water, Light and Power Company	ALLETE, Inc.	698	1,049	0	687,209
2014Y	Superior Water, Light and Power Company	ALLETE, Inc.	845	1,052	0	770,427
2015Y	Superior Water, Light and Power Company	ALLETE, Inc.	815	1,042	0	788,342
2016Y	Superior Water, Light and Power Company	ALLETE, Inc.	829	1,016	0	820,880
2017Y	Superior Water, Light and Power Company	ALLETE, Inc.	842	919	0	847,824
2013Y	Interstate Power and Light Company	Alliant Energy Corporation	21,688	39,823	0	17,194,056
2014Y	Interstate Power and Light Company	Alliant Energy Corporation	22,665	42,555	0	16,871,181
2015Y	Interstate Power and Light Company	Alliant Energy Corporation	19,872	46,725	0	16,703,172
2016Y	Interstate Power and Light Company	Alliant Energy Corporation	25,303	47,294	0	16,662,731

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Interstate Power and Light Company	Alliant Energy Corporation	25,805	41,492	0	17,406,995
2013Y	Wisconsin Power and Light Company	Alliant Energy Corporation	9,135	21,643	0	14,862,652
2014Y	Wisconsin Power and Light Company	Alliant Energy Corporation	10,442	43,600	0	14,603,712
2015Y	Wisconsin Power and Light Company	Alliant Energy Corporation	10,818	9,005	0	15,199,013
2016Y	Wisconsin Power and Light Company	Alliant Energy Corporation	10,275	-6,451	0	14,480,783
2017Y	Wisconsin Power and Light Company	Alliant Energy Corporation	14,257	20,879	0	14,165,666
2013Y	Ameren Illinois Company	Ameren Corporation	50,285	61,910	2	38,012,834
2014Y	Ameren Illinois Company	Ameren Corporation	49,945	87,566	2	37,915,282
2015Y	Ameren Illinois Company	Ameren Corporation	54,084	84,795	2	36,850,871
2016Y	Ameren Illinois Company	Ameren Corporation	55,984	89,742	0	36,754,294
2017Y	Ameren Illinois Company	Ameren Corporation	52,232	42,798	0	35,537,431
2013Y	Union Electric Company	Ameren Corporation	38,686	57,800	447	43,158,138
2014Y	Union Electric Company	Ameren Corporation	39,791	66,225	463	43,192,724
2015Y	Union Electric Company	Ameren Corporation	50,894	97,842	458	43,255,846
2016Y	Union Electric Company	Ameren Corporation	49,258	72,182	364	39,997,209
2017Y	Union Electric Company	Ameren Corporation	46,931	88,442	388	42,237,635
2013Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2014Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA	47,215,732
2015Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2016Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2017Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2013Y	AEP Texas Central Company	American Electric Power Company, Inc.	11,717	15,471	139	NA
2014Y	AEP Texas Central Company	American Electric Power Company, Inc.	9,440	15,026	261	NA
2015Y	AEP Texas Central Company	American Electric Power Company, Inc.	10,081	16,602	225	NA
2016Y	AEP Texas Central Company	American Electric Power Company, Inc.	7,701	15,645	189	NA
2017Y	AEP Texas Central Company	American Electric Power Company, Inc.	NA	NA	NA	NA
2013Y	AEP Texas North Company	American Electric Power Company, Inc.	2,881	3,542	31	2,435,181
2014Y	AEP Texas North Company	American Electric Power Company, Inc.	2,358	3,077	59	1,741,758
2015Y	AEP Texas North Company	American Electric Power Company, Inc.	2,519	3,295	51	1,368,742
2016Y	AEP Texas North Company	American Electric Power Company, Inc.	1,908	2,846	43	1,381,295
2017Y	AEP Texas North Company	American Electric Power Company, Inc.	NA	NA	NA	NA
2013Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2014Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2015Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA	NA	NA
2017Y	AEP Texas, Inc.	American Electric Power Company, Inc.	11,154	17,611	298	923,791
2013Y	Appalachian Power Company	American Electric Power Company, Inc.	35,569	6,965	155	47,596,529
2014Y	Appalachian Power Company	American Electric Power Company, Inc.	40,890	8,717	297	35,769,358
2015Y	Appalachian Power Company	American Electric Power Company, Inc.	37,672	11,144	264	34,847,578
2016Y	Appalachian Power Company	American Electric Power Company, Inc.	37,801	16,466	213	34,862,820
2017Y	Appalachian Power Company	American Electric Power Company, Inc.	39,807	17,920	275	33,601,395
2013Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	15,722	31,205	99	38,036,953
2014Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	16,054	14,317	212	35,331,017
2015Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	15,383	19,819	314	30,404,900
2016Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	15,399	21,929	66	28,379,413
2017Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	15,024	25,384	211	29,819,953
2013Y	Kentucky Power Company	American Electric Power Company, Inc.	5,734	3,691	31	9,933,527
2014Y	Kentucky Power Company	American Electric Power Company, Inc.	6,201	4,938	54	11,993,933
2015Y	Kentucky Power Company	American Electric Power Company, Inc.	6,131	3,909	47	8,700,986
2016Y	Kentucky Power Company	American Electric Power Company, Inc.	5,707	6,544	94	7,276,047
2017Y	Kentucky Power Company	American Electric Power Company, Inc.	5,920	14,530	53	7,106,360
2013Y	Kingsport Power Company	American Electric Power Company, Inc.	1,497	53	7	2,045,738
2014Y	Kingsport Power Company	American Electric Power Company, Inc.	1,492	57	15	2,120,716
2015Y	Kingsport Power Company	American Electric Power Company, Inc.	1,446	112	12	2,086,994
2016Y	Kingsport Power Company	American Electric Power Company, Inc.	1,488	109	10	2,038,552
2017Y	Kingsport Power Company	American Electric Power Company, Inc.	1,564	372	14	1,971,080
2013Y	Ohio Power Company	American Electric Power Company, Inc.	235,451	91,566	1,913	60,639,578
2014Y	Ohio Power Company	American Electric Power Company, Inc.	239,732	80,889	2,236	15,591,760
2015Y	Ohio Power Company	American Electric Power Company, Inc.	229,629	63,565	2,138	45,685,751
2016Y	Ohio Power Company	American Electric Power Company, Inc.	249,681	63,769	2,532	45,870,876
2017Y	Ohio Power Company	American Electric Power Company, Inc.	71,152	52,814	2,531	45,688,514
2013Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	18,603	21,640	115	19,239,394
2014Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	19,586	30,573	204	19,517,893
2015Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	19,118	30,579	159	18,916,965
2016Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	15,640	32,808	139	19,425,199
2017Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	14,920	35,115	171	19,052,676
2013Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	21,582	15,772	85	28,553,233
2014Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	22,604	15,240	163	28,644,882

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	21,413	19,057	140	27,269,400
2016Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	20,475	17,268	118	26,169,526
2017Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	19,948	15,362	153	26,257,034
2013Y	Wheeling Power Company	American Electric Power Company, Inc.	1,301	861	7	2,703,781
2014Y	Wheeling Power Company	American Electric Power Company, Inc.	1,849	1,514	13	3,269,892
2015Y	Wheeling Power Company	American Electric Power Company, Inc.	1,678	1,816	11	4,451,364
2016Y	Wheeling Power Company	American Electric Power Company, Inc.	1,412	1,759	9	5,106,836
2017Y	Wheeling Power Company	American Electric Power Company, Inc.	1,640	1,669	12	5,015,316
2013Y	Alaska Electric Light and Power Company	Avista Corporation	1,160	5	0	377,005
2014Y	Alaska Electric Light and Power Company	Avista Corporation	1,168	2	0	422,784
2015Y	Alaska Electric Light and Power Company	Avista Corporation	1,114	4	0	398,066
2016Y	Alaska Electric Light and Power Company	Avista Corporation	1,109	4	0	395,154
2017Y	Alaska Electric Light and Power Company	Avista Corporation	1,182	19	0	414,210
2013Y	Avista Corporation	Avista Corporation	15,187	21,884	7	13,318,994
2014Y	Avista Corporation	Avista Corporation	14,540	26,943	0	12,839,533
2015Y	Avista Corporation	Avista Corporation	15,539	25,612	0	11,942,035
2016Y	Avista Corporation	Avista Corporation	16,702	24,905	0	11,733,626
2017Y	Avista Corporation	Avista Corporation	16,191	30,382	0	11,980,805
2013Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	3,284	2,493	0	881,022
2014Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	3,422	2,556	0	845,665
2015Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	3,507	2,661	0	844,127
2016Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	3,296	2,718	0	831,622
2017Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	4,767	2,751	0	745,193
2013Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	26,766	56,919	4,769	32,680,735
2014Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	28,091	78,013	4,617	32,499,927
2015Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	27,460	80,221	3,602	31,832,657
2016Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	27,496	85,276	3,658	32,475,023
2017Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	27,940	107,483	3,769	33,727,302
2013Y	Nevada Power Company	Berkshire Hathaway Inc.	42,720	68,921	218	24,064,426
2014Y	Nevada Power Company	Berkshire Hathaway Inc.	40,032	53,978	135	22,745,488
2015Y	Nevada Power Company	Berkshire Hathaway Inc.	39,787	62,223	147	25,481,621
2016Y	Nevada Power Company	Berkshire Hathaway Inc.	40,887	62,873	193	25,062,084
2017Y	Nevada Power Company	Berkshire Hathaway Inc.	41,320	42,560	215	23,751,206
2013Y	PacifiCorp	Berkshire Hathaway Inc.	87,534	116,605	0	65,869,008

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2014Y	PacifiCorp	Berkshire Hathaway Inc.	85,292	136,012	0	65,269,524
2015Y	PacifiCorp	Berkshire Hathaway Inc.	81,366	135,712	0	63,530,663
2016Y	PacifiCorp	Berkshire Hathaway Inc.	83,187	147,415	0	60,958,902
2017Y	PacifiCorp	Berkshire Hathaway Inc.	86,106	91,522	0	62,468,319
2013Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	13,429	18,622	562	9,185,572
2014Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	10,592	6,712	547	8,882,408
2015Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	9,477	11,264	466	8,911,051
2016Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	9,315	14,571	523	9,000,293
2017Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	9,047	13,243	483	9,198,853
2013Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,296	431	29	2,028,643
2014Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	4,056	121	29	1,957,695
2015Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,975	60	15	1,959,505
2016Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,668	65	7	1,985,177
2017Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	3,868	51	8	1,932,972
2013Y	Black Hills Power, Inc.	Black Hills Corporation	2,850	1,338	39	3,084,298
2014Y	Black Hills Power, Inc.	Black Hills Corporation	3,251	1,536	25	2,905,098
2015Y	Black Hills Power, Inc.	Black Hills Corporation	3,239	1,717	4	2,873,371
2016Y	Black Hills Power, Inc.	Black Hills Corporation	3,037	1,498	2	2,611,946
2017Y	Black Hills Power, Inc.	Black Hills Corporation	3,005	1,010	3	2,992,386
2013Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	1,098	773	8	1,635,140
2014Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	1,082	812	6	1,639,680
2015Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	961	644	3	1,418,697
2016Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	885	457	5	1,559,870
2017Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	798	287	2	1,647,647
2013Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	8,549	3,771	3	4,853,495
2014Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	8,949	3,375	23	4,713,347
2015Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	9,145	2,572	28	4,751,076
2016Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	7,523	2,452	122	4,688,744
2017Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	5,479	2,483	77	4,633,551
2013Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	30,163	40,320	0	79,984,965
2014Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	30,132	40,888	0	81,839,060
2015Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	35,480	42,889	0	84,190,647
2016Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	34,309	38,303	0	86,828,900
2017Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	32,355	35,553	0	88,636,417

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2013Y	Cleco Power LLC	Cleco Partners LP	11,227	5,919	4,529	11,115,732
2014Y	Cleco Power LLC	Cleco Partners LP	10,857	5,911	4,834	12,201,940
2015Y	Cleco Power LLC	Cleco Partners LP	12,231	9,111	5,911	12,105,640
2016Y	Cleco Power LLC	Cleco Partners LP	15,195	8,265	4,870	11,596,427
2017Y	Cleco Power LLC	Cleco Partners LP	13,176	8,402	4,153	11,279,584
2013Y	Consumers Energy Company	CMS Energy Corporation	82,676	82,970	72	35,276,791
2014Y	Consumers Energy Company	CMS Energy Corporation	84,296	105,188	279	35,893,242
2015Y	Consumers Energy Company	CMS Energy Corporation	78,263	103,218	199	36,357,438
2016Y	Consumers Energy Company	CMS Energy Corporation	69,143	107,131	165	36,746,531
2017Y	Consumers Energy Company	CMS Energy Corporation	61,010	123,818	378	36,119,073
2013Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	227,454	288,861	9,641	47,335,320
2014Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	235,949	341,180	0	46,406,542
2015Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	216,744	380,851	0	47,202,850
2016Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	200,873	387,254	0	47,450,242
2017Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	211,764	416,725	0	46,342,045
2013Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	14,564	27,905	9	4,263,699
2014Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	18,444	32,499	13	4,256,408
2015Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	17,271	35,243	26	4,415,840
2016Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	18,010	32,295	19	4,315,576
2017Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	18,248	34,674	15	4,056,841
2013Y	Rockland Electric Company	Consolidated Edison, Inc.	4,967	10,556	2	1,642,857
2014Y	Rockland Electric Company	Consolidated Edison, Inc.	4,421	11,831	2	1,610,904
2015Y	Rockland Electric Company	Consolidated Edison, Inc.	4,839	8,954	6	1,631,351
2016Y	Rockland Electric Company	Consolidated Edison, Inc.	5,290	10,002	2	1,601,861
2017Y	Rockland Electric Company	Consolidated Edison, Inc.	5,455	10,618	1	1,538,962
2013Y	Virginia Electric and Power Company	Dominion Energy, Inc.	84,749	24,653	0	82,852,117
2014Y	Virginia Electric and Power Company	Dominion Energy, Inc.	103,838	32,437	0	83,938,195
2015Y	Virginia Electric and Power Company	Dominion Energy, Inc.	89,770	37,651	0	85,178,907
2016Y	Virginia Electric and Power Company	Dominion Energy, Inc.	80,534	43,352	0	87,875,099
2017Y	Virginia Electric and Power Company	Dominion Energy, Inc.	81,089	37,397	88	84,969,889
2013Y	Duquesne Light Company	DQE Holdings LLC	20,307	29,038	0	14,007,273
2014Y	Duquesne Light Company	DQE Holdings LLC	24,116	25,729	0	13,747,339
2015Y	Duquesne Light Company	DQE Holdings LLC	31,620	41,642	0	13,503,863
2016Y	Duquesne Light Company	DQE Holdings LLC	28,334	34,761	0	13,172,591

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2017Y	Duquesne Light Company	DQE Holdings LLC	26,499	36,875	0	12,696,823
2013Y	DTE Electric Company	DTE Energy Company	157,975	69,017	1,801	47,062,371
2014Y	DTE Electric Company	DTE Energy Company	157,639	87,951	1,038	46,076,577
2015Y	DTE Electric Company	DTE Energy Company	162,184	88,340	382	46,281,765
2016Y	DTE Electric Company	DTE Energy Company	152,087	91,192	1,456	45,998,164
2017Y	DTE Electric Company	DTE Energy Company	170,387	90,583	4,742	44,946,216
2013Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	79,219	28,943	1,427	85,789,697
2014Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	78,523	21,845	7,325	87,645,520
2015Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	81,499	19,266	9,243	87,375,571
2016Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	83,506	20,610	10,355	88,544,715
2017Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	84,236	20,720	11,583	87,306,564
2013Y	Duke Energy Florida, LLC	Duke Energy Corporation	46,992	94,825	1,937	38,164,155
2014Y	Duke Energy Florida, LLC	Duke Energy Corporation	57,525	115,469	2,331	38,728,049
2015Y	Duke Energy Florida, LLC	Duke Energy Corporation	57,771	83,883	3,657	39,989,379
2016Y	Duke Energy Florida, LLC	Duke Energy Corporation	59,606	101,995	4,499	40,660,935
2017Y	Duke Energy Florida, LLC	Duke Energy Corporation	57,717	97,908	7,284	40,290,293
2013Y	Duke Energy Indiana, LLC	Duke Energy Corporation	39,353	11,036	270	33,714,982
2014Y	Duke Energy Indiana, LLC	Duke Energy Corporation	40,233	6,905	2,209	33,433,620
2015Y	Duke Energy Indiana, LLC	Duke Energy Corporation	41,014	5,651	2,884	33,517,569
2016Y	Duke Energy Indiana, LLC	Duke Energy Corporation	27,491	5,087	3,560	34,368,826
2017Y	Duke Energy Indiana, LLC	Duke Energy Corporation	29,240	4,662	4,236	33,145,670
2013Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	6,495	1,506	51	4,546,692
2014Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	6,645	975	553	4,447,988
2015Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	6,599	563	909	5,277,786
2016Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	6,218	673	905	4,672,987
2017Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	5,442	593	889	4,908,072
2013Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	30,150	7,122	318	39,309,749
2014Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	26,830	4,769	1,700	27,741,596
2015Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	29,239	3,640	2,953	20,805,363
2016Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	23,016	3,710	3,042	21,320,518
2017Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	21,576	3,481	3,289	20,805,946
2013Y	Duke Energy Progress, LLC	Duke Energy Corporation	44,157	51,420	1,800	60,204,063
2014Y	Duke Energy Progress, LLC	Duke Energy Corporation	49,288	4,646	4,171	62,871,047
2015Y	Duke Energy Progress, LLC	Duke Energy Corporation	52,930	3,708	5,624	64,880,560

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2016Y	Duke Energy Progress, LLC	Duke Energy Corporation	47,900	4,480	6,307	69,052,154
2017Y	Duke Energy Progress, LLC	Duke Energy Corporation	46,977	4,083	6,208	66,822,736
2013Y	Southern California Edison Company	Edison International	191,060	598,329	14,170	90,552,978
2014Y	Southern California Edison Company	Edison International	177,028	629,097	11,300	116,437,195
2015Y	Southern California Edison Company	Edison International	179,164	569,076	6,873	90,495,397
2016Y	Southern California Edison Company	Edison International	165,721	506,648	8,294	88,194,998
2017Y	Southern California Edison Company	Edison International	151,786	516,663	8,507	91,291,726
2013Y	El Paso Electric Company	El Paso Electric Company	17,602	200	0	10,884,241
2014Y	El Paso Electric Company	El Paso Electric Company	19,737	208	0	11,009,422
2015Y	El Paso Electric Company	El Paso Electric Company	19,148	222	0	10,915,601
2016Y	El Paso Electric Company	El Paso Electric Company	18,853	205	0	10,598,511
2017Y	El Paso Electric Company	El Paso Electric Company	19,432	205	0	10,904,754
2013Y	Emera Maine	Emera Incorporated	5,984	177	0	1,869,923
2014Y	Emera Maine	Emera Incorporated	8,220	279	0	2,344,241
2015Y	Emera Maine	Emera Incorporated	7,916	223	0	2,325,046
2016Y	Emera Maine	Emera Incorporated	8,929	186	0	2,217,874
2017Y	Emera Maine	Emera Incorporated	9,787	83	0	2,270,073
2013Y	Tampa Electric Company	Emera Incorporated	23,344	47,774	1,431	18,639,927
2014Y	Tampa Electric Company	Emera Incorporated	29,204	46,848	560	18,784,911
2015Y	Tampa Electric Company	Emera Incorporated	26,215	46,989	803	19,121,762
2016Y	Tampa Electric Company	Emera Incorporated	34,013	37,694	689	19,440,142
2017Y	Tampa Electric Company	Emera Incorporated	39,070	38,208	551	19,425,418
2013Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA
2014Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA
2015Y	EL Investment Company, LLC	Entergy Corporation	24,090	6,034	1,295	31,482,380
2016Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA
2017Y	EL Investment Company, LLC	Entergy Corporation	NA	NA	NA	NA
2013Y	Entergy Arkansas, Inc.	Entergy Corporation	38,461	41,853	595	29,788,956
2014Y	Entergy Arkansas, Inc.	Entergy Corporation	36,880	68,221	774	31,350,781
2015Y	Entergy Arkansas, Inc.	Entergy Corporation	35,843	74,662	737	31,379,457
2016Y	Entergy Arkansas, Inc.	Entergy Corporation	34,220	66,675	611	29,363,790
2017Y	Entergy Arkansas, Inc.	Entergy Corporation	36,215	53,392	357	29,219,532
2013Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	17,739	2,468	2,409	27,130,595
2014Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	18,917	3,075	1,851	28,713,874

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	12,662	3,683	1,218	21,426,698
2016Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA	NA
2017Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA	NA	NA
2013Y	Entergy Louisiana, LLC	Entergy Corporation	31,816	3,353	2,147	34,156,904
2014Y	Entergy Louisiana, LLC	Entergy Corporation	34,157	4,986	2,047	37,479,888
2015Y	Entergy Louisiana, LLC	Entergy Corporation	11,956	2,770	1,302	14,743,976
2016Y	Entergy Louisiana, LLC	Entergy Corporation	46,151	12,876	3,396	63,634,403
2017Y	Entergy Louisiana, LLC	Entergy Corporation	51,910	14,704	3,406	61,747,129
2013Y	Entergy Mississippi, Inc.	Entergy Corporation	24,263	4,036	422	14,965,739
2014Y	Entergy Mississippi, Inc.	Entergy Corporation	24,275	4,873	1,339	16,054,977
2015Y	Entergy Mississippi, Inc.	Entergy Corporation	23,580	8,835	944	14,969,217
2016Y	Entergy Mississippi, Inc.	Entergy Corporation	21,021	6,801	587	14,462,253
2017Y	Entergy Mississippi, Inc.	Entergy Corporation	21,572	11,730	862	13,904,918
2013Y	Entergy New Orleans, LLC	Entergy Corporation	9,508	1,938	530	5,615,573
2014Y	Entergy New Orleans, LLC	Entergy Corporation	8,432	1,229	489	6,570,789
2015Y	Entergy New Orleans, LLC	Entergy Corporation	8,252	5,303	519	7,138,626
2016Y	Entergy New Orleans, LLC	Entergy Corporation	11,180	6,855	293	6,947,771
2017Y	Entergy New Orleans, LLC	Entergy Corporation	9,829	8,384	206	7,327,377
2013Y	Entergy Texas, Inc.	Entergy Corporation	17,710	12,601	337	23,811,698
2014Y	Entergy Texas, Inc.	Entergy Corporation	18,046	8,046	418	22,661,605
2015Y	Entergy Texas, Inc.	Entergy Corporation	17,159	13,672	364	23,855,503
2016Y	Entergy Texas, Inc.	Entergy Corporation	16,632	9,509	227	23,892,632
2017Y	Entergy Texas, Inc.	Entergy Corporation	18,884	10,426	173	20,321,420
2013Y	Connecticut Light and Power Company	Eversource Energy	96,010	109,185	115	23,299,945
2014Y	Connecticut Light and Power Company	Eversource Energy	111,840	176,925	154	22,647,162
2015Y	Connecticut Light and Power Company	Eversource Energy	99,752	174,601	62	22,643,456
2016Y	Connecticut Light and Power Company	Eversource Energy	105,644	171,144	-29	22,342,433
2017Y	Connecticut Light and Power Company	Eversource Energy	92,420	141,430	0	21,611,697
2013Y	NSTAR Electric Company	Eversource Energy	59,449	200,433	3,102	23,996,935
2014Y	NSTAR Electric Company	Eversource Energy	51,405	184,100	2,241	23,629,876
2015Y	NSTAR Electric Company	Eversource Energy	29,900	199,400	1,216	23,856,657
2016Y	NSTAR Electric Company	Eversource Energy	77,547	268,159	190	23,127,763
2017Y	NSTAR Electric Company	Eversource Energy	76,121	263,228	56	21,529,739
2013Y	Public Service Company of New Hampshire	Eversource Energy	29,001	18,751	42	9,118,546

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Public Service Company of New Hampshire	Eversource Energy	32,405	17,562	61	8,595,895
2015Y	Public Service Company of New Hampshire	Eversource Energy	34,226	16,026	24	8,441,532
2016Y	Public Service Company of New Hampshire	Eversource Energy	29,651	16,146	-10	8,388,691
2017Y	Public Service Company of New Hampshire	Eversource Energy	28,814	16,301	0	8,116,389
2013Y	Western Massachusetts Electric Company	Eversource Energy	16,437	39,424	17	3,724,299
2014Y	Western Massachusetts Electric Company	Eversource Energy	13,151	42,706	22	3,610,361
2015Y	Western Massachusetts Electric Company	Eversource Energy	18,279	41,901	10	3,601,321
2016Y	Western Massachusetts Electric Company	Eversource Energy	18,677	46,876	-5	3,706,255
2017Y	Western Massachusetts Electric Company	Eversource Energy	20,132	43,392	0	3,689,391
2013Y	Atlantic City Electric Company	Exelon Corporation	55,157	36,230	0	11,562,281
2014Y	Atlantic City Electric Company	Exelon Corporation	60,224	34,973	0	11,658,993
2015Y	Atlantic City Electric Company	Exelon Corporation	80,958	35,384	4	11,225,247
2016Y	Atlantic City Electric Company	Exelon Corporation	89,038	37,025	0	10,723,259
2017Y	Atlantic City Electric Company	Exelon Corporation	64,348	36,619	0	9,822,917
2013Y	Baltimore Gas and Electric Company	Exelon Corporation	76,518	4,355	0	30,767,778
2014Y	Baltimore Gas and Electric Company	Exelon Corporation	86,771	5,142	0	30,562,078
2015Y	Baltimore Gas and Electric Company	Exelon Corporation	56,076	4,942	0	30,304,293
2016Y	Baltimore Gas and Electric Company	Exelon Corporation	38,239	4,316	0	30,019,586
2017Y	Baltimore Gas and Electric Company	Exelon Corporation	53,272	4,154	0	28,970,770
2013Y	Commonwealth Edison Company	Exelon Corporation	229,749	187,943	0	93,089,440
2014Y	Commonwealth Edison Company	Exelon Corporation	252,022	244,512	0	90,578,581
2015Y	Commonwealth Edison Company	Exelon Corporation	248,386	250,479	0	87,297,520
2016Y	Commonwealth Edison Company	Exelon Corporation	243,296	226,858	0	89,608,490
2017Y	Commonwealth Edison Company	Exelon Corporation	229,443	132,730	0	87,568,519
2013Y	Delmarva Power & Light Company	Exelon Corporation	53,329	3,159	428	12,817,180
2014Y	Delmarva Power & Light Company	Exelon Corporation	57,688	4,688	390	12,782,957
2015Y	Delmarva Power & Light Company	Exelon Corporation	74,278	5,202	590	12,805,844
2016Y	Delmarva Power & Light Company	Exelon Corporation	73,878	4,988	596	12,486,406
2017Y	Delmarva Power & Light Company	Exelon Corporation	54,619	7,941	606	12,222,536
2013Y	PECO Energy Company	Exelon Corporation	153,767	60,870	899	38,044,130
2014Y	PECO Energy Company	Exelon Corporation	135,516	77,724	1,006	37,681,485
2015Y	PECO Energy Company	Exelon Corporation	104,607	86,565	766	38,124,845
2016Y	PECO Energy Company	Exelon Corporation	102,080	79,400	616	37,940,620
2017Y	PECO Energy Company	Exelon Corporation	98,209	68,108	737	37,233,657

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Potomac Electric Power Company	Exelon Corporation	82,763	1,990	3	25,807,813
2014Y	Potomac Electric Power Company	Exelon Corporation	90,071	3,774	0	25,750,549
2015Y	Potomac Electric Power Company	Exelon Corporation	115,437	4,140	135	25,987,432
2016Y	Potomac Electric Power Company	Exelon Corporation	110,158	8,685	-132	26,114,290
2017Y	Potomac Electric Power Company	Exelon Corporation	89,392	9,316	0	24,855,893
2013Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	18,809	17,273	331	18,712,244
2014Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	18,862	16,051	422	18,733,302
2015Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	24,034	13,144	475	18,501,986
2016Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	24,518	7,415	577	18,817,928
2017Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	24,926	16,833	887	18,290,574
2013Y	Jersey Central Power & Light Company	FirstEnergy Corp.	36,629	132,126	0	21,836,806
2014Y	Jersey Central Power & Light Company	FirstEnergy Corp.	33,640	134,475	0	21,846,258
2015Y	Jersey Central Power & Light Company	FirstEnergy Corp.	37,931	142,013	25	21,332,986
2016Y	Jersey Central Power & Light Company	FirstEnergy Corp.	36,853	141,494	103	21,250,880
2017Y	Jersey Central Power & Light Company	FirstEnergy Corp.	35,110	129,628	301	20,535,764
2013Y	Metropolitan Edison Company	FirstEnergy Corp.	24,965	41,900	14	14,226,643
2014Y	Metropolitan Edison Company	FirstEnergy Corp.	25,745	35,919	29	14,276,774
2015Y	Metropolitan Edison Company	FirstEnergy Corp.	30,405	34,512	39	14,291,940
2016Y	Metropolitan Edison Company	FirstEnergy Corp.	27,391	33,168	74	14,143,059
2017Y	Metropolitan Edison Company	FirstEnergy Corp.	25,130	33,997	123	13,777,426
2013Y	Monongahela Power Company	FirstEnergy Corp.	15,100	3,520	0	10,816,852
2014Y	Monongahela Power Company	FirstEnergy Corp.	15,506	3,599	0	17,361,198
2015Y	Monongahela Power Company	FirstEnergy Corp.	21,219	3,889	13	16,163,874
2016Y	Monongahela Power Company	FirstEnergy Corp.	16,539	3,689	47	17,434,322
2017Y	Monongahela Power Company	FirstEnergy Corp.	18,017	5,040	97	17,497,075
2013Y	Ohio Edison Company	FirstEnergy Corp.	26,166	24,190	1,046	27,059,942
2014Y	Ohio Edison Company	FirstEnergy Corp.	27,397	21,686	1,025	27,819,394
2015Y	Ohio Edison Company	FirstEnergy Corp.	33,195	16,238	1,192	27,056,153
2016Y	Ohio Edison Company	FirstEnergy Corp.	34,184	9,420	1,304	26,451,421
2017Y	Ohio Edison Company	FirstEnergy Corp.	33,895	22,383	2,027	23,977,058
2013Y	Pennsylvania Electric Company	FirstEnergy Corp.	22,777	44,947	14	15,484,578
2014Y	Pennsylvania Electric Company	FirstEnergy Corp.	22,106	37,630	31	14,771,582
2015Y	Pennsylvania Electric Company	FirstEnergy Corp.	28,658	35,996	41	14,473,442
2016Y	Pennsylvania Electric Company	FirstEnergy Corp.	27,031	36,753	81	14,386,263

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Pennsylvania Electric Company	FirstEnergy Corp.	23,792	37,889	138	14,363,454
2013Y	Pennsylvania Power Company	FirstEnergy Corp.	4,882	12,042	4	4,567,609
2014Y	Pennsylvania Power Company	FirstEnergy Corp.	4,833	10,693	9	4,714,488
2015Y	Pennsylvania Power Company	FirstEnergy Corp.	6,639	9,557	11	4,526,159
2016Y	Pennsylvania Power Company	FirstEnergy Corp.	6,134	10,294	20	4,615,081
2017Y	Pennsylvania Power Company	FirstEnergy Corp.	5,589	10,829	35	4,633,922
2013Y	Potomac Edison Company	FirstEnergy Corp.	13,425	14,287	0	11,862,840
2014Y	Potomac Edison Company	FirstEnergy Corp.	12,364	23,321	0	11,898,341
2015Y	Potomac Edison Company	FirstEnergy Corp.	13,703	15,701	12	11,823,082
2016Y	Potomac Edison Company	FirstEnergy Corp.	13,916	19,682	37	11,554,451
2017Y	Potomac Edison Company	FirstEnergy Corp.	12,009	14,060	90	11,322,812
2013Y	Toledo Edison Company	FirstEnergy Corp.	10,589	8,034	4	11,956,365
2014Y	Toledo Edison Company	FirstEnergy Corp.	10,133	8,320	11	11,873,197
2015Y	Toledo Edison Company	FirstEnergy Corp.	13,327	8,317	23	11,779,382
2016Y	Toledo Edison Company	FirstEnergy Corp.	12,991	3,225	48	12,079,562
2017Y	Toledo Edison Company	FirstEnergy Corp.	12,753	7,782	132	10,856,745
2013Y	West Penn Power Company	FirstEnergy Corp.	27,287	21,121	0	20,052,177
2014Y	West Penn Power Company	FirstEnergy Corp.	33,517	15,590	0	20,291,236
2015Y	West Penn Power Company	FirstEnergy Corp.	27,631	29,180	11	20,083,013
2016Y	West Penn Power Company	FirstEnergy Corp.	26,887	41,209	81	19,998,876
2017Y	West Penn Power Company	FirstEnergy Corp.	26,239	46,662	138	19,616,843
2013Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	16,190	38,802	336	2,761,676
2014Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	19,691	43,955	270	2,623,309
2015Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	20,136	48,387	54	2,608,207
2016Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	17,538	42,612	11	2,684,357
2017Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	18,023	45,718	14	2,602,989
2013Y	Tucson Electric Power Company	Fortis Inc.	18,213	15,663	0	13,025,375
2014Y	Tucson Electric Power Company	Fortis Inc.	17,568	13,048	0	13,311,011
2015Y	Tucson Electric Power Company	Fortis Inc.	17,871	15,282	0	14,279,396
2016Y	Tucson Electric Power Company	Fortis Inc.	19,668	20,645	0	13,718,397
2017Y	Tucson Electric Power Company	Fortis Inc.	20,583	16,212	0	13,442,595
2013Y	UNS Electric, Inc.	Fortis Inc.	4,338	4,222	0	2,230,041
2014Y	UNS Electric, Inc.	Fortis Inc.	4,717	3,734	0	1,982,714
2015Y	UNS Electric, Inc.	Fortis Inc.	3,978	3,990	0	1,746,289

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2016Y	UNS Electric, Inc.	Fortis Inc.	4,069	4,625	0	1,762,853
2017Y	UNS Electric, Inc.	Fortis Inc.	4,103	4,007	0	1,916,799
2013Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	19,211	13,659	423	21,683,329
2014Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	19,055	17,553	403	22,472,307
2015Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	20,274	32,898	470	20,796,733
2016Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	19,997	49,104	487	21,433,876
2017Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	20,531	43,008	574	21,322,723
2013Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	12,307	14,906	224	8,413,828
2014Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	12,119	21,176	219	8,511,766
2015Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	12,314	36,440	263	8,385,574
2016Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	12,344	31,427	274	8,465,650
2017Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	12,350	41,835	309	8,386,821
2013Y	Central Maine Power Company	Iberdrola, S.A.	29,123	1,311	2,482	603,824
2014Y	Central Maine Power Company	Iberdrola, S.A.	30,924	1,235	2,849	590,204
2015Y	Central Maine Power Company	Iberdrola, S.A.	31,815	8,550	3,279	600,705
2016Y	Central Maine Power Company	Iberdrola, S.A.	33,020	22,962	1,943	599,743
2017Y	Central Maine Power Company	Iberdrola, S.A.	32,435	24,010	1,626	172,595
2013Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	60,942	76,423	5,734	19,115,201
2014Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	61,737	86,451	7,143	18,690,994
2015Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	71,348	95,109	7,165	17,887,199
2016Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	57,894	76,755	5,892	17,455,920
2017Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	61,159	86,040	7,986	16,633,428
2013Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	26,811	43,239	2,862	9,024,632
2014Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	27,917	46,387	2,760	7,970,527
2015Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	35,119	51,733	5,876	7,319,681
2016Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	26,317	41,765	4,262	7,365,999
2017Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	29,911	46,488	5,033	7,216,272
2013Y	United Illuminating Company	Iberdrola, S.A.	36,862	22,980	0	5,422,427
2014Y	United Illuminating Company	Iberdrola, S.A.	44,955	37,961	0	5,327,395
2015Y	United Illuminating Company	Iberdrola, S.A.	47,509	44,582	0	5,450,238
2016Y	United Illuminating Company	Iberdrola, S.A.	35,484	40,297	0	5,334,351
2017Y	United Illuminating Company	Iberdrola, S.A.	37,772	35,391	0	5,093,904
2013Y	Idaho Power Co.	IDACORP, Inc.	21,841	44,062	0	16,302,681
2014Y	Idaho Power Co.	IDACORP, Inc.	25,549	35,814	0	16,312,786

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2015Y	Idaho Power Co.	IDACORP, Inc.	21,157	39,575	80	15,518,629
2016Y	Idaho Power Co.	IDACORP, Inc.	20,845	42,924	0	15,381,629
2017Y	Idaho Power Co.	IDACORP, Inc.	22,428	46,084	0	16,706,603
2013Y	Kentucky Utilities Company	LKE	28,190	19,563	42	21,629,993
2014Y	Kentucky Utilities Company	LKE	34,679	18,365	94	21,986,858
2015Y	Kentucky Utilities Company	LKE	32,619	18,532	307	21,810,131
2016Y	Kentucky Utilities Company	LKE	32,262	22,509	817	21,437,963
2017Y	Kentucky Utilities Company	LKE	32,654	22,093	792	20,497,797
2013Y	Louisville Gas and Electric Company	LKE	11,099	15,059	42	14,478,316
2014Y	Louisville Gas and Electric Company	LKE	13,768	15,142	47	15,373,731
2015Y	Louisville Gas and Electric Company	LKE	12,601	14,306	610	13,502,213
2016Y	Louisville Gas and Electric Company	LKE	12,343	16,461	920	13,156,493
2017Y	Louisville Gas and Electric Company	LKE	12,706	16,456	1,032	13,133,134
2013Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	3,900	255	139	3,195,882
2014Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	4,111	261	166	3,331,202
2015Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	4,147	253	154	3,316,058
2016Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	4,897	256	107	3,303,555
2017Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	4,558	245	111	3,346,441
2013Y	Madison Gas and Electric Company	MGE Energy, Inc.	7,051	8,458	223	3,557,446
2014Y	Madison Gas and Electric Company	MGE Energy, Inc.	6,868	7,671	187	3,514,574
2015Y	Madison Gas and Electric Company	MGE Energy, Inc.	5,369	8,158	214	3,545,081
2016Y	Madison Gas and Electric Company	MGE Energy, Inc.	6,252	8,235	263	3,741,999
2017Y	Madison Gas and Electric Company	MGE Energy, Inc.	7,946	8,579	252	3,584,998
2013Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	260	10	10	99,446
2014Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	284	7	2	99,841
2015Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	370	7	6	99,902
2016Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	520	11	3	95,751
2017Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	563	2	5	95,101
2013Y	Massachusetts Electric Company	National Grid plc	61,952	199,119	2,873	11,080,137
2014Y	Massachusetts Electric Company	National Grid plc	75,178	236,180	1,922	10,608,963
2015Y	Massachusetts Electric Company	National Grid plc	100,307	275,385	1,473	8,699,117
2016Y	Massachusetts Electric Company	National Grid plc	87,111	256,142	2,222	6,486,573
2017Y	Massachusetts Electric Company	National Grid plc	77,302	263,936	2,196	6,427,679
2013Y	Narragansett Electric Company	National Grid plc	25,702	64,373	788	5,133,864

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Narragansett Electric Company	National Grid plc	31,778	87,876	670	5,006,934
2015Y	Narragansett Electric Company	National Grid plc	21,033	88,757	731	4,492,267
2016Y	Narragansett Electric Company	National Grid plc	20,198	72,972	473	3,954,763
2017Y	Narragansett Electric Company	National Grid plc	23,534	89,667	987	3,868,162
2013Y	National Grid Generation, LLC	National Grid plc	1,425	0	0	4,823,499
2014Y	National Grid Generation, LLC	National Grid plc	171	0	0	4,558,386
2015Y	National Grid Generation, LLC	National Grid plc	5,149	0	0	5,050,928
2016Y	National Grid Generation, LLC	National Grid plc	-3,347	0	0	4,561,590
2017Y	National Grid Generation, LLC	National Grid plc	84	0	0	3,213,471
2013Y	New England Power Company	National Grid plc	110	8	0	570,917
2014Y	New England Power Company	National Grid plc	384	1	0	565,418
2015Y	New England Power Company	National Grid plc	121	4	0	566,430
2016Y	New England Power Company	National Grid plc	380	2	0	314,990
2017Y	New England Power Company	National Grid plc	379	10	0	239,434
2013Y	Niagara Mohawk Power Corporation	National Grid plc	43,647	196,872	1,635	16,348,792
2014Y	Niagara Mohawk Power Corporation	National Grid plc	79,593	232,387	1,278	13,620,478
2015Y	Niagara Mohawk Power Corporation	National Grid plc	69,484	228,877	2,092	13,464,032
2016Y	Niagara Mohawk Power Corporation	National Grid plc	83,313	44,993	1,727	13,600,814
2017Y	Niagara Mohawk Power Corporation	National Grid plc	77,164	62,995	680	13,190,657
2013Y	Florida Power & Light Company	NextEra Energy, Inc.	134,779	137,369	4,799	107,373,794
2014Y	Florida Power & Light Company	NextEra Energy, Inc.	118,415	149,974	3,287	112,929,729
2015Y	Florida Power & Light Company	NextEra Energy, Inc.	110,574	102,185	4,597	119,405,262
2016Y	Florida Power & Light Company	NextEra Energy, Inc.	103,438	53,636	3,730	119,279,691
2017Y	Florida Power & Light Company	NextEra Energy, Inc.	97,736	57,440	8,069	117,873,183
2013Y	Northern Indiana Public Service Company	NiSource Inc.	21,117	576	923	17,468,011
2014Y	Northern Indiana Public Service Company	NiSource Inc.	20,345	505	967	18,186,288
2015Y	Northern Indiana Public Service Company	NiSource Inc.	19,140	371	928	16,758,427
2016Y	Northern Indiana Public Service Company	NiSource Inc.	17,248	543	1,222	16,831,194
2017Y	Northern Indiana Public Service Company	NiSource Inc.	15,422	739	1,484	16,725,564
2013Y	NorthWestern Corporation	NorthWestern Corporation	11,867	6,416	573	9,519,519
2014Y	NorthWestern Corporation	NorthWestern Corporation	12,706	6,400	615	10,006,908
2015Y	NorthWestern Corporation	NorthWestern Corporation	11,615	6,693	554	11,027,880
2016Y	NorthWestern Corporation	NorthWestern Corporation	10,627	6,601	503	9,037,846
2017Y	NorthWestern Corporation	NorthWestern Corporation	13,096	6,031	522	8,924,244

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	22,210	31,269	6,107	28,578,159
2014Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	21,054	35,892	8,242	30,234,927
2015Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	20,171	39,927	4,682	28,867,056
2016Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	21,973	50,081	4,713	29,762,475
2017Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	23,292	50,967	4,749	28,111,471
2013Y	Otter Tail Power Company	Otter Tail Corporation	13,422	8,132	623	6,219,751
2014Y	Otter Tail Power Company	Otter Tail Corporation	13,358	8,029	493	5,470,896
2015Y	Otter Tail Power Company	Otter Tail Corporation	12,791	8,864	313	4,709,464
2016Y	Otter Tail Power Company	Otter Tail Corporation	12,476	10,781	345	4,955,630
2017Y	Otter Tail Power Company	Otter Tail Corporation	12,912	9,358	339	5,040,591
2013Y	Pacific Gas and Electric Company	PG&E Corporation	248,874	616,738	13,922	88,322,913
2014Y	Pacific Gas and Electric Company	PG&E Corporation	216,187	614,606	10,382	88,189,685
2015Y	Pacific Gas and Electric Company	PG&E Corporation	222,794	631,523	2,979	87,981,023
2016Y	Pacific Gas and Electric Company	PG&E Corporation	212,307	611,149	2,273	85,067,412
2017Y	Pacific Gas and Electric Company	PG&E Corporation	215,958	512,904	1,195	88,175,650
2013Y	Arizona Public Service Company	Pinnacle West Capital Corporation	52,597	77,723	9,332	32,087,545
2014Y	Arizona Public Service Company	Pinnacle West Capital Corporation	52,544	60,160	9,974	32,951,388
2015Y	Arizona Public Service Company	Pinnacle West Capital Corporation	52,455	55,010	11,296	33,628,854
2016Y	Arizona Public Service Company	Pinnacle West Capital Corporation	54,257	59,023	12,389	31,928,046
2017Y	Arizona Public Service Company	Pinnacle West Capital Corporation	59,041	54,410	13,872	30,910,170
2013Y	Public Service Company of New Mexico	PNM Resources, Inc.	15,288	961	5,299	12,001,980
2014Y	Public Service Company of New Mexico	PNM Resources, Inc.	15,368	748	4,814	11,836,387
2015Y	Public Service Company of New Mexico	PNM Resources, Inc.	14,956	1,283	4,792	11,541,512
2016Y	Public Service Company of New Mexico	PNM Resources, Inc.	14,810	644	4,099	12,280,191
2017Y	Public Service Company of New Mexico	PNM Resources, Inc.	15,166	457	4,385	12,454,143
2013Y	Portland General Electric Company	Portland General Electric Company	48,824	13,288	0	21,226,863
2014Y	Portland General Electric Company	Portland General Electric Company	51,831	14,179	0	21,080,082
2015Y	Portland General Electric Company	Portland General Electric Company	54,700	15,058	0	20,859,230
2016Y	Portland General Electric Company	Portland General Electric Company	56,434	14,192	0	21,247,271
2017Y	Portland General Electric Company	Portland General Electric Company	58,493	15,696	0	21,328,945
2013Y	PPL Electric Utilities Corporation	PPL Corporation	74,898	81,586	2,533	37,712,878
2014Y	PPL Electric Utilities Corporation	PPL Corporation	78,943	91,321	2,343	38,005,667
2015Y	PPL Electric Utilities Corporation	PPL Corporation	86,548	105,952	2,233	37,967,738
2016Y	PPL Electric Utilities Corporation	PPL Corporation	82,383	94,624	1,638	37,618,811

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	PPL Electric Utilities Corporation	PPL Corporation	69,181	99,779	1,597	36,939,991
2013Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	285,256	225,491	743	44,103,026
2014Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	310,842	196,580	655	42,728,622
2015Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	290,553	174,407	3,828	43,533,905
2016Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	228,368	165,366	1,073	42,288,312
2017Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	239,979	122,699	296	40,894,038
2013Y	Puget Sound Energy, Inc.	Puget Holdings LLC	51,298	105,724	288	26,265,216
2014Y	Puget Sound Energy, Inc.	Puget Holdings LLC	59,106	113,232	526	21,968,767
2015Y	Puget Sound Energy, Inc.	Puget Holdings LLC	49,097	118,438	389	28,183,148
2016Y	Puget Sound Energy, Inc.	Puget Holdings LLC	48,803	114,318	384	29,143,765
2017Y	Puget Sound Energy, Inc.	Puget Holdings LLC	49,274	126,051	769	27,227,367
2013Y	South Carolina Electric & Gas Co.	SCANA Corporation	46,737	7,698	1,625	22,326,578
2014Y	South Carolina Electric & Gas Co.	SCANA Corporation	48,801	9,578	1,636	23,332,942
2015Y	South Carolina Electric & Gas Co.	SCANA Corporation	47,994	13,430	1,755	23,114,845
2016Y	South Carolina Electric & Gas Co.	SCANA Corporation	47,831	14,770	1,425	23,471,194
2017Y	South Carolina Electric & Gas Co.	SCANA Corporation	46,520	14,367	1,469	22,879,069
2013Y	Oncor Electric Delivery Company LLC	Sempra Energy	19,606	64,952	1	112,312,279
2014Y	Oncor Electric Delivery Company LLC	Sempra Energy	21,234	63,760	87	114,905,829
2015Y	Oncor Electric Delivery Company LLC	Sempra Energy	18,574	49,259	28	116,594,625
2016Y	Oncor Electric Delivery Company LLC	Sempra Energy	17,798	57,611	0	115,791,379
2017Y	Oncor Electric Delivery Company LLC	Sempra Energy	18,882	46,298	2	117,017,075
2013Y	San Diego Gas & Electric Co.	Sempra Energy	53,797	148,373	0	32,916,382
2014Y	San Diego Gas & Electric Co.	Sempra Energy	43,897	157,667	0	30,952,957
2015Y	San Diego Gas & Electric Co.	Sempra Energy	45,453	173,383	0	33,132,033
2016Y	San Diego Gas & Electric Co.	Sempra Energy	44,111	208,005	0	29,443,890
2017Y	San Diego Gas & Electric Co.	Sempra Energy	46,369	174,580	0	29,300,970
2013Y	Alabama Power Company	Southern Company	90,103	34,907	9,154	66,309,626
2014Y	Alabama Power Company	Southern Company	100,081	38,459	8,779	67,155,314
2015Y	Alabama Power Company	Southern Company	97,311	40,201	9,180	63,847,336
2016Y	Alabama Power Company	Southern Company	94,943	42,361	6,972	63,873,423
2017Y	Alabama Power Company	Southern Company	89,807	48,938	6,618	63,290,561
2013Y	Georgia Power Company	Southern Company	135,041	72,749	43,330	84,726,779
2014Y	Georgia Power Company	Southern Company	154,531	88,588	55,105	89,190,865
2015Y	Georgia Power Company	Southern Company	154,823	94,667	56,593	87,859,128

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Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Georgia Power Company	Southern Company	154,466	98,184	63,588	89,686,468
2017Y	Georgia Power Company	Southern Company	137,123	83,472	58,694	86,478,222
2013Y	Gulf Power Company	Southern Company	21,295	35,993	1,186	14,909,545
2014Y	Gulf Power Company	Southern Company	25,421	25,819	1,460	16,028,868
2015Y	Gulf Power Company	Southern Company	24,629	30,098	1,391	14,031,937
2016Y	Gulf Power Company	Southern Company	25,341	23,677	1,132	14,616,769
2017Y	Gulf Power Company	Southern Company	26,321	27,078	1,391	15,445,454
2013Y	Mississippi Power Company	Southern Company	17,838	5,798	4,175	14,591,834
2014Y	Mississippi Power Company	Southern Company	16,158	7,922	4,941	17,059,643
2015Y	Mississippi Power Company	Southern Company	13,746	10,273	4,742	16,487,788
2016Y	Mississippi Power Company	Southern Company	16,769	10,008	4,293	14,866,485
2017Y	Mississippi Power Company	Southern Company	15,719	9,078	2,884	15,283,882
2013Y	UGI Utilities, Inc.	UGI Corporation	2,969	442	36	1,000,701
2014Y	UGI Utilities, Inc.	UGI Corporation	3,220	363	31	975,771
2015Y	UGI Utilities, Inc.	UGI Corporation	3,361	309	24	990,384
2016Y	UGI Utilities, Inc.	UGI Corporation	2,655	266	25	977,118
2017Y	UGI Utilities, Inc.	UGI Corporation	3,114	316	30	956,654
2013Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	2,895	3,924	619	505,418
2014Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,084	3,733	1,013	533,929
2015Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,619	4,772	1,201	460,811
2016Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	3,067	3,739	993	444,498
2017Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	2,810	4,203	0	455,496
2013Y	Unitil Energy Systems, Inc.	Unitil Corporation	3,763	2,901	0	1,234,354
2014Y	Unitil Energy Systems, Inc.	Unitil Corporation	3,895	3,091	0	1,230,055
2015Y	Unitil Energy Systems, Inc.	Unitil Corporation	3,697	2,469	0	1,229,879
2016Y	Unitil Energy Systems, Inc.	Unitil Corporation	3,577	2,637	0	1,203,404
2017Y	Unitil Energy Systems, Inc.	Unitil Corporation	3,410	3,076	0	1,215,797
2013Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	6,427	619	13,259	5,993,477
2014Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	5,880	592	12,227	6,240,584
2015Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	6,189	323	8,294	5,795,918
2016Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	5,908	617	10,444	5,610,259
2017Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	6,402	552	9,117	5,220,819
2013Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	54,545	51,157	845	32,555,334
2014Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	53,327	50,321	893	32,942,828

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	54,234	65,658	680	35,818,700
2016Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	52,387	48,032	355	35,894,209
2017Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	51,647	46,852	80	34,951,750
2013Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	15,454	25,538	2	16,129,893
2014Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	15,788	24,665	1	14,557,949
2015Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	16,639	24,776	2	14,839,077
2016Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	16,520	20,638	0	14,636,889
2017Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	14,157	21,657	0	14,814,995
2013Y	Kansas Gas and Electric Company	Westar Energy, Inc.	12,619	1,827	0	10,605,055
2014Y	Kansas Gas and Electric Company	Westar Energy, Inc.	15,741	1,765	0	10,800,465
2015Y	Kansas Gas and Electric Company	Westar Energy, Inc.	13,961	1,713	1	10,761,626
2016Y	Kansas Gas and Electric Company	Westar Energy, Inc.	15,625	1,621	0	11,297,034
2017Y	Kansas Gas and Electric Company	Westar Energy, Inc.	14,004	1,559	0	10,847,878
2013Y	Westar Energy (KPL)	Westar Energy, Inc.	14,214	1,851	0	17,484,374
2014Y	Westar Energy (KPL)	Westar Energy, Inc.	13,976	1,868	0	18,531,716
2015Y	Westar Energy (KPL)	Westar Energy, Inc.	15,837	1,933	1	17,180,535
2016Y	Westar Energy (KPL)	Westar Energy, Inc.	17,854	1,935	0	16,555,817
2017Y	Westar Energy (KPL)	Westar Energy, Inc.	17,040	1,942	0	18,790,662
2013Y	Northern States Power Company - MN	Xcel Energy Inc.	55,250	84,666	18	37,474,524
2014Y	Northern States Power Company - MN	Xcel Energy Inc.	58,047	124,080	9	39,129,144
2015Y	Northern States Power Company - MN	Xcel Energy Inc.	55,350	69,454	2	39,484,126
2016Y	Northern States Power Company - MN	Xcel Energy Inc.	55,996	89,936	1	41,519,021
2017Y	Northern States Power Company - MN	Xcel Energy Inc.	55,401	106,677	5	40,720,489
2013Y	Northern States Power Company - WI	Xcel Energy Inc.	10,015	10,571	82	6,562,368
2014Y	Northern States Power Company - WI	Xcel Energy Inc.	10,384	11,134	80	6,750,889
2015Y	Northern States Power Company - WI	Xcel Energy Inc.	9,835	11,158	72	6,647,300
2016Y	Northern States Power Company - WI	Xcel Energy Inc.	9,336	12,318	55	6,641,542
2017Y	Northern States Power Company - WI	Xcel Energy Inc.	9,663	12,252	53	6,727,740
2013Y	Public Service Company of Colorado	Xcel Energy Inc.	38,200	125,572	641	33,450,187
2014Y	Public Service Company of Colorado	Xcel Energy Inc.	37,413	130,409	528	32,498,488
2015Y	Public Service Company of Colorado	Xcel Energy Inc.	33,293	121,395	589	32,396,474
2016Y	Public Service Company of Colorado	Xcel Energy Inc.	34,860	107,952	651	34,472,722
2017Y	Public Service Company of Colorado	Xcel Energy Inc.	34,160	113,706	627	36,486,396
2013Y	Southwestern Public Service Company	Xcel Energy Inc.	15,423	15,588	189	28,292,788

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Year	Company Name	Ultimate Parent Company Name	Total Customer Accounts Expense ($000)	Total Customer Svc & Informational Expense ($000)	Total Sales Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Southwestern Public Service Company	Xcel Energy Inc.	15,673	15,174	188	28,265,391
2015Y	Southwestern Public Service Company	Xcel Energy Inc.	15,664	16,439	149	28,414,831
2016Y	Southwestern Public Service Company	Xcel Energy Inc.	20,045	19,019	136	28,383,129
2017Y	Southwestern Public Service Company	Xcel Energy Inc.	18,382	18,484	128	27,124,064
		Total	25,600,449	31,091,138	1,020,985	14,663,555,802

A&G Rankings [2013-2017]

Holding Company	A&G O&M	Total Sales of Elect. Volume	Total A&G/MWh	Ranking
CenterPoint Energy, Inc.	1,124,431,000	421,479,989	2.67	1
AEP	2,965,973,000	1,061,025,937	2.80	2
Berkshire Hathaway Inc.	1,836,625,000	647,595,062	2.84	3
FirstEnergy Corp.	2,445,607,000	795,797,359	3.07	4
NextEra Energy, Inc.	1,887,794,000	576,861,659	3.27	5
Dominion Energy, Inc.	1,796,341,000	424,814,207	4.23	6
CMS Energy Corporation	764,720,000	180,393,075	4.24	7
Puget Holdings LLC	577,363,000	132,788,263	4.35	8
OGE Energy Corp.	642,314,000	145,554,088	4.41	9
Public Service Enterprise Group	950,335,000	213,547,903	4.45	10
PPL Corporation	891,792,000	188,245,085	4.74	11
Cleco Partners LP	282,366,000	58,299,323	4.84	12
WEC Energy Group, Inc.	1,210,349,000	247,141,624	4.90	13
Entergy Corporation	3,677,412,000	748,921,761	4.91	14
Ameren Corporation	2,031,736,000	396,912,264	5.12	15
ALLETE, Inc.	385,436,000	74,330,795	5.19	16
Duke Energy Corporation	6,640,557,000	1,280,342,802	5.19	17
Xcel Energy Inc.	2,876,260,000	541,441,613	5.31	18
LKE	947,428,654	177,006,629	5.35	19
Exelon Corporation	5,661,971,000	1,034,415,389	5.47	20
Southern Company	5,101,599,000	923,010,412	5.53	21
Pinnacle West Capital Corp	943,750,000	161,506,003	5.84	22
Avista Corporation	373,418,000	63,822,212	5.85	23
Sempra Energy	4,289,437,000	732,367,419	5.86	24

A&G Rankings [2013-2017]

Holding Company	A&G O&M	Total Sales of Elect. Volume	Total A&G/MWh	Ranking
Alliant Energy Corporation	953,017,000	158,149,961	6.03	25
AES Corporation	1,055,499,000	157,380,054	6.71	26
SCANA Corporation	885,145,000	131,504,208	6.73	27
Emera Incorporated	725,688,000	106,439,317	6.82	28
Vectren Corporation	198,134,000	28,861,057	6.87	29
MDU Resources Group, Inc.	114,074,000	16,493,138	6.92	30
Westar Energy, Inc.	1,043,595,000	146,818,676	7.11	31
UGI Corporation	36,654,000	4,900,628	7.48	32
DTE Energy Company	1,734,419,000	230,365,093	7.53	33
NorthWestern Corporation	367,391,000	48,516,397	7.57	34
Great Plains Energy Inc	1,198,543,000	149,872,607	8.00	35
Otter Tail Corporation	213,607,000	26,396,332	8.09	36
Iberdrola, S.A.	1,279,036,000	157,875,239	8.10	37
Portland General Electric Co	858,523,000	105,742,391	8.12	38
DQE Holdings LLC	557,801,000	67,127,889	8.31	39
Eversource Energy	2,414,279,000	289,678,343	8.33	40
Wisconsin River Power Co	6,137,000	719,940	8.52	41
Unitil Corporation	73,044,000	8,513,641	8.58	42
Black Hills Corporation	284,467,000	32,232,125	8.83	43
IDACORP, Inc.	736,901,000	80,222,328	9.19	44
Algonquin Power & Utilities	278,402,000	29,685,318	9.38	45
Caisse de dépôt et	222,644,000	23,640,213	9.42	46
MGE Energy, Inc.	174,332,000	17,944,098	9.72	47
Fortis Inc.	957,836,000	90,696,008	10.56	48

A&G Rankings [2013-2017]

Holding Company	A&G O&M	Total Sales of Elect. Volume	Total A&G/MWh	Ranking
El Paso Electric Company	597,214,000	54,312,529	11.00	49
Edison International	5,388,228,000	476,972,294	11.30	50
PNM Resources, Inc.	707,960,000	60,114,213	11.78	51
NiSource Inc.	1,040,189,000	85,969,484	12.10	52
PG&E Corporation	5,557,300,000	437,736,683	12.70	53
Balfour Beatty Infrastructure	61,577,000	4,147,629	14.85	54
Consolidated Edison, Inc.	4,836,328,000	264,071,298	18.31	55
National Grid plc	4,408,386,000	160,448,295	27.48	56
Mt. Carmel Public Utility Co	14,399,000	490,041	29.38	57
Grand Total	89,285,763,654	14,881,658,340		

Q1	5.12
Q2	6.87
Q3	8.83
Industry Avg.	6.00

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Dayton Power and Light Company	AES Corporation	84,976	19,416,290
2014Y	Dayton Power and Light Company	AES Corporation	71,385	18,643,195
2015Y	Dayton Power and Light Company	AES Corporation	74,868	16,433,036
2016Y	Dayton Power and Light Company	AES Corporation	78,267	16,158,129
2017Y	Dayton Power and Light Company	AES Corporation	89,056	12,236,126
2013Y	Indianapolis Power & Light Company	AES Corporation	139,732	16,033,922
2014Y	Indianapolis Power & Light Company	AES Corporation	125,982	16,391,321
2015Y	Indianapolis Power & Light Company	AES Corporation	127,068	14,397,561
2016Y	Indianapolis Power & Light Company	AES Corporation	133,658	14,185,985
2017Y	Indianapolis Power & Light Company	AES Corporation	130,507	13,484,489
2013Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	44,700	5,620,276
2014Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	45,640	5,131,750
2015Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	46,209	4,940,028
2016Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	49,080	4,950,707
2017Y	Empire District Electric Company	Algonquin Power & Utilities Corp.	53,163	4,841,355
2013Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	9,544	552,273
2014Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	8,352	910,825
2015Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	7,133	933,262
2016Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	7,886	910,242
2017Y	Liberty Utilities (Granite State Electric) Corp.	Algonquin Power & Utilities Corp.	6,695	894,600
2013Y	ALLETE (Minnesota Power)	ALLETE, Inc.	69,292	13,264,062
2014Y	ALLETE (Minnesota Power)	ALLETE, Inc.	80,821	13,942,499
2015Y	ALLETE (Minnesota Power)	ALLETE, Inc.	73,416	14,369,559
2016Y	ALLETE (Minnesota Power)	ALLETE, Inc.	60,228	14,147,335

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	ALLETE (Minnesota Power)	ALLETE, Inc.	87,232	14,692,658
2013Y	Superior Water, Light and Power Company	ALLETE, Inc.	2,792	687,209
2014Y	Superior Water, Light and Power Company	ALLETE, Inc.	2,590	770,427
2015Y	Superior Water, Light and Power Company	ALLETE, Inc.	3,102	788,342
2016Y	Superior Water, Light and Power Company	ALLETE, Inc.	2,871	820,880
2017Y	Superior Water, Light and Power Company	ALLETE, Inc.	3,092	847,824
2013Y	Interstate Power and Light Company	Alliant Energy Corporation	92,498	17,194,056
2014Y	Interstate Power and Light Company	Alliant Energy Corporation	97,904	16,871,181
2015Y	Interstate Power and Light Company	Alliant Energy Corporation	103,499	16,703,172
2016Y	Interstate Power and Light Company	Alliant Energy Corporation	115,224	16,662,731
2017Y	Interstate Power and Light Company	Alliant Energy Corporation	117,573	17,406,995
2013Y	Wisconsin Power and Light Company	Alliant Energy Corporation	81,752	14,862,652
2014Y	Wisconsin Power and Light Company	Alliant Energy Corporation	81,895	14,603,712
2015Y	Wisconsin Power and Light Company	Alliant Energy Corporation	85,707	15,199,013
2016Y	Wisconsin Power and Light Company	Alliant Energy Corporation	88,857	14,480,783
2017Y	Wisconsin Power and Light Company	Alliant Energy Corporation	88,108	14,165,666
2013Y	Ameren Illinois Company	Ameren Corporation	140,454	38,012,834
2014Y	Ameren Illinois Company	Ameren Corporation	151,672	37,915,282
2015Y	Ameren Illinois Company	Ameren Corporation	151,661	36,850,871
2016Y	Ameren Illinois Company	Ameren Corporation	149,707	36,754,294
2017Y	Ameren Illinois Company	Ameren Corporation	157,181	35,537,431
2013Y	Union Electric Company	Ameren Corporation	251,904	43,158,138
2014Y	Union Electric Company	Ameren Corporation	278,701	43,192,724
2015Y	Union Electric Company	Ameren Corporation	264,623	43,255,846

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Union Electric Company	Ameren Corporation	251,783	39,997,209
2017Y	Union Electric Company	Ameren Corporation	234,050	42,237,635
2013Y	AEP Generating Company	American Electric Power Company, Inc.	5,909	10,546,276
2014Y	AEP Generating Company	American Electric Power Company, Inc.	6,076	11,675,906
2015Y	AEP Generating Company	American Electric Power Company, Inc.	8,563	12,994,269
2016Y	AEP Generating Company	American Electric Power Company, Inc.	7,548	13,491,086
2017Y	AEP Generating Company	American Electric Power Company, Inc.	4,815	6,069,003
2013Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA
2014Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	43,193	47,215,732
2015Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA
2016Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA
2017Y	AEP Generation Resources Inc.	American Electric Power Company, Inc.	NA	NA
2013Y	AEP Texas Central Company	American Electric Power Company, Inc.	43,644	NA
2014Y	AEP Texas Central Company	American Electric Power Company, Inc.	47,220	NA
2015Y	AEP Texas Central Company	American Electric Power Company, Inc.	52,017	NA
2016Y	AEP Texas Central Company	American Electric Power Company, Inc.	47,242	NA
2017Y	AEP Texas Central Company	American Electric Power Company, Inc.	NA	NA
2013Y	AEP Texas North Company	American Electric Power Company, Inc.	16,439	2,435,181
2014Y	AEP Texas North Company	American Electric Power Company, Inc.	17,109	1,741,758
2015Y	AEP Texas North Company	American Electric Power Company, Inc.	17,969	1,368,742
2016Y	AEP Texas North Company	American Electric Power Company, Inc.	17,352	1,381,295
2017Y	AEP Texas North Company	American Electric Power Company, Inc.	NA	NA
2013Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA
2014Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA
2016Y	AEP Texas, Inc.	American Electric Power Company, Inc.	NA	NA
2017Y	AEP Texas, Inc.	American Electric Power Company, Inc.	64,374	923,791
2013Y	Appalachian Power Company	American Electric Power Company, Inc.	104,512	47,596,529
2014Y	Appalachian Power Company	American Electric Power Company, Inc.	111,163	35,769,358
2015Y	Appalachian Power Company	American Electric Power Company, Inc.	104,606	34,847,578
2016Y	Appalachian Power Company	American Electric Power Company, Inc.	104,282	34,862,820
2017Y	Appalachian Power Company	American Electric Power Company, Inc.	101,376	33,601,395
2013Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	115,582	38,036,953
2014Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	126,248	35,331,017
2015Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	115,453	30,404,900
2016Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	114,698	28,379,413
2017Y	Indiana Michigan Power Company	American Electric Power Company, Inc.	107,631	29,819,953
2013Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	18,249	5,475,276
2014Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	16,124	5,936,251
2015Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	13,207	5,186,234
2016Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	13,933	4,985,411
2017Y	Indiana-Kentucky Electric Corporation	American Electric Power Company, Inc.	12,801	6,032,062
2013Y	Kentucky Power Company	American Electric Power Company, Inc.	19,790	9,933,527
2014Y	Kentucky Power Company	American Electric Power Company, Inc.	21,802	11,993,933
2015Y	Kentucky Power Company	American Electric Power Company, Inc.	22,615	8,700,986
2016Y	Kentucky Power Company	American Electric Power Company, Inc.	21,711	7,276,047
2017Y	Kentucky Power Company	American Electric Power Company, Inc.	24,852	7,106,360
2013Y	Kingsport Power Company	American Electric Power Company, Inc.	1,790	2,045,738

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Kingsport Power Company	American Electric Power Company, Inc.	1,908	2,120,716
2015Y	Kingsport Power Company	American Electric Power Company, Inc.	2,925	2,086,994
2016Y	Kingsport Power Company	American Electric Power Company, Inc.	2,572	2,038,552
2017Y	Kingsport Power Company	American Electric Power Company, Inc.	2,505	1,971,080
2013Y	Ohio Power Company	American Electric Power Company, Inc.	137,830	60,639,578
2014Y	Ohio Power Company	American Electric Power Company, Inc.	84,436	15,591,760
2015Y	Ohio Power Company	American Electric Power Company, Inc.	79,307	45,685,751
2016Y	Ohio Power Company	American Electric Power Company, Inc.	79,284	45,870,876
2017Y	Ohio Power Company	American Electric Power Company, Inc.	78,682	45,688,514
2013Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	31,805	10,499,577
2014Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	33,237	11,400,464
2015Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	24,520	8,872,645
2016Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	23,545	9,919,829
2017Y	Ohio Valley Electric Corporation	American Electric Power Company, Inc.	31,441	11,881,430
2013Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	51,846	19,239,394
2014Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	58,605	19,517,893
2015Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	56,457	18,916,965
2016Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	55,328	19,425,199
2017Y	Public Service Company of Oklahoma	American Electric Power Company, Inc.	55,904	19,052,676
2013Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	64,549	28,553,233
2014Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	72,366	28,644,882
2015Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	70,386	27,269,400
2016Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	75,617	26,169,526
2017Y	Southwestern Electric Power Company	American Electric Power Company, Inc.	68,484	26,257,034

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Wheeling Power Company	American Electric Power Company, Inc.	2,187	2,703,781
2014Y	Wheeling Power Company	American Electric Power Company, Inc.	2,667	3,269,892
2015Y	Wheeling Power Company	American Electric Power Company, Inc.	8,230	4,451,364
2016Y	Wheeling Power Company	American Electric Power Company, Inc.	9,057	5,106,836
2017Y	Wheeling Power Company	American Electric Power Company, Inc.	8,398	5,015,316
2013Y	Alaska Electric Light and Power Company	Avista Corporation	4,316	377,005
2014Y	Alaska Electric Light and Power Company	Avista Corporation	4,191	422,784
2015Y	Alaska Electric Light and Power Company	Avista Corporation	4,429	398,066
2016Y	Alaska Electric Light and Power Company	Avista Corporation	4,330	395,154
2017Y	Alaska Electric Light and Power Company	Avista Corporation	4,576	414,210
2013Y	Avista Corporation	Avista Corporation	64,056	13,318,994
2014Y	Avista Corporation	Avista Corporation	67,943	12,839,533
2015Y	Avista Corporation	Avista Corporation	73,623	11,942,035
2016Y	Avista Corporation	Avista Corporation	73,986	11,733,626
2017Y	Avista Corporation	Avista Corporation	71,968	11,980,805
2013Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	11,337	881,022
2014Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	9,853	845,665
2015Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	17,556	844,127
2016Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	12,036	831,622
2017Y	Upper Peninsula Power Company	Balfour Beatty Infrastructure Partners, L.P.	10,795	745,193
2013Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	77,455	32,680,735
2014Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	72,945	32,499,927
2015Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	68,170	31,832,657
2016Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	63,771	32,475,023

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	MidAmerican Energy Company	Berkshire Hathaway Inc.	59,530	33,727,302
2013Y	Nevada Power Company	Berkshire Hathaway Inc.	139,802	24,064,426
2014Y	Nevada Power Company	Berkshire Hathaway Inc.	115,901	22,745,488
2015Y	Nevada Power Company	Berkshire Hathaway Inc.	99,676	25,481,621
2016Y	Nevada Power Company	Berkshire Hathaway Inc.	99,466	25,062,084
2017Y	Nevada Power Company	Berkshire Hathaway Inc.	104,964	23,751,206
2013Y	PacifiCorp	Berkshire Hathaway Inc.	175,800	65,869,008
2014Y	PacifiCorp	Berkshire Hathaway Inc.	103,887	65,269,524
2015Y	PacifiCorp	Berkshire Hathaway Inc.	134,217	63,530,663
2016Y	PacifiCorp	Berkshire Hathaway Inc.	129,633	60,958,902
2017Y	PacifiCorp	Berkshire Hathaway Inc.	142,110	62,468,319
2013Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	59,898	9,185,572
2014Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	50,018	8,882,408
2015Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	46,684	8,911,051
2016Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	47,076	9,000,293
2017Y	Sierra Pacific Power Company	Berkshire Hathaway Inc.	45,622	9,198,853
2013Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	22,454	2,028,643
2014Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	20,287	1,957,695
2015Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	20,082	1,959,505
2016Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	19,732	1,985,177
2017Y	Black Hills Colorado Electric Utility Company, LP	Black Hills Corporation	19,595	1,932,972
2013Y	Black Hills Power, Inc.	Black Hills Corporation	30,256	3,084,298
2014Y	Black Hills Power, Inc.	Black Hills Corporation	29,891	2,905,098
2015Y	Black Hills Power, Inc.	Black Hills Corporation	26,141	2,873,371

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Black Hills Power, Inc.	Black Hills Corporation	23,125	2,611,946
2017Y	Black Hills Power, Inc.	Black Hills Corporation	25,139	2,992,386
2013Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	7,880	1,635,140
2014Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	9,082	1,639,680
2015Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	10,740	1,418,697
2016Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	9,537	1,559,870
2017Y	Cheyenne Light, Fuel and Power Company	Black Hills Corporation	10,526	1,647,647
2013Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	51,916	4,853,495
2014Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	46,640	4,713,347
2015Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	43,845	4,751,076
2016Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	39,113	4,688,744
2017Y	Green Mountain Power Corporation	Caisse de dépôt et placement du Québec	41,130	4,633,551
2013Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	212,275	79,984,965
2014Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	224,780	81,839,060
2015Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	228,393	84,190,647
2016Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	223,340	86,828,900
2017Y	CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	235,643	88,636,417
2013Y	Cleco Power LLC	Cleco Partners LP	54,127	11,115,732
2014Y	Cleco Power LLC	Cleco Partners LP	57,395	12,201,940
2015Y	Cleco Power LLC	Cleco Partners LP	60,469	12,105,640
2016Y	Cleco Power LLC	Cleco Partners LP	55,673	11,596,427
2017Y	Cleco Power LLC	Cleco Partners LP	54,702	11,279,584
2013Y	Consumers Energy Company	CMS Energy Corporation	178,714	35,276,791
2014Y	Consumers Energy Company	CMS Energy Corporation	144,938	35,893,242

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Consumers Energy Company	CMS Energy Corporation	153,594	36,357,438
2016Y	Consumers Energy Company	CMS Energy Corporation	142,178	36,746,531
2017Y	Consumers Energy Company	CMS Energy Corporation	145,296	36,119,073
2013Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	972,467	47,335,320
2014Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	973,181	46,406,542
2015Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	886,291	47,202,850
2016Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	866,797	47,450,242
2017Y	Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.	669,606	46,342,045
2013Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	77,322	4,263,699
2014Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	79,127	4,256,408
2015Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	77,737	4,415,840
2016Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	65,884	4,315,576
2017Y	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	63,266	4,056,841
2013Y	Rockland Electric Company	Consolidated Edison, Inc.	23,683	1,642,857
2014Y	Rockland Electric Company	Consolidated Edison, Inc.	20,925	1,610,904
2015Y	Rockland Electric Company	Consolidated Edison, Inc.	20,296	1,631,351
2016Y	Rockland Electric Company	Consolidated Edison, Inc.	19,309	1,601,861
2017Y	Rockland Electric Company	Consolidated Edison, Inc.	20,437	1,538,962
2013Y	Virginia Electric and Power Company	Dominion Energy, Inc.	388,641	82,852,117
2014Y	Virginia Electric and Power Company	Dominion Energy, Inc.	330,798	83,938,195
2015Y	Virginia Electric and Power Company	Dominion Energy, Inc.	354,234	85,178,907
2016Y	Virginia Electric and Power Company	Dominion Energy, Inc.	377,040	87,875,099
2017Y	Virginia Electric and Power Company	Dominion Energy, Inc.	345,628	84,969,889
2013Y	Duquesne Light Company	DQE Holdings LLC	101,997	14,007,273

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Duquesne Light Company	DQE Holdings LLC	104,953	13,747,339
2015Y	Duquesne Light Company	DQE Holdings LLC	115,862	13,503,863
2016Y	Duquesne Light Company	DQE Holdings LLC	120,524	13,172,591
2017Y	Duquesne Light Company	DQE Holdings LLC	114,465	12,696,823
2013Y	DTE Electric Company	DTE Energy Company	377,304	47,062,371
2014Y	DTE Electric Company	DTE Energy Company	316,623	46,076,577
2015Y	DTE Electric Company	DTE Energy Company	314,033	46,281,765
2016Y	DTE Electric Company	DTE Energy Company	357,938	45,998,164
2017Y	DTE Electric Company	DTE Energy Company	368,521	44,946,216
2013Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	575,778	85,789,697
2014Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	460,331	87,645,520
2015Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	532,642	87,375,571
2016Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	491,096	88,544,715
2017Y	Duke Energy Carolinas, LLC	Duke Energy Corporation	414,143	87,306,564
2013Y	Duke Energy Florida, LLC	Duke Energy Corporation	279,602	38,164,155
2014Y	Duke Energy Florida, LLC	Duke Energy Corporation	237,312	38,728,049
2015Y	Duke Energy Florida, LLC	Duke Energy Corporation	242,876	39,989,379
2016Y	Duke Energy Florida, LLC	Duke Energy Corporation	257,542	40,660,935
2017Y	Duke Energy Florida, LLC	Duke Energy Corporation	217,891	40,290,293
2013Y	Duke Energy Indiana, LLC	Duke Energy Corporation	197,917	33,714,982
2014Y	Duke Energy Indiana, LLC	Duke Energy Corporation	155,383	33,433,620
2015Y	Duke Energy Indiana, LLC	Duke Energy Corporation	161,178	33,517,569
2016Y	Duke Energy Indiana, LLC	Duke Energy Corporation	152,284	34,368,826
2017Y	Duke Energy Indiana, LLC	Duke Energy Corporation	140,185	33,145,670

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	23,632	4,546,692
2014Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	18,599	4,447,988
2015Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	20,732	5,277,786
2016Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	19,370	4,672,987
2017Y	Duke Energy Kentucky, Inc.	Duke Energy Corporation	19,497	4,908,072
2013Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	143,718	39,309,749
2014Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	80,542	27,741,596
2015Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	86,660	20,805,363
2016Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	54,281	21,320,518
2017Y	Duke Energy Ohio, Inc.	Duke Energy Corporation	56,553	20,805,946
2013Y	Duke Energy Progress, LLC	Duke Energy Corporation	349,517	60,204,063
2014Y	Duke Energy Progress, LLC	Duke Energy Corporation	296,661	62,871,047
2015Y	Duke Energy Progress, LLC	Duke Energy Corporation	299,516	64,880,560
2016Y	Duke Energy Progress, LLC	Duke Energy Corporation	340,666	69,052,154
2017Y	Duke Energy Progress, LLC	Duke Energy Corporation	314,453	66,822,736
2013Y	Southern California Edison Company	Edison International	1,190,561	90,552,978
2014Y	Southern California Edison Company	Edison International	1,164,602	116,437,195
2015Y	Southern California Edison Company	Edison International	1,058,831	90,495,397
2016Y	Southern California Edison Company	Edison International	999,751	88,194,998
2017Y	Southern California Edison Company	Edison International	974,483	91,291,726
2013Y	El Paso Electric Company	El Paso Electric Company	125,348	10,884,241
2014Y	El Paso Electric Company	El Paso Electric Company	121,061	11,009,422
2015Y	El Paso Electric Company	El Paso Electric Company	116,878	10,915,601
2016Y	El Paso Electric Company	El Paso Electric Company	116,065	10,598,511

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	El Paso Electric Company	El Paso Electric Company	117,862	10,904,754
2013Y	Emera Maine	Emera Incorporated	12,342	1,869,923
2014Y	Emera Maine	Emera Incorporated	16,305	2,344,241
2015Y	Emera Maine	Emera Incorporated	18,529	2,325,046
2016Y	Emera Maine	Emera Incorporated	15,928	2,217,874
2017Y	Emera Maine	Emera Incorporated	15,413	2,270,073
2013Y	Maine Public Service Company	Emera Incorporated	3,641	NA
2014Y	Maine Public Service Company	Emera Incorporated	NA	NA
2015Y	Maine Public Service Company	Emera Incorporated	NA	NA
2016Y	Maine Public Service Company	Emera Incorporated	NA	NA
2017Y	Maine Public Service Company	Emera Incorporated	NA	NA
2013Y	Tampa Electric Company	Emera Incorporated	145,127	18,639,927
2014Y	Tampa Electric Company	Emera Incorporated	132,051	18,784,911
2015Y	Tampa Electric Company	Emera Incorporated	123,601	19,121,762
2016Y	Tampa Electric Company	Emera Incorporated	123,403	19,440,142
2017Y	Tampa Electric Company	Emera Incorporated	119,348	19,425,418
2013Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2014Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2015Y	EL Investment Company, LLC	Entergy Corporation	119,789	31,482,380
2016Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2017Y	EL Investment Company, LLC	Entergy Corporation	NA	NA
2013Y	Entergy Arkansas, Inc.	Entergy Corporation	190,048	29,788,956
2014Y	Entergy Arkansas, Inc.	Entergy Corporation	181,182	31,350,781
2015Y	Entergy Arkansas, Inc.	Entergy Corporation	197,103	31,379,457

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Entergy Arkansas, Inc.	Entergy Corporation	185,467	29,363,790
2017Y	Entergy Arkansas, Inc.	Entergy Corporation	188,114	29,219,532
2013Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	137,996	27,130,595
2014Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	125,366	28,713,874
2015Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	94,552	21,426,698
2016Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA
2017Y	Entergy Gulf States Louisiana, L.L.C.	Entergy Corporation	NA	NA
2013Y	Entergy Louisiana, LLC	Entergy Corporation	169,784	34,156,904
2014Y	Entergy Louisiana, LLC	Entergy Corporation	158,484	37,479,888
2015Y	Entergy Louisiana, LLC	Entergy Corporation	86,301	14,743,976
2016Y	Entergy Louisiana, LLC	Entergy Corporation	284,408	63,634,403
2017Y	Entergy Louisiana, LLC	Entergy Corporation	285,412	61,747,129
2013Y	Entergy Mississippi, Inc.	Entergy Corporation	82,429	14,965,739
2014Y	Entergy Mississippi, Inc.	Entergy Corporation	93,348	16,054,977
2015Y	Entergy Mississippi, Inc.	Entergy Corporation	79,355	14,969,217
2016Y	Entergy Mississippi, Inc.	Entergy Corporation	80,510	14,462,253
2017Y	Entergy Mississippi, Inc.	Entergy Corporation	79,308	13,904,918
2013Y	Entergy New Orleans, LLC	Entergy Corporation	48,573	5,615,573
2014Y	Entergy New Orleans, LLC	Entergy Corporation	42,466	6,570,789
2015Y	Entergy New Orleans, LLC	Entergy Corporation	36,414	7,138,626
2016Y	Entergy New Orleans, LLC	Entergy Corporation	38,691	6,947,771
2017Y	Entergy New Orleans, LLC	Entergy Corporation	36,890	7,327,377
2013Y	Entergy Texas, Inc.	Entergy Corporation	102,265	23,811,698
2014Y	Entergy Texas, Inc.	Entergy Corporation	80,724	22,661,605

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Entergy Texas, Inc.	Entergy Corporation	88,856	23,855,503
2016Y	Entergy Texas, Inc.	Entergy Corporation	80,734	23,892,632
2017Y	Entergy Texas, Inc.	Entergy Corporation	77,937	20,321,420
2013Y	EWO Marketing, LLC	Entergy Corporation	4,085	2,589,069
2014Y	EWO Marketing, LLC	Entergy Corporation	2,149	2,505,358
2015Y	EWO Marketing, LLC	Entergy Corporation	2,706	2,504,139
2016Y	EWO Marketing, LLC	Entergy Corporation	1,541	2,638,560
2017Y	EWO Marketing, LLC	Entergy Corporation	1,374	2,648,461
2013Y	System Energy Resources, Inc.	Entergy Corporation	52,925	9,793,557
2014Y	System Energy Resources, Inc.	Entergy Corporation	37,377	9,218,542
2015Y	System Energy Resources, Inc.	Entergy Corporation	42,894	10,546,906
2016Y	System Energy Resources, Inc.	Entergy Corporation	39,232	5,683,560
2017Y	System Energy Resources, Inc.	Entergy Corporation	40,623	6,675,148
2013Y	Connecticut Light and Power Company	Eversource Energy	221,347	23,299,945
2014Y	Connecticut Light and Power Company	Eversource Energy	182,625	22,647,162
2015Y	Connecticut Light and Power Company	Eversource Energy	192,554	22,643,456
2016Y	Connecticut Light and Power Company	Eversource Energy	183,404	22,342,433
2017Y	Connecticut Light and Power Company	Eversource Energy	183,262	21,611,697
2013Y	NSTAR Electric Company	Eversource Energy	156,881	23,996,935
2014Y	NSTAR Electric Company	Eversource Energy	145,330	23,629,876
2015Y	NSTAR Electric Company	Eversource Energy	158,528	23,856,657
2016Y	NSTAR Electric Company	Eversource Energy	162,571	23,127,763
2017Y	NSTAR Electric Company	Eversource Energy	142,167	21,529,739
2013Y	Public Service Company of New Hampshire	Eversource Energy	108,755	9,118,546

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Public Service Company of New Hampshire	Eversource Energy	95,348	8,595,895
2015Y	Public Service Company of New Hampshire	Eversource Energy	95,309	8,441,532
2016Y	Public Service Company of New Hampshire	Eversource Energy	89,542	8,388,691
2017Y	Public Service Company of New Hampshire	Eversource Energy	87,033	8,116,389
2013Y	Western Massachusetts Electric Company	Eversource Energy	48,971	3,724,299
2014Y	Western Massachusetts Electric Company	Eversource Energy	43,567	3,610,361
2015Y	Western Massachusetts Electric Company	Eversource Energy	40,171	3,601,321
2016Y	Western Massachusetts Electric Company	Eversource Energy	41,313	3,706,255
2017Y	Western Massachusetts Electric Company	Eversource Energy	35,601	3,689,391
2013Y	Atlantic City Electric Company	Exelon Corporation	62,287	11,562,281
2014Y	Atlantic City Electric Company	Exelon Corporation	63,970	11,658,993
2015Y	Atlantic City Electric Company	Exelon Corporation	63,611	11,225,247
2016Y	Atlantic City Electric Company	Exelon Corporation	92,346	10,723,259
2017Y	Atlantic City Electric Company	Exelon Corporation	79,824	9,822,917
2013Y	Baltimore Gas and Electric Company	Exelon Corporation	164,361	30,767,778
2014Y	Baltimore Gas and Electric Company	Exelon Corporation	181,561	30,562,078
2015Y	Baltimore Gas and Electric Company	Exelon Corporation	190,837	30,304,293
2016Y	Baltimore Gas and Electric Company	Exelon Corporation	190,297	30,019,586
2017Y	Baltimore Gas and Electric Company	Exelon Corporation	193,448	28,970,770
2013Y	Commonwealth Edison Company	Exelon Corporation	504,290	93,089,440
2014Y	Commonwealth Edison Company	Exelon Corporation	426,075	90,578,581
2015Y	Commonwealth Edison Company	Exelon Corporation	458,371	87,297,520
2016Y	Commonwealth Edison Company	Exelon Corporation	488,644	89,608,490
2017Y	Commonwealth Edison Company	Exelon Corporation	470,618	87,568,519

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Delmarva Power & Light Company	Exelon Corporation	69,461	12,817,180
2014Y	Delmarva Power & Light Company	Exelon Corporation	64,650	12,782,957
2015Y	Delmarva Power & Light Company	Exelon Corporation	69,386	12,805,844
2016Y	Delmarva Power & Light Company	Exelon Corporation	100,113	12,486,406
2017Y	Delmarva Power & Light Company	Exelon Corporation	88,600	12,222,536
2013Y	PECO Energy Company	Exelon Corporation	170,320	38,044,130
2014Y	PECO Energy Company	Exelon Corporation	168,781	37,681,485
2015Y	PECO Energy Company	Exelon Corporation	173,274	38,124,845
2016Y	PECO Energy Company	Exelon Corporation	187,942	37,940,620
2017Y	PECO Energy Company	Exelon Corporation	192,458	37,233,657
2013Y	Potomac Electric Power Company	Exelon Corporation	139,967	25,807,813
2014Y	Potomac Electric Power Company	Exelon Corporation	132,079	25,750,549
2015Y	Potomac Electric Power Company	Exelon Corporation	134,609	25,987,432
2016Y	Potomac Electric Power Company	Exelon Corporation	183,061	26,114,290
2017Y	Potomac Electric Power Company	Exelon Corporation	156,730	24,855,893
2013Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	-1,743	18,712,244
2014Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	68,702	18,733,302
2015Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	24,691	18,501,986
2016Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	79,371	18,817,928
2017Y	Cleveland Electric Illuminating Company	FirstEnergy Corp.	58,920	18,290,574
2013Y	Jersey Central Power & Light Company	FirstEnergy Corp.	12,105	21,836,806
2014Y	Jersey Central Power & Light Company	FirstEnergy Corp.	156,696	21,846,258
2015Y	Jersey Central Power & Light Company	FirstEnergy Corp.	92,158	21,332,986
2016Y	Jersey Central Power & Light Company	FirstEnergy Corp.	111,549	21,250,880

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Jersey Central Power & Light Company	FirstEnergy Corp.	112,628	20,535,764
2013Y	Metropolitan Edison Company	FirstEnergy Corp.	1,357	14,226,643
2014Y	Metropolitan Edison Company	FirstEnergy Corp.	75,295	14,276,774
2015Y	Metropolitan Edison Company	FirstEnergy Corp.	49,373	14,291,940
2016Y	Metropolitan Edison Company	FirstEnergy Corp.	58,329	14,143,059
2017Y	Metropolitan Edison Company	FirstEnergy Corp.	48,959	13,777,426
2013Y	Monongahela Power Company	FirstEnergy Corp.	3,568	10,816,852
2014Y	Monongahela Power Company	FirstEnergy Corp.	103,251	17,361,198
2015Y	Monongahela Power Company	FirstEnergy Corp.	49,864	16,163,874
2016Y	Monongahela Power Company	FirstEnergy Corp.	45,148	17,434,322
2017Y	Monongahela Power Company	FirstEnergy Corp.	88,527	17,497,075
2013Y	Ohio Edison Company	FirstEnergy Corp.	-17,423	27,059,942
2014Y	Ohio Edison Company	FirstEnergy Corp.	117,580	27,819,394
2015Y	Ohio Edison Company	FirstEnergy Corp.	70,226	27,056,153
2016Y	Ohio Edison Company	FirstEnergy Corp.	99,745	26,451,421
2017Y	Ohio Edison Company	FirstEnergy Corp.	74,961	23,977,058
2013Y	Pennsylvania Electric Company	FirstEnergy Corp.	-3,745	15,484,578
2014Y	Pennsylvania Electric Company	FirstEnergy Corp.	82,436	14,771,582
2015Y	Pennsylvania Electric Company	FirstEnergy Corp.	57,647	14,473,442
2016Y	Pennsylvania Electric Company	FirstEnergy Corp.	60,926	14,386,263
2017Y	Pennsylvania Electric Company	FirstEnergy Corp.	48,742	14,363,454
2013Y	Pennsylvania Power Company	FirstEnergy Corp.	-2,351	4,567,609
2014Y	Pennsylvania Power Company	FirstEnergy Corp.	20,237	4,714,488
2015Y	Pennsylvania Power Company	FirstEnergy Corp.	13,033	4,526,159

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Pennsylvania Power Company	FirstEnergy Corp.	16,950	4,615,081
2017Y	Pennsylvania Power Company	FirstEnergy Corp.	15,467	4,633,922
2013Y	Potomac Edison Company	FirstEnergy Corp.	8,558	11,862,840
2014Y	Potomac Edison Company	FirstEnergy Corp.	43,830	11,898,341
2015Y	Potomac Edison Company	FirstEnergy Corp.	22,303	11,823,082
2016Y	Potomac Edison Company	FirstEnergy Corp.	26,469	11,554,451
2017Y	Potomac Edison Company	FirstEnergy Corp.	30,899	11,322,812
2013Y	Toledo Edison Company	FirstEnergy Corp.	3,625	11,956,365
2014Y	Toledo Edison Company	FirstEnergy Corp.	46,524	11,873,197
2015Y	Toledo Edison Company	FirstEnergy Corp.	19,874	11,779,382
2016Y	Toledo Edison Company	FirstEnergy Corp.	34,416	12,079,562
2017Y	Toledo Edison Company	FirstEnergy Corp.	24,262	10,856,745
2013Y	West Penn Power Company	FirstEnergy Corp.	27,122	20,052,177
2014Y	West Penn Power Company	FirstEnergy Corp.	91,601	20,291,236
2015Y	West Penn Power Company	FirstEnergy Corp.	50,621	20,083,013
2016Y	West Penn Power Company	FirstEnergy Corp.	58,699	19,998,876
2017Y	West Penn Power Company	FirstEnergy Corp.	63,625	19,616,843
2013Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	86,177	2,761,676
2014Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	82,731	2,623,309
2015Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	68,770	2,608,207
2016Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	68,939	2,684,357
2017Y	Central Hudson Gas & Electric Corporation	Fortis Inc.	70,713	2,602,989
2013Y	Tucson Electric Power Company	Fortis Inc.	93,257	13,025,375
2014Y	Tucson Electric Power Company	Fortis Inc.	102,590	13,311,011

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Tucson Electric Power Company	Fortis Inc.	106,428	14,279,396
2016Y	Tucson Electric Power Company	Fortis Inc.	111,249	13,718,397
2017Y	Tucson Electric Power Company	Fortis Inc.	115,191	13,442,595
2013Y	UNS Electric, Inc.	Fortis Inc.	11,529	2,230,041
2014Y	UNS Electric, Inc.	Fortis Inc.	9,469	1,982,714
2015Y	UNS Electric, Inc.	Fortis Inc.	9,472	1,746,289
2016Y	UNS Electric, Inc.	Fortis Inc.	11,116	1,762,853
2017Y	UNS Electric, Inc.	Fortis Inc.	10,205	1,916,799
2013Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	155,758	21,683,329
2014Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	161,898	22,472,307
2015Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	160,805	20,796,733
2016Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	168,097	21,433,876
2017Y	Kansas City Power & Light Company	Great Plains Energy Incorporated	156,680	21,322,723
2013Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	74,537	8,413,828
2014Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	74,615	8,511,766
2015Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	79,679	8,385,574
2016Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	81,446	8,465,650
2017Y	KCP&L Greater Missouri Operations Company	Great Plains Energy Incorporated	85,028	8,386,821
2013Y	Central Maine Power Company	Iberdrola, S.A.	49,541	603,824
2014Y	Central Maine Power Company	Iberdrola, S.A.	60,889	590,204
2015Y	Central Maine Power Company	Iberdrola, S.A.	66,961	600,705
2016Y	Central Maine Power Company	Iberdrola, S.A.	55,417	599,743
2017Y	Central Maine Power Company	Iberdrola, S.A.	46,507	172,595
2013Y	Maine Electric Power Company, Inc.	Iberdrola, S.A.	99	NA

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Maine Electric Power Company, Inc.	Iberdrola, S.A.	167	NA
2015Y	Maine Electric Power Company, Inc.	Iberdrola, S.A.	241	NA
2016Y	Maine Electric Power Company, Inc.	Iberdrola, S.A.	329	NA
2017Y	Maine Electric Power Company, Inc.	Iberdrola, S.A.	342	NA
2013Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	118,188	19,115,201
2014Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	115,355	18,690,994
2015Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	111,757	17,887,199
2016Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	96,599	17,455,920
2017Y	New York State Electric & Gas Corporation	Iberdrola, S.A.	88,542	16,633,428
2013Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	72,913	9,024,632
2014Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	55,068	7,970,527
2015Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	54,907	7,319,681
2016Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	40,803	7,365,999
2017Y	Rochester Gas and Electric Corporation	Iberdrola, S.A.	39,870	7,216,272
2013Y	United Illuminating Company	Iberdrola, S.A.	49,291	5,422,427
2014Y	United Illuminating Company	Iberdrola, S.A.	32,927	5,327,395
2015Y	United Illuminating Company	Iberdrola, S.A.	65,125	5,450,238
2016Y	United Illuminating Company	Iberdrola, S.A.	31,949	5,334,351
2017Y	United Illuminating Company	Iberdrola, S.A.	25,249	5,093,904
2013Y	Idaho Power Co.	IDACORP, Inc.	151,020	16,302,681
2014Y	Idaho Power Co.	IDACORP, Inc.	155,933	16,312,786
2015Y	Idaho Power Co.	IDACORP, Inc.	140,370	15,518,629
2016Y	Idaho Power Co.	IDACORP, Inc.	146,887	15,381,629
2017Y	Idaho Power Co.	IDACORP, Inc.	142,691	16,706,603

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Kentucky Utilities Company	LKE	111,709	21,629,993
2014Y	Kentucky Utilities Company	LKE	99,819	21,986,858
2015Y	Kentucky Utilities Company	LKE	117,399	21,810,131
2016Y	Kentucky Utilities Company	LKE	108,557	21,437,963
2017Y	Kentucky Utilities Company	LKE	109,507	20,497,797
2013Y	Louisville Gas and Electric Company	LKE	84,240	14,478,316
2014Y	Louisville Gas and Electric Company	LKE	79,526	15,373,731
2015Y	Louisville Gas and Electric Company	LKE	81,077	13,502,213
2016Y	Louisville Gas and Electric Company	LKE	79,109	13,156,493
2017Y	Louisville Gas and Electric Company	LKE	76,486	13,133,134
2013Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	20,293	3,195,882
2014Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	20,256	3,331,202
2015Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	21,966	3,316,058
2016Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	24,873	3,303,555
2017Y	MDU Resources Group, Inc.	MDU Resources Group, Inc.	26,686	3,346,441
2013Y	Madison Gas and Electric Company	MGE Energy, Inc.	38,732	3,557,446
2014Y	Madison Gas and Electric Company	MGE Energy, Inc.	32,876	3,514,574
2015Y	Madison Gas and Electric Company	MGE Energy, Inc.	34,373	3,545,081
2016Y	Madison Gas and Electric Company	MGE Energy, Inc.	34,540	3,741,999
2017Y	Madison Gas and Electric Company	MGE Energy, Inc.	33,811	3,584,998
2013Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	3,130	99,446
2014Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	3,200	99,841
2015Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	2,727	99,902
2016Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	2,513	95,751

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Mt. Carmel Public Utility Company	Mt. Carmel Public Utility Company	2,829	95,101
2013Y	Massachusetts Electric Company	National Grid plc	228,950	11,080,137
2014Y	Massachusetts Electric Company	National Grid plc	266,932	10,608,963
2015Y	Massachusetts Electric Company	National Grid plc	273,313	8,699,117
2016Y	Massachusetts Electric Company	National Grid plc	294,710	6,486,573
2017Y	Massachusetts Electric Company	National Grid plc	289,485	6,427,679
2013Y	Narragansett Electric Company	National Grid plc	85,931	5,133,864
2014Y	Narragansett Electric Company	National Grid plc	89,338	5,006,934
2015Y	Narragansett Electric Company	National Grid plc	90,146	4,492,267
2016Y	Narragansett Electric Company	National Grid plc	106,125	3,954,763
2017Y	Narragansett Electric Company	National Grid plc	118,556	3,868,162
2013Y	National Grid Generation, LLC	National Grid plc	66,239	4,823,499
2014Y	National Grid Generation, LLC	National Grid plc	68,310	4,558,386
2015Y	National Grid Generation, LLC	National Grid plc	70,258	5,050,928
2016Y	National Grid Generation, LLC	National Grid plc	71,798	4,561,590
2017Y	National Grid Generation, LLC	National Grid plc	61,006	3,213,471
2013Y	New England Power Company	National Grid plc	36,234	570,917
2014Y	New England Power Company	National Grid plc	52,570	565,418
2015Y	New England Power Company	National Grid plc	50,321	566,430
2016Y	New England Power Company	National Grid plc	49,527	314,990
2017Y	New England Power Company	National Grid plc	53,721	239,434
2013Y	Niagara Mohawk Power Corporation	National Grid plc	479,781	16,348,792
2014Y	Niagara Mohawk Power Corporation	National Grid plc	397,932	13,620,478
2015Y	Niagara Mohawk Power Corporation	National Grid plc	365,359	13,464,032

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Niagara Mohawk Power Corporation	National Grid plc	370,611	13,600,814
2017Y	Niagara Mohawk Power Corporation	National Grid plc	371,233	13,190,657
2013Y	Florida Power & Light Company	NextEra Energy, Inc.	407,062	107,373,794
2014Y	Florida Power & Light Company	NextEra Energy, Inc.	354,091	112,929,729
2015Y	Florida Power & Light Company	NextEra Energy, Inc.	347,310	119,405,262
2016Y	Florida Power & Light Company	NextEra Energy, Inc.	335,632	119,279,691
2017Y	Florida Power & Light Company	NextEra Energy, Inc.	443,699	117,873,183
2013Y	Northern Indiana Public Service Company	NiSource Inc.	183,441	17,468,011
2014Y	Northern Indiana Public Service Company	NiSource Inc.	202,804	18,186,288
2015Y	Northern Indiana Public Service Company	NiSource Inc.	211,596	16,758,427
2016Y	Northern Indiana Public Service Company	NiSource Inc.	220,923	16,831,194
2017Y	Northern Indiana Public Service Company	NiSource Inc.	221,425	16,725,564
2013Y	NorthWestern Corporation	NorthWestern Corporation	64,655	9,519,519
2014Y	NorthWestern Corporation	NorthWestern Corporation	64,785	10,006,908
2015Y	NorthWestern Corporation	NorthWestern Corporation	76,796	11,027,880
2016Y	NorthWestern Corporation	NorthWestern Corporation	78,502	9,037,846
2017Y	NorthWestern Corporation	NorthWestern Corporation	82,653	8,924,244
2013Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	111,759	28,578,159
2014Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	118,327	30,234,927
2015Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	133,349	28,867,056
2016Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	141,320	29,762,475
2017Y	Oklahoma Gas and Electric Company	OGE Energy Corp.	137,559	28,111,471
2013Y	Otter Tail Power Company	Otter Tail Corporation	39,523	6,219,751
2014Y	Otter Tail Power Company	Otter Tail Corporation	41,787	5,470,896

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Otter Tail Power Company	Otter Tail Corporation	42,025	4,709,464
2016Y	Otter Tail Power Company	Otter Tail Corporation	44,695	4,955,630
2017Y	Otter Tail Power Company	Otter Tail Corporation	45,577	5,040,591
2013Y	Pacific Gas and Electric Company	PG&E Corporation	978,665	88,322,913
2014Y	Pacific Gas and Electric Company	PG&E Corporation	1,018,104	88,189,685
2015Y	Pacific Gas and Electric Company	PG&E Corporation	1,052,736	87,981,023
2016Y	Pacific Gas and Electric Company	PG&E Corporation	1,329,265	85,067,412
2017Y	Pacific Gas and Electric Company	PG&E Corporation	1,178,530	88,175,650
2013Y	Arizona Public Service Company	Pinnacle West Capital Corporation	213,793	32,087,545
2014Y	Arizona Public Service Company	Pinnacle West Capital Corporation	192,118	32,951,388
2015Y	Arizona Public Service Company	Pinnacle West Capital Corporation	167,749	33,628,854
2016Y	Arizona Public Service Company	Pinnacle West Capital Corporation	186,773	31,928,046
2017Y	Arizona Public Service Company	Pinnacle West Capital Corporation	183,317	30,910,170
2013Y	Public Service Company of New Mexico	PNM Resources, Inc.	135,149	12,001,980
2014Y	Public Service Company of New Mexico	PNM Resources, Inc.	131,296	11,836,387
2015Y	Public Service Company of New Mexico	PNM Resources, Inc.	140,392	11,541,512
2016Y	Public Service Company of New Mexico	PNM Resources, Inc.	149,173	12,280,191
2017Y	Public Service Company of New Mexico	PNM Resources, Inc.	151,950	12,454,143
2013Y	Portland General Electric Company	Portland General Electric Company	157,719	21,226,863
2014Y	Portland General Electric Company	Portland General Electric Company	161,772	21,080,082
2015Y	Portland General Electric Company	Portland General Electric Company	171,798	20,859,230
2016Y	Portland General Electric Company	Portland General Electric Company	176,471	21,247,271
2017Y	Portland General Electric Company	Portland General Electric Company	190,763	21,328,945
2013Y	PPL Electric Utilities Corporation	PPL Corporation	155,674	37,712,878

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	PPL Electric Utilities Corporation	PPL Corporation	151,567	38,005,667
2015Y	PPL Electric Utilities Corporation	PPL Corporation	194,342	37,967,738
2016Y	PPL Electric Utilities Corporation	PPL Corporation	201,744	37,618,811
2017Y	PPL Electric Utilities Corporation	PPL Corporation	188,465	36,939,991
2013Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	198,397	44,103,026
2014Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	156,848	42,728,622
2015Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	200,581	43,533,905
2016Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	192,577	42,288,312
2017Y	Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	201,932	40,894,038
2013Y	Puget Sound Energy, Inc.	Puget Holdings LLC	109,153	26,265,216
2014Y	Puget Sound Energy, Inc.	Puget Holdings LLC	108,863	21,968,767
2015Y	Puget Sound Energy, Inc.	Puget Holdings LLC	110,378	28,183,148
2016Y	Puget Sound Energy, Inc.	Puget Holdings LLC	120,326	29,143,765
2017Y	Puget Sound Energy, Inc.	Puget Holdings LLC	128,643	27,227,367
2013Y	South Carolina Electric & Gas Co.	SCANA Corporation	163,369	22,326,578
2014Y	South Carolina Electric & Gas Co.	SCANA Corporation	169,415	23,332,942
2015Y	South Carolina Electric & Gas Co.	SCANA Corporation	166,943	23,114,845
2016Y	South Carolina Electric & Gas Co.	SCANA Corporation	191,727	23,471,194
2017Y	South Carolina Electric & Gas Co.	SCANA Corporation	166,141	22,879,069
2013Y	South Carolina Generating Company, Inc.	SCANA Corporation	5,546	3,343,690
2014Y	South Carolina Generating Company, Inc.	SCANA Corporation	5,549	3,702,495
2015Y	South Carolina Generating Company, Inc.	SCANA Corporation	5,599	3,734,928
2016Y	South Carolina Generating Company, Inc.	SCANA Corporation	5,858	2,991,906
2017Y	South Carolina Generating Company, Inc.	SCANA Corporation	4,998	2,606,561

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Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2013Y	Oncor Electric Delivery Company LLC	Sempra Energy	344,543	112,312,279
2014Y	Oncor Electric Delivery Company LLC	Sempra Energy	351,557	114,905,829
2015Y	Oncor Electric Delivery Company LLC	Sempra Energy	357,751	116,594,625
2016Y	Oncor Electric Delivery Company LLC	Sempra Energy	359,066	115,791,379
2017Y	Oncor Electric Delivery Company LLC	Sempra Energy	376,080	117,017,075
2013Y	San Diego Gas & Electric Co.	Sempra Energy	628,738	32,916,382
2014Y	San Diego Gas & Electric Co.	Sempra Energy	590,458	30,952,957
2015Y	San Diego Gas & Electric Co.	Sempra Energy	455,443	33,132,033
2016Y	San Diego Gas & Electric Co.	Sempra Energy	400,172	29,443,890
2017Y	San Diego Gas & Electric Co.	Sempra Energy	425,629	29,300,970
2013Y	Alabama Power Company	Southern Company	351,531	66,309,626
2014Y	Alabama Power Company	Southern Company	360,311	67,155,314
2015Y	Alabama Power Company	Southern Company	413,430	63,847,336
2016Y	Alabama Power Company	Southern Company	387,122	63,873,423
2017Y	Alabama Power Company	Southern Company	426,571	63,290,561
2013Y	Georgia Power Company	Southern Company	445,491	84,726,779
2014Y	Georgia Power Company	Southern Company	448,174	89,190,865
2015Y	Georgia Power Company	Southern Company	463,892	87,859,128
2016Y	Georgia Power Company	Southern Company	472,842	89,686,468
2017Y	Georgia Power Company	Southern Company	410,706	86,478,222
2013Y	Gulf Power Company	Southern Company	80,099	14,909,545
2014Y	Gulf Power Company	Southern Company	81,740	16,028,868
2015Y	Gulf Power Company	Southern Company	91,589	14,031,937
2016Y	Gulf Power Company	Southern Company	85,198	14,616,769

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2017Y	Gulf Power Company	Southern Company	92,689	15,445,454
2013Y	Mississippi Power Company	Southern Company	83,327	14,591,834
2014Y	Mississippi Power Company	Southern Company	88,045	17,059,643
2015Y	Mississippi Power Company	Southern Company	95,356	16,487,788
2016Y	Mississippi Power Company	Southern Company	100,982	14,866,485
2017Y	Mississippi Power Company	Southern Company	87,559	15,283,882
2013Y	Southern Electric Generating Company	Southern Company	8,815	2,107,334
2014Y	Southern Electric Generating Company	Southern Company	8,003	2,084,739
2015Y	Southern Electric Generating Company	Southern Company	7,073	1,277,061
2016Y	Southern Electric Generating Company	Southern Company	6,022	394,540
2017Y	Southern Electric Generating Company	Southern Company	5,032	1,406,811
2013Y	UGI Utilities, Inc.	UGI Corporation	6,228	1,000,701
2014Y	UGI Utilities, Inc.	UGI Corporation	7,295	975,771
2015Y	UGI Utilities, Inc.	UGI Corporation	8,848	990,384
2016Y	UGI Utilities, Inc.	UGI Corporation	5,745	977,118
2017Y	UGI Utilities, Inc.	UGI Corporation	8,538	956,654
2013Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	4,960	505,418
2014Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	5,455	533,929
2015Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	5,397	460,811
2016Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	5,546	444,498
2017Y	Fitchburg Gas and Electric Light Company	Unitil Corporation	5,928	455,496
2013Y	Unitil Energy Systems, Inc.	Unitil Corporation	8,527	1,234,354
2014Y	Unitil Energy Systems, Inc.	Unitil Corporation	8,508	1,230,055
2015Y	Unitil Energy Systems, Inc.	Unitil Corporation	9,125	1,229,879

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

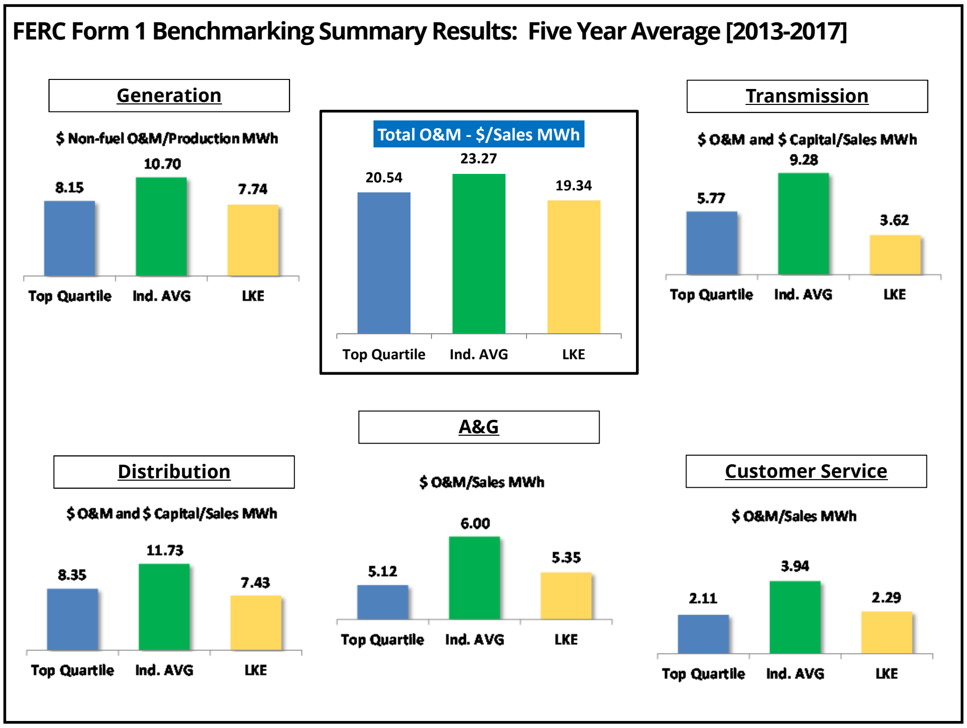
Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2016Y	Unitil Energy Systems, Inc.	Unitil Corporation	9,606	1,203,404
2017Y	Unitil Energy Systems, Inc.	Unitil Corporation	9,992	1,215,797
2013Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	39,735	5,993,477
2014Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	39,876	6,240,584
2015Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	36,736	5,795,918
2016Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	38,839	5,610,259
2017Y	Southern Indiana Gas and Electric Company, Inc.	Vectren Corporation	42,948	5,220,819
2013Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	193,856	32,555,334
2014Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	165,748	32,942,828
2015Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	144,780	35,818,700
2016Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	134,459	35,894,209
2017Y	Wisconsin Electric Power Company	WEC Energy Group, Inc.	130,505	34,951,750
2013Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	92,912	16,129,893
2014Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	74,336	14,557,949
2015Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	81,249	14,839,077
2016Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	115,635	14,636,889
2017Y	Wisconsin Public Service Corporation	WEC Energy Group, Inc.	76,869	14,814,995
2013Y	Kansas Gas and Electric Company	Westar Energy, Inc.	103,866	10,605,055
2014Y	Kansas Gas and Electric Company	Westar Energy, Inc.	99,352	10,800,465
2015Y	Kansas Gas and Electric Company	Westar Energy, Inc.	106,387	10,761,626
2016Y	Kansas Gas and Electric Company	Westar Energy, Inc.	102,900	11,297,034
2017Y	Kansas Gas and Electric Company	Westar Energy, Inc.	99,142	10,847,878
2013Y	Westar Energy (KPL)	Westar Energy, Inc.	97,746	17,484,374
2014Y	Westar Energy (KPL)	Westar Energy, Inc.	107,569	18,531,716

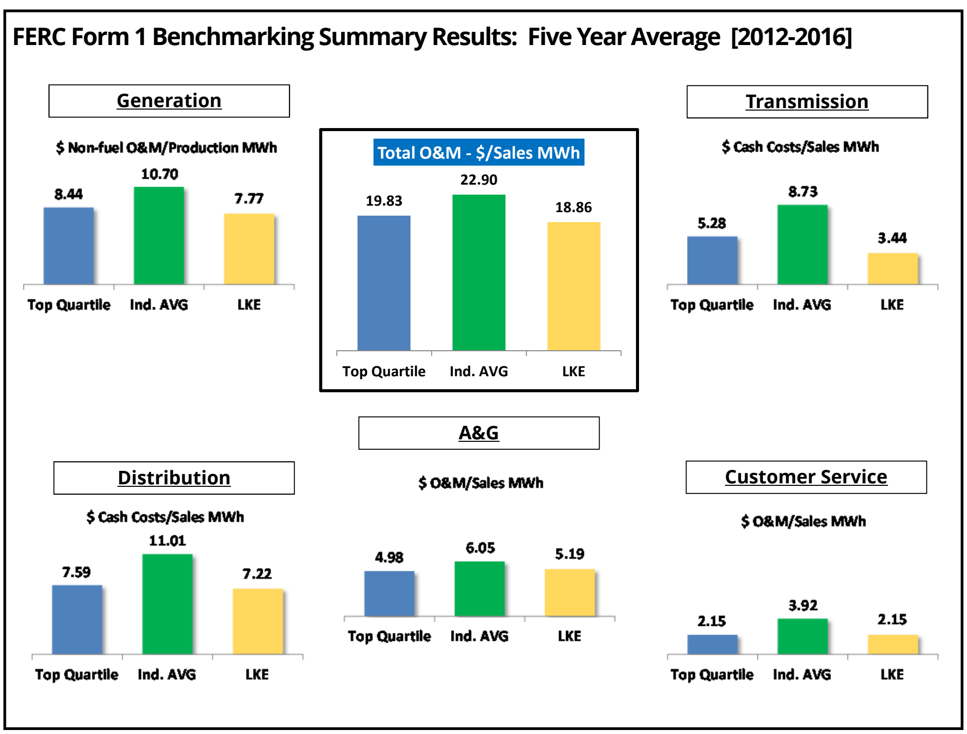
Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2015Y	Westar Energy (KPL)	Westar Energy, Inc.	114,098	17,180,535
2016Y	Westar Energy (KPL)	Westar Energy, Inc.	107,220	16,555,817
2017Y	Westar Energy (KPL)	Westar Energy, Inc.	100,252	18,790,662
2013Y	Westar Generating, Inc.	Westar Energy, Inc.	992	735,166
2014Y	Westar Generating, Inc.	Westar Energy, Inc.	994	608,351
2015Y	Westar Generating, Inc.	Westar Energy, Inc.	1,259	690,492
2016Y	Westar Generating, Inc.	Westar Energy, Inc.	878	945,870
2017Y	Westar Generating, Inc.	Westar Energy, Inc.	940	983,635
2013Y	Wisconsin River Power Company	Wisconsin River Power Company	1,348	20
2014Y	Wisconsin River Power Company	Wisconsin River Power Company	1,342	222,969
2015Y	Wisconsin River Power Company	Wisconsin River Power Company	1,289	204,110
2016Y	Wisconsin River Power Company	Wisconsin River Power Company	1,120	248,314
2017Y	Wisconsin River Power Company	Wisconsin River Power Company	1,038	44,527
2013Y	Northern States Power Company - MN	Xcel Energy Inc.	254,713	37,474,524
2014Y	Northern States Power Company - MN	Xcel Energy Inc.	257,214	39,129,144
2015Y	Northern States Power Company - MN	Xcel Energy Inc.	263,079	39,484,126
2016Y	Northern States Power Company - MN	Xcel Energy Inc.	265,532	41,519,021
2017Y	Northern States Power Company - MN	Xcel Energy Inc.	269,990	40,720,489
2013Y	Northern States Power Company - WI	Xcel Energy Inc.	41,603	6,562,368
2014Y	Northern States Power Company - WI	Xcel Energy Inc.	41,794	6,750,889
2015Y	Northern States Power Company - WI	Xcel Energy Inc.	44,911	6,647,300
2016Y	Northern States Power Company - WI	Xcel Energy Inc.	41,367	6,641,542
2017Y	Northern States Power Company - WI	Xcel Energy Inc.	44,065	6,727,740
2013Y	Public Service Company of Colorado	Xcel Energy Inc.	167,001	33,450,187

Notes: NA data generally represents a merger with another operating company within the same parent/holding company.
Certain LKE adjustments were made to reclass labor and IT software costs from A&G to lines of business.

Year	Company Name	Ultimate Parent Company Name	Total Adminstrative & General O&M Expense ($000)	Total Sales of Electricity Volume (MWh)
2014Y	Public Service Company of Colorado	Xcel Energy Inc.	163,014	32,498,488
2015Y	Public Service Company of Colorado	Xcel Energy Inc.	166,379	32,396,474
2016Y	Public Service Company of Colorado	Xcel Energy Inc.	165,928	34,472,722
2017Y	Public Service Company of Colorado	Xcel Energy Inc.	177,229	36,486,396
2013Y	Southwestern Public Service Company	Xcel Energy Inc.	96,828	28,292,788
2014Y	Southwestern Public Service Company	Xcel Energy Inc.	100,214	28,265,391
2015Y	Southwestern Public Service Company	Xcel Energy Inc.	107,892	28,414,831
2016Y	Southwestern Public Service Company	Xcel Energy Inc.	101,761	28,383,129
2017Y	Southwestern Public Service Company	Xcel Energy Inc.	105,746	27,124,064
		Total	89,285,764	14,881,658,340


FERC Form 1 Benchmarking Summary Results: Five Year Average [2013-2017]
Generation
$ Non-fuel O&M/Production MWh
8.15
10.70
7.74
Top Quartile
Ind. AVG
LKE
Total O&M - $/Sales MWh
20.54
23.27
19.34
Top Quartile
Ind. AVG
LKE
Transmission
$ O&M and $ Capital/Sales MWh
5.77
9.28
3.62
Top Quartile
Ind. AVG
LKE
A&G
$ O&M/Sales MWh
5.12
6.00
5.35
Top Quartile
Ind. AVG
LKE
Distribution
$ O&M and $ Capital/Sales MWh
8.35
11.73
7.43
Top Quartile
Ind. AVG
LKE
Customer Service
$ O&M/Sales MWh
2.11
3.94
2.29
Top Quartile
Ind. AVG
LKE


FERC Form 1 Benchmarking Summary Results: Five Year Average [2012-2016]
Generation
$ Non-fuel O&M/Production MWh
8.44
10.70
7.77
Top Quartile
Ind. AVG
LKE
Total O&M - $/Sales MWh
19.83
22.90
18.86
Top Quartile
Ind. AVG
LKE
Transmission
$ Cash Costs/Sales MWh
5.28
8.73
3.44
Top Quartile
Ind. AVG
LKE
A&G
$ O&M/Sales MWh
4.98
6.05
5.19
Top Quartile
Ind. AVG
LKE
Distribution
$ Cash Costs/Sales MWh
7.59
11.01
7.22
Top Quartile
Ind. AVG
LKE
Customer Service
$ O&M/Sales MWh
2.15
3.92
2.15
Top Quartile
Ind. AVG
LKE

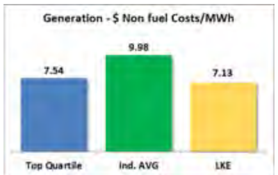
FERC Form 1 Benchmarking Summary Results: Five Year Average [2011-2015]

FERC Form 1 Benchmarking Summary Results: Five Year Average [2010-2014]

Key Observations:

- LKE outperforms industry averages in all five cost segments.
- Spending in Cust. Services & Distribution reflects additional investment in customer service and reliability to meet customer needs and regulatory expectations.

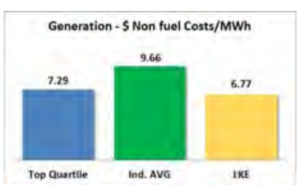
FERC Form 1 Benchmarking Summary Results: Five Year Average [2009-2013]



Key Observations:

- LKE outperforms industry averages in all five cost segments.
- LKE ranks in the top quartile in three of five cost segments.
- Spending in Customer Services and Distribution reflects additional investment in customer service and reliability to meet customer needs and regulatory expectations.

FERC Form 1 Benchmarking Summary Results: Five Year Average [2008-2012]



Key observations:

- LKE outperforms industry averages in all five cost segments.
- LKE ranks in the top quartile in three of five cost segments.
- LKE continues to be a solid top quartile performer in Generation, Transmission, and A&G.
- Spending in Retail and Distribution reflects additional investment in customer service and reliability to meet customer needs and regulatory expectations.

FERC Form 1 Benchmarking Summary Results: Five Year Average [2007-2011]

Utility Area	Metric Description	Metric	LKE Ranking	Last Year's Results (2006 - 2010)	
Generation	Non fuel O&M/MWH of Production	$6.18	5th - top quartile	$5.71	5th - top quartile
Transmission	Cash Cost/Transmission Mile	$18,630	7th - top quartile	$16,491	7th - top quartile
Distribution	Cash Cost/Customer	$237.18	28th - second quartile	$218.79	24th -second quartile
Retail	O&M Cost/Customer	$57.93	15th - top quartile	$52.44	16th - top quartile
Corporate A&G	A&G Cost/MWH of Sales	$3.87	8th - top quartile	$3.57	8th - top quartile

FERC Form 1 Benchmarking Summary Results: Five Year Average [2006–2010]

Utility Area	Metric Description	Metric	LKE Ranking	Last Year's Results [2005 – 2009]	
Generation	Non fuel O&M/MWH of Production	$5.71	5th - Top Quartile	$5.22	5th - Top Quartile
Transmission	Cash Cost/Transmission Mile	$16,491	7th - Top Quartile	$11,549	7th - Top Quartile
Distribution	Cash Cost/Customer	$218.79	24th - Second Quartile	$199.25	16th - Top Quartile
Retail	O&M Cost/Customer	$52.44	16th - Top Quartile	$46.74	16th - Top Quartile
Corporate A&G	A&G Cost/MWH of Sales	$3.57	8th - Top Quartile	$3.39	8th - Top Quartile

FERC Form 1 Benchmarking Summary Results: Five Year Average [2005-2009]

Utility Area	Metric Description	Metric	E.ON U.S. Ranking	Last Year's Results (2004 - 2008)	
Generation	Non fuel O&M/MWH of Production	$5.22	5th - Top Decile	$4.78	4th - Top Decile
Transmission	Cash Cost/Transmission Mile	$11,549	7th - Top Quartile	$10,702	6th - Top Decile
Distribution	Cash Cost/Customer	$199.25	16th - Top Quartile	$189	16th - Top Quartile
Retail	O&M Cost/Customer	$46.74	16th -Top Quartile	$41.51	11th - Top Quartile
Corporate A&G	A&G Cost/MWH of Sales	$3.39	8th - Top Quartile	$3.23	7th - Top Decile

FERC Form 1 Benchmarking Summary Results: Five Year Average [2004-2008]

Utility Area	Metric/E.ON U.S. Performance		E.ON U.S Rank Out of Holding Companies
Generation	Non-fuel O&M/ MWh of Production	$4.78	4th —Top Decile
Transmission	Cash Cost/ Transmission Mile	$10,702	6th — Top Decile
Distribution	Cash Cost/ Customer	$189[1]	16th — Top Quartile
Retail	O&M Cost/ Customer	$41.51	11th — Second Decile
Corporate A&G	A&G Cost/ MWh of Sales	$3.23[2]	7th — Top Decile

[1]If E.ON U.S. is not adjusted for CWIP changes over the five year period, our ranking is 8th at $173.
[2]If adjusted for $80m of VDT amortization costs over the five year period, our ranking improves to 5th at $2.86.

FERC Form 1 Benchmarking Summary Results: Five Year Average [2003-2007]

Utility Area	Metric/E.ON U.S. Performance		E.ON U.S Rank Out of Holding Companies
Generation	Non-fuel O&M/ MWh of Production	$4.50	2nd —Top Decile
Transmission	Cash Cost/ Transmission Mile	$11,439	10th — Second Decile
Distribution	Cash Cost/ Customer	$180[1]	15th — Top Quartile
Retail	O&M Cost/ Customer	$41.69	13th — Second Decile
Corporate A&G	A&G Cost/ MWh of Sales	$3.35[2]	9th — Second Decile

[1]If E.ON U.S. is not adjusted for capital additions (CWIP) over the five year period, our ranking is 1st at $135.
[2]If adjusted for $116m of VDT amortization costs over the five year period, our ranking increases to 6th at $2.81.

FERC Form 1 Benchmarking Summary Results: Four Year Average [2003-2006]

Utility Area	Metric/E.ON U.S. Performance		E.ON U.S Rank Out of IOU Holding Companies
Generation	Non-fuel O&M/ MWh of Production	$4.37	4th —Top Decile
Transmission	Cash Cost/ Transmission Mile	$11,230	13th — Second Decile
Distribution	Cash Cost/ Customer	$140	2nd — Top Decile
Retail	O&M Cost/ Customer	$41.29	13th — Second Decile
Corporate A&G[1]	A&G Cost/ MWh of Sales	$3.44	12th — Second Decile

[1]If adjusted for $116m of VDT amortization costs over the four year period, our ranking increases to 7th at $2.77.

FERC Form 1 Benchmarking Summary Results: Four Year Average [2002-2005]

Utility Area	Metric/E.ON U.S. Performance		E.ON U.S Rank Out of IOU Holding Companies
Generation	Non-fuel O&M/ MWh of Production	$4.27	4th —Top Decile
Transmission	Cash Cost/ Transmission Mile	$12,508	19th — Third Decile
Distribution[1]	Cash Cost/ Customer	$141	5th — Top Decile
Retail[2]	O&M Cost/ Customer	$42.10	15th — Top Quartile
Corporate A&G[3]	A&G Cost/ MWh of Sales	$2.72	6th — Top Decile

[1] E.ON U.S. adjusted +$6.0M for FERC account coding reclassifications
[2] E.ON U.S. adjusted +$8M for FERC account coding reclassifications
[3] E.ON U.S. adjusted -$143M of VDT amortization costs and -$14M FERC account coding reclassifications

FERC Form 1 Benchmarking Summary Results: Four Year Average [2001-2004]

Utility Area	Metric/LGE Performance		LGE Rank Out of IOU Holding Companies
Generation	Non-fuel O&M/ MWH of Production	$4.16	4th —Top Decile
Transmission	Cash Cost/ Transmission Mile	$11,071	17th — Top Quartile
Distribution[1]	Cash Cost/ Customer	$142	6th — Top Decile
Retail[2]	O&M Cost/ Customer	$40	11th — Second Decile
Corporate A&G[3]	A&G Cost/ MWh of Sales	$2.77	8th — Second Decile

[1] LGE adjusted -$25M for Storm costs and +6.0M for FERC account coding reclassifications
[2] LGE adjusted +$8M for FERC account coding reclassifications
[3] LGE adjusted -$129M of VDT amortization costs and -$14M FERC account coding reclassifications

FERC Form 1 Benchmarking Summary Results: Four Year Average [2000-2003]

Utility Area	Metric/LGE Performance		LGE Rank Out of IOU Holding Companies
Generation	Non-fuel O&M/ MWH of Production	$4.12	4th —Top Decile
Transmission	Cash Cost/ Transmission Mile	$10,258	14th — Top Quartile
Distribution[1]	Cash Cost/ Customer	$149	5th — Top Decile
Retail[2]	O&M Cost/ Customer	$41	12th — Second Decile
Corporate A&G[3]	A&G Cost/ MWh of Sales	$2.62	7th — Top Decile

[1] LGE adjusted -$9.5M for Ice Storm costs and +6.0M for FERC account coding reclassifications
[2] LGE adjusted +$8M for FERC account coding reclassifications
[3] LGE adjusted -$97M of VDT amortization costs and -$14M FERC account coding reclassifications

List of Vertically Integrated Holding Companies used for Consolidated O&M View for the Past Three Studies

Total O&M Rankings [2013-2017]	**Total O&M Rankings [2012-2016]**	**Total O&M Rankings [2011-2015]**
Holding Company	Holding Company	Holding Company
NextEra Energy, Inc.	NextEra Energy, Inc.	NextEra Energy, Inc.
Entergy Corporation	Entergy Corporation	Entergy Corporation
Berkshire Hathaway Inc.	AEP	AEP
AEP	Berkshire Hathaway Inc.	OGE Energy Corp.
OGE Energy Corp.	OGE Energy Corp.	Berkshire Hathaway Inc.
ALLETE, Inc.	Avista Corporation	Avista Corporation
Dominion Energy, Inc.	ALLETE, Inc.	Cleco Corporate Holdings
Avista Corporation	Cleco Corporate Holdings LLC	LKE
LKE	LKE	ALLETE, Inc.
Cleco Partners LP	Dominion Energy, Inc.	Dominion Resources, Inc.
Duke Energy Corporation	FirstEnergy Corp.	FirstEnergy Corp.
Southern Company	Southern Company	NorthWestern Corp
Emera Incorporated	NorthWestern Corporation	SCANA Corporation
SCANA Corporation	SCANA Corporation	Ameren Corporation
Ameren Corporation	Ameren Corporation	Southern Company
NorthWestern Corporation	Duke Energy Corporation	Otter Tail Corporation
Puget Holdings LLC	Emera Incorporated	Emera Incorporated
FirstEnergy Corp.	Puget Holdings LLC	Duke Energy Corp
IDACORP, Inc.	IDACORP, Inc.	Puget Holdings LLC
AES Corporation	Xcel Energy Inc.	IDACORP, Inc.
Xcel Energy Inc.	Otter Tail Corporation	Iberdrola, S.A.
Great Plains Energy Inc	Great Plains Energy Inc	Xcel Energy Inc.
Iberdrola, S.A.	Iberdrola, S.A.	Great Plains Energy Inc.
Otter Tail Corporation	AES Corporation	MDU Resources Group
Portland General Electric Co	Portland General Electric Co	Portland General Electric
El Paso Electric Company	Black Hills Corporation	Black Hills Corporation
Vectren Corporation	MDU Resources Group, Inc.	Empire District Electric
Black Hills Corporation	Algonquin Power & Utilities	AES Corporation
Pinnacle West Capital Corp	El Paso Electric Company	NiSource Inc.
MDU Resources Group, Inc.	Vectren Corporation	Vectren Corporation
Algonquin Power & Utilities	NiSource Inc.	El Paso Electric Company
Westar Energy, Inc.	Pinnacle West Capital Corp	Westar Energy, Inc.
NiSource Inc.	Westar Energy, Inc.	Pinnacle West Capital Corp
Edison International	Edison International	Fortis Inc.
PNM Resources, Inc.	PNM Resources, Inc.	Edison International
Sempra Energy	Fortis Inc.	PNM Resources, Inc.
Fortis Inc.	Sempra Energy	Eversource Energy
Eversource Energy	Eversource Energy	Sempra Energy
PG&E Corporation	PG&E Corporation	PG&E Corporation
Caisse de dépôt et placement du Québec	Caisse de dépôt et placement du Québec	Caisse de dépôt et placement du Québec
Consolidated Edison, Inc.	Consolidated Edison, Inc.	Consolidated Edison, Inc.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 3

Responding Witness: Robert M. Conroy

Q-3. Refer to the direct testimony of Kent W. Blake, page 17, wherein he states, "the Companies' average residential rates remain some of the lowest in the state."

a. Provide support for this assertion.

A-3. See the response to PSC 2-2.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 4

Responding Witness: David S. Sinclair

II. OVEC

Q-4. Refer to the direct testimony of David S. Sinclair, page 30, wherein he described "Purchased Power."

a. Is the Ohio Valley Electric Corporation ("OVEC") purchased power expense considered market economy? If the response is in the negative, why not?

b. Compare the OVEC purchase power expense by MWh to the market economy purchased power expense for the past 3 calendar years, the base period and forecasted test period.

c. Explain whether continued operation, and subsequent Company ownership, of OVEC is economic.

A-4.

a. No. The Companies do not label OVEC purchases as "market economy." The "market economy" label is used to refer to purchases from the markets at large and their many participants, not from long term purchase power agreements into which the Companies have each entered, such as the Companies' agreement with OVEC.

b. See the following table. The market economy prices reflect the cost of the Companies' executed market purchases, not the average market price. The Companies purchase market energy when it's less expensive than the marginal energy cost of their own units and when transmission capacity is available to import energy from the market.

$/MWh	**OVEC Energy and Demand**	**OVEC Energy Only**	**Market Economy**
2015	62.69	28.49	20.27
2016	55.77	26.91	12.62
2017	60.41	24.62	16.99
Base Period	62.59	23.78	36.03
Test Period	75.31	24.86	39.58

c. OVEC's continued operation is determined by its board. It is economic for the Companies to continue purchasing energy from OVEC, given the Companies' obligation to participate through 2040 in the Inter-Company Power Agreement, which was amended in 2010 and approved by the Kentucky Public Service Commission in Case Nos. 2011-00099 and 2011-00100.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 5

Responding Witness: David S. Sinclair

Q-5. Regarding the Company's ownership interest in the OVEC:

a. Provide the annual sums of energy, in MWh, that LG&E purchases from OVEC.

b. Confirm that LG&E's current ownership interest in OVEC is 5.63%, and KU's ownership interest is 2.50%.

c. State whether the annual energy purchases from OVEC are contractually required as a firm commitment. If not, describe under what circumstances LG&E and KU are or may be able to modify or eliminate its OVEC purchases.

d. Provide the rate at which LG&E purchases power from OVEC under the inter-company power agreement ("ICPA"), both with and without sunk costs.

e. Confirm that in 2010, OVEC's owners extended the ICPA to the year 2040.

f. Confirm that in 2040, both OVEC generating stations will be 85 years old.

g. Confirm that in Case Nos. 2011-00099 and 2011-00100,[1] LG&E and KU in their supplemental responses to PSC 2-1 provided a copy of an independent technical review conducted by URS Corporation of OVEC's Kyger Creek and Clifty Creek generating stations ("Report"),[2] which stated that although the

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[1]Case No. 2011-00099, Verified Application of Louisville Gas & Electric Co. for an Order Pursuant to KRS 278.300 and for Approval of a Long-Term Purchase Contract, and Case No. 2011-00100, Verified Application of Kentucky Utilities Co. for an Order Pursuant to KRS 278.300 and for Approval of a Long-Term Purchase Contract.
[2]Accessible at: https://psc.ky.gov/PSCSCF/2011%20cases/2011-00099/20110711_LGEs%20Response%20to%20Commission%20Staffs%20Supplemental%20Response%20Question%20No%201.pdf

stations could continue operating through 2040, major risks included, inter alia, any potential "major shift in fuel prices and technologies."[3]

h. Provide the most recent data regarding the extent to which the Clifty Creek and Kyger Creek stations have been depreciated. Provide each station's net book value.

i. Provide the most recent data regarding the extent to which OVEC's transmission plant has been depreciated. Provide the transmission plant's net book value including the asset and reserve. Also provide the depreciation rates and average service lives.

j. Provide the total energy production (excluding station use) of the Clifty Creek and Kyger Creek stations in MWh for each of the past seven years.

k. Confirm that FirstEnergy Corporation has three unregulated subsidiaries[4] whose combined OVEC ownership interest totals 8.35%.

l. Confirm that on March 31, 2018 FirstEnergy Solutions Corp. filed a petition in the Northern District of Ohio seeking voluntary Chapter 11 bankruptcy.

m. Confirm that the bankruptcy court has granted FirstEnergy Solutions Corp.'s motion to terminate its partnership in OVEC.[5]

n. Confirm that as a result of the granting of the motion described in subpart (m), above, costs that FirstEnergy Solutions Corp. would have paid instead will be re-allocated among the remaining OVEC owners, including LG&E and KU.

o. Provide the additional costs LG&E and KU customers will have to pay as a result of the re-allocation of OVEC costs described in subpart (n), above.

p. Confirm that FirstEnergy Solution's bankruptcy petition included analysis indicating that over the remaining 22-year projected lifespan of the two stations, the remaining owners of OVEC are collectively projected to lose in excess of $5 billion.

q. Confirm that OVEC's plants are currently being subsidized by ratepayers residing in the state of Ohio.

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[3] Report, at 3-4.
[4] Allegheny Energy Supply (3.01%), FirstEnergy Solutions Corp. (4.85%), and Monongahela Power Co. (0.49%).
[5] Accessible at: https://www.eenews.net/assets/2018/05/24/document_pm_02.pdf

r. Confirm that if the State of Ohio should discontinue the subsidy described in subpart (q), above, a second re-allocation of OVEC costs will occur, causing LG&E and KU customers to pay even more for OVEC's power.

s. State whether OVEC conducts IRP analyses, and if so, with which regulator the IRP plans are filed. If available, provide a link to OVEC's most recent IRP filing.

A-5.

a. See Attachment to Tab 28 – Section 16(7)(h)(7), which contains the Companies' forecast of annual energy from OVEC for years 2018 through 2021. See also Exhibit DSS-5 attached to Mr. Sinclair's testimony, which contains the Companies' actual and forecast energy from OVEC in the base and forecasted test periods.

b. Confirmed. LG&E's current ownership interest in OVEC is 5.63%, and KU's ownership interest is 2.50%. These figures also reflect each company's Power Participation Ratio in their participation with OVEC and other contracting parties in the Inter-Company Power Agreement ("ICPA") to purchase power from the OVEC units.

c. As defined in the ICPA, LG&E and KU each have a firm contractual commitment to take their percent ownership share of the minimum output from each available online OVEC generator on an hourly basis. In an hour, any energy that is available from the Companies' share of the generation resources above the minimum may be scheduled.

d. It is unclear what is meant by "sunk costs" in this question. The Companies purchase power from OVEC at OVEC's actual cost per the ICPA. See the response to Question No. 4(b) for the cost per MWh.

e. Confirmed. The amended ICPA with OVEC is dated September 10, 2010, and the Kentucky Public Service Commission approved the amended contract in Case Nos. 2011-00099 and 2011-00100.

f. Confirmed.

g. Confirmed.

h. The Companies do not have access to OVEC's detailed corporate, accounting, or operating information. However, OVEC's financial statements, FERC Form 1 reports, and 2017 Annual Report are publicly available on OVEC's website at http://ovec.com.

i. See the response to part (h).

j. See the response to part (h).

k. FirstEnergy Corporation's subsidiaries have the following relationship with OVEC:
   - <u>OVEC shareholder interests</u>: Allegheny Energy Inc. (3.50%), Ohio Edison Company (0.85%) and Toledo Edison Company (4.00%).
   - <u>ICPA (power contract) power participation ratios</u>: Allegheny Energy Supply Company LLC (3.01%), FirstEnergy Solutions Corp. (in its capacity as assignee of FirstEnergy Generation, LLC) (4.85%) and Monongahela Power Company (0.49%).

l. Confirmed.

m. On August 9, 2018, the bankruptcy court issued an order granting FirstEnergy Solutions Corp.'s (FES) and FirstEnergy Generation, LLC's motion to reject the ICPA power contract, effective July 31, 2018. OVEC and certain other interested parties have appealed that order (as well as other aspects of the bankruptcy proceeding) to the U.S. Court of Appeals for the Sixth Circuit.

n. The ICPA, by its terms, provides that parties, such as LG&E/KU, can only be billed for (i) their "power participation ratio" share (8.13% in LG&E/KU's combined case) with respect to demand charges, which generally represent OVEC's current and future fixed costs and (ii) with respect to energy charges, power they actually take. The ICPA further provides for "several, but not joint liability" meaning that each contract party, including LG&E/KU, can only be responsible for their agreed duties/obligations and not responsible for breaches or defaults of other parties. LG&E/KU believe this contract structure should be interpreted and enforced to prohibit direct or forced allocation or transfer of any former FES-share demand or energy charges to other ICPA parties. It is possible that the FES bankruptcy and OVEC's response to it could affect OVEC's costs or expenses (such as increased borrowing costs, etc.) of which LG&E/KU would be responsible for their 8.13% share of such (but LG&E/KU should not be charged FES 4.85% or any portion thereof). This effect is not unlike movement in OVEC's costs or expenses over time due to external events (such as changes in interest rates, environmental laws, wage levels, fuel prices, etc.)

o. See the response to part (n). Such costs, if any, are speculative and not determinable.

p. LG&E/KU is not able to address this question. LG&E/KU is not currently aware of the specific $5 billion analysis or amount described, its calculation, inputs or assumptions, including whether or not it simply represents estimated aggregate operating costs or amounts and characterizes them as "losses."

q. The Companies object to the request to the extent it asserts a legal argument and does so without any foundation. Without waiver of this objection, the Companies are not aware of a subsidy being provided by Ohio ratepayers to OVEC.

r. The Companies object to the request to the extent it asserts a legal argument and does so without any foundation. Without waiver of this objection, see the response to part (q).

s. OVEC only generates and transmits power, it does not serve a load obligation and therefore has no need to conduct IRP analyses.

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Question No. 6

Responding Witness: Christopher M. Garrett

Q-6. Provide a detailed discussion of how LG&E accounts for its respective share of OVEC costs, and how these costs are passed on to retail ratepayers.

a. Identify where in the application all of these costs can be found.

b. Identify all journal entries the Companies make with regard to OVEC costs.

A-6.

a. OVEC costs are included in Account 555, Purchased Power on Schedule C-2.1, Tab 56 of the Filing Requirements. See the response to KIUC 1-65 for a detailed breakdown of Purchased Power costs.

b. LG&E records journal entries to accrue purchased power from OVEC based on estimated invoices sent by OVEC and to true-up the estimated amounts to the actual amounts when the final invoice is received from OVEC.

DR 555015 Energy Expense
DR 555016 Demand Expense
CR 232010 Wholesale Purchases Accounts Payable

Energy costs are recovered through the fuel adjustment clause, and demand costs are recovered through base rates.

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Question No. 7

Responding Witness: Lonnie E. Bellar

Q-7. Reference the Bellar testimony, p. 40, lines 3-16, in which he describes a project to add 345kV reactors to the Trimble County transmission substation, designed to prevent an overload of the 12.5 mile-long Trimble County to Clifty Creek 345 kV line during an outage of a neighboring system's transmission line. The line connects Trimble Station to OVEC's Clifty Creek Station. Mr. Bellar states "This is a major transmission line impacting power flows to and from other regional transmission systems."

a. Given that the $2.9 million project, which apparently is being funded by LG&E-KU ratepayers, provides so much benefit and value to OVEC and other transmission owners and utilities in the region, state whether the Companies have attempted to obtain at least partial funding from these other entities.

b. Confirm that the project also benefits the PJM regional transmission organization.

c. State whether any other utilities that will benefit from this project have applied for any funding for the project, for example, through PJM as an RTEP project. If so, provide complete details.

A-7.

a. The primary functions of the Trimble County to Clifty Creek 345 kV line are to bring LG&E/KU's ownership share of power from OVEC Clifty Creek into LG&E/KU's electrical system and to provide an outlet for Trimble County generation. Trimble County generation would be limited below its capability without this line. In addition, the line increases LG&E/KU capacity to import and export power to neighboring systems.

The Companies have not attempted to obtain partial funding from other entities for the Trimble County reactor project. This project was identified as part of the Companies' annual transmission expansion planning process, which identifies constraints on the LG&E/KU transmission system and solutions to the sole benefit of LG&E/KU customers. This project addresses and corrects a deficiency identified through the application of the system performance requirements mandated in North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001.[6] LG&E/KU performs the assessment of the LG&E/KU transmission system required in NERC TPL-001 as part of the Companies' transmission expansion planning process. In the event that the planning assessment results indicate that the LG&E/KU transmission system does not meet system performance criteria specified in NERC TPL-001, the standard requires the Companies to mitigate this deficiency to achieve required system performance. The Trimble County reactor project is the lowest cost solution to address the NERC TPL-001 deficiency for the Trimble County to Clifty Creek 345 kV line.

Any benefits to PJM, or any other neighboring systems, are coincidental and were not considered in the decision to move forward with this project.

As the Trimble County reactor project is a reliability upgrade, the revenue requirement associated with this project will be incorporated into LG&E and KU's OATT transmission service rates. Therefore, OATT transmission service customers will also pay a portion of the revenue requirement associated with this project.

b. See the response to part a.

c. No.

[6] NERC Reliability Standard TPL-001-4 was approved by the Federal Energy Regulatory Commission in Order No. 786, 145 FERC ¶61,051 (2013), with a January 1, 2015 effective date and is available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf.

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Question No. 8

Responding Witness: Elizabeth J. McFarland

III. GENERAL

Q-8. Refer to the direct testimony of Paul W. Thompson, page 11, wherein he discusses the Companies' "first 500-kilowatt increment for the Companies' voluntary Solar Share Program." Further reference is made to the November 5, 2018, letter from Rick E. Lovekamp filed electronically in Case No. 2016-00274, wherein he states, "the Companies have now completed the land purchase and have issued a Request for Proposal with regard to construction of the first Facility." Further reference is made to the Companies' July 2, 2016, application in Case No. 2016-00274 wherein the Companies stated that they had selected a contractor to construct the facilities, "[t]hrough a competitive request-for-proposals process" and included a copy of the contract between the chosen contractor and the Companies.

a. Explain why the Companies informed the Commission in the referenced post-hearing correspondence that they had issued a Request for Proposal, when in the application for approval of the Solar Share program they had asserted that they had chosen a contractor and provided a copy of the contract.

b. Confirm that Exhibit 3 to the referenced application, described as the "preliminary design specifications for Solar Share Facility No. 1" was completed by and bears the name of the chosen contractor from the original "competitive request-for-proposal[]."

c. Did the Companies terminate the contract pursuant to section 7 of the contract provided as Exhibit 4 of the referenced application? If the answer is in the affirmative, provide a copy of the termination notice provided by the Companies. If the response is in the negative, explain whether the contract is still in place, and if so, what the purpose of the Request for Proposal referenced by Mr. Lovekamp is for.

A-8.

a. In Case No. 2016-00274, the Companies executed a contract as a result of a competitive bid process. In November 2018, the Companies determined that an Engineering, Procurement, and Construction contract would best serve the Companies and their customers because one contractor would be responsible for both the first array and all of the common infrastructure. Obtaining current pricing from the market assures that our customers get the most recent and competitive costs.

b. Confirmed. Exhibit 3 in Case No. 2016-00274 does bear the name of the contractor from the original competitive bid process.

c. The Companies have not terminated the contract that was provided as Exhibit 4 in Case No. 2016-00274. The contract had no provision which provided exclusive right of the contractor to any projects the Companies may pursue. The RFP referenced in Mr. Lovekamp's letter was for the reasons described in response to part a.

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Question No. 9

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-9. Refer to the direct testimony of Kent W. Blake, pages 10-11, wherein he discusses the Companies' Merger Mitigation Depancaking ("MMD") transmission rate mechanism.

a. Does the MMD have the effect of reducing transmission revenues paid by certain municipalities, thus increasing the revenue requirement as compared to a scenario where the MMD does not exist?

b. How many years has the MMD been in effect?

c. Did the Kentucky Public Service Commission approve the MMD?

d. Is it fair to describe the MMD as a necessary effect of the Companies' merger activity and withdrawal from the Midcontinent Independent System Operator ("MISO")?

e. Should the Federal Energy Regulatory Commission ("FERC") approve the Companies' requested elimination of the MMD charges, explain what effect on retail rates the decision will have in the context of this case.

A-9.

a. MMD applies differently to exports to the Midcontinent Independent System Operator ("MISO") and imports from MISO. Under MMD, transmission charges for the combined transmission system of LG&E and KU for exports to MISO are waived for certain municipalities, reducing transmission revenues paid by those municipal customers. For imports of electricity from a source in MISO for delivery to load interconnected to the combined transmission system of LG&E and KU, under MMD, certain municipalities are billed for LG&E and KU transmission charges but LG&E and KU are obligated to credit to those municipal customers the MISO transmission charges associated with the delivery of the electricity to the MISO-LG&E/KU border. This typically results in a net payment to those municipal customers because the MISO transmission charges exceed the LG&E and KU transmission charges. As a result of these waived transmission charges and the crediting of MISO transmission charges, MMD causes an increase in the LG&E and KU transmission revenue requirement.

b. 12 years; MMD has been in effect since 2006. However, not all parties eligible for MMD have had import and/or export transactions with MISO to date. The cities of Princeton, Paducah, Paris, Benham, and Owensboro Municipal Utilities have had such transactions and have incurred MMD costs that increase the revenue requirement. Starting in May 2019 additional KU wholesale municipal customers will have MMD transactions. Additionally, Owensboro Municipal Utilities has recently made a claim for applicability of MMD to certain of its MISO-related transactions, which claim is currently being contested by LG&E and KU and is pending before FERC.[7]

c. MMD is a transmission rate mechanism that applies to certain specific customers that take transmission service under the Companies' Open Access Transmission Tariff on file with FERC. As this mechanism applies to FERC-jurisdictional transmission service, it is required to be, and is a rate on file with FERC and not the Kentucky Public Service Commission. That said, the Commission was aware of FERC's March 17, 2006, conditional approval of the Companies' withdrawal from MISO when the Commission issued its own May 31, 2006 order authorizing the Companies to withdraw.[8] The Commission further demonstrated its awareness of, and its consent for the Companies to recover through rates, MISO-exit-related transmission costs in its final orders in the Companies' 2008 base-rate cases.[9]

d. In 1998 when the Companies sought FERC approval for the LG&E and KU merger, FERC determined that the merger raised horizontal market power issues. Ultimately FERC approved the merger, citing to MISO participation as part of the basis for satisfying these horizontal market power concerns. When the Companies sought FERC approval to withdraw from MISO, FERC required continued mitigation for the horizontal market power concerns through some other kind of mechanism. MMD was proffered as an alternative means of continuing horizontal market power mitigation. As such, a more accurate description would be that MMD satisfies the Federal Power Act Section 203 mitigation requirements that FERC required when LG&E and KU merged in 1998, as modified by FERC's orders approving the Companies' withdrawal from MISO in 2006.

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[7] FERC Docket No. EL18-203-000.
[8] Case No. 2003-00266, Order at 26 (May 31, 2006) ("On March 17, 2006, FERC granted conditional approval for LG&E and KU to withdraw from MISO.").
[9] *See* 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).

e. As discussed in the testimony of Mr. Blake, the Companies' revenue requirement and the rates proposed in this proceeding reflect the MMD charges. If the FERC grants the Companies' request during the pendency of this proceeding, the Companies will address the effect on the revenue requirement. However, it is not known when FERC would issue such an order or when the elimination of MMD would be made effective.

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Question No. 10

Responding Witness: David S. Sinclair

Q-10. Refer to the direct testimony of Lonnie E. Bellar, page 18, wherein he states that the Brown solar facility "was offline due to darkness or weather conditions 51.6 percent of the time."

a. Explain, in detail, what Mr. Bellar means by "offline."

A-10. "Offline" means that the Brown Solar facility is not supplying energy to the electrical grid.

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Question No. 11

Responding Witness: Lonnie E. Bellar

Q-11. Refer to the direct testimony of Lonnie E. Bellar, page 22, wherein he notes that "Natural gas boiler firing also increases the life of the air heater baskets and the pulse jet fabric filter bags designed to collect particulate from the boilers, as well as improving startup efficiency."

b. Have these improvements in life expectancy and efficiency been taken into account in the instant application in terms of overhaul schedules, outage-related investments or O&M reductions?

A-11. The project has not been in place for sufficient time to accurately judge the impact on O&M costs. Pulse Jet Fabric Filter (PJFF) bags and air heater baskets are monitored, inspected, and sampled, to assess their condition. The decision to replace these components is based on the condition assessment, and future outage plans will be adjusted accordingly. The duration of outages is governed by other factors, such as other planned work during said outage.

Replacement of PJFF bags and air heater baskets are capital expenditures, so there would be no outage related O&M reductions, rather a change in capital expenditures schedule.

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Question No. 12

Responding Witness: Lonnie E. Bellar

Q-12. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, generally.

a. Explain why the Companies did not contract with an independent entity or organization with expertise or insight into RTO membership in order to perform an unbiased analysis.

A-12.

a. As demonstrated by Exhibit LEB-2, the Companies conducted a thorough and unbiased analysis of RTO membership without incurring the significant expense of paying a third party to do so. The Companies were founding members of the MISO RTO and regularly transact in PJM and MISO, so they have ample experience and expertise to conduct the RTO membership analysis the Companies provided in Exhibit LEB-2.

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Question No. 13

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-13. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 5 of 40, wherein the study states, "the Companies are market participants in, and regularly transact in, both RTOs."

a. Explain the Companies' involvement in RTOs since their withdrawal from MISO, including which markets they have participated in, and generally, their level of involvement in those markets.

A-13.

a. Since the Companies' withdrawal from MISO, the Companies have actively participated in the real-time energy markets administered by both MISO and PJM. The Companies monitor the RTO markets to identify opportunities for off-system non-firm hourly sales and economy purchases. The volume and frequency of transactions vary due to the volatility of market prices and the availability of excess generation for off-system sales. Because RTO markets continue to evolve, the Companies will continue to monitor them for other transactions that will optimize the Companies' assets and reduce the cost of service to customers. Additionally, the Companies have received responses to past capacity and energy RFPs from resources that were located in RTOs and have had to evaluate these resources in light of their RTO location.

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Question No. 14

Responding Witness: Lonnie E. Bellar

Q-14. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 7 of 40, wherein one "Key Assumption []" was that the "Companies did not use generator specific or load-specific Locational Marginal Pricing ("LMP") models.

a. Explain why this assumption or methodology was reasonable.

A-14.

a. Forecasting future LMP and RTO congestion cost is a highly complex analysis that is subject to a range of variables. Such studies typically yield a broad range of outcomes. In addition, LMP is in place to drive behaviors that minimize or eliminate congestion over time, so any significant costs or benefits should be considered short term anomalies. As regulated utilities, the Companies' objective is to hedge exposure to congestion costs and not speculate. For these reasons and the fact that expecting a certain amount of cost or revenue from LMP could impact the outcome of the analysis, the Companies used their existing energy price forecast scenarios for market prices as a reasonable proxy for the LMPs that would be created if the Companies joined an RTO. These theoretical LMPs do not exist and could vary higher or lower than the average RTO market price on a 5-minute basis, depending on actual system conditions. The Companies assumed that the LMPs would average close to the general market price over time, but did not speculate on the potential transmission congestion that might cause temporary deviations.

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Question No. 15

Responding Witness: Lonnie E. Bellar

Q-15. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 7 of 40, wherein one "Key Assumption[]" was "No changes to the Companies' generating fleet occurring during the analysis time period."

a. Confirm this assumption is consistent with the Companies' current plans outside of RTO membership.

A-15.

a. The assumption, "No changes to the Companies' generating fleet occurring during the analysis time period," from Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 7 of 40, is consistent with the Companies' current plans outside of RTO membership.

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Question No. 16

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-16. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 15 of 40, wherein it references the Companies' target summer reserve margin of 16 percent to 21 percent.

a. Is this the Companies' current, future and past target summer reserve margin? If the response is in the negative, provide the summer target reserve margin currently, the estimate assumed in the Companies' 2018 IRP and the margin for each of the past 5 years.

A-16.

a. No. The target reserve margin range of 16 to 21 percent reflects the Companies' reserve margin range for the past five summers, since the range was developed for the Companies' 2014 IRP. In October 2018, the Companies filed their 2018 IRP, which included an updated current/future target summer reserve range of 17 percent to 25 percent. However, because no changes to the Companies' generating fleet is forecasted to occur during the 2018 RTO Membership Analysis's time period, as noted in the response to Question No. 17, the updated target reserve margin range would have no impact on the RTO membership analysis.

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Question No. 17

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-17. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 18 of 40, wherein the risk associated with Capacity Performance was discussed.

a. Confirm that along with charges for non-performance, the PJM Capacity Performance construct also provides for payments to generators who perform during assessment intervals.

b. Cite to the portion of LEB-2 that discusses these payments, as opposed to assessments, associated with Capacity Performance.

A-17.

a. Confirmed.

b. Bonus Performance Credits follow the same billing methodology as Non-Performance Charges. While the risk of additional costs to customers was noted, neither Non-Performance Charges nor Bonus Performance Credits have been factored into the analysis due to their uncertainty.

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Question No. 18

Responding Witness: Lonnie E. Bellar / David S. Sinclair

Q-18. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 30 of 40, Appendix D, wherein the document states, "although RTO membership is assumed to result in a decrease in the reserves necessary to meet the contingency reserve requirement, the benefit of this reduction in the reserves requirement alone is not a major driver of net costs or benefits."

c. Confirm that revenues from the capacity auctions of either RTO would be considered "a major driver of net benefits."

d. Confirm that if the Companies were indeed winter-peaking, revenues derived from the capacity auctions of either RTO would be a larger driver of net benefits than if the Companies 'target reserve margin was based on their summer peak.

A-18.

c. Confirmed. The revenues from the capacity auctions are considered a potential major driver of net benefits, as shown in the 2018 RTO Membership Analysis in Section 7.2.3 and Appendix B. However, the comment quoted above regarding contingency reserve requirements is in reference to online operational reserves to support dispatching the system to meet momentary load, not the generating capacity that could be sold into the forward capacity auctions.

d. The Companies have not performed this analysis.

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Question No. 19

Responding Witness: Lonnie E. Bellar

Q-19. Reference the final draft MISO 2018 MTEP Report, accessible at the link below.[10] At p. 165, the report states that outside of the regional planning process of the Southeastern Regional Transmission Planning Organization (SERTP), MISO is working with TVA and LG&E on "Market Congestion Planning Study project PC-4" to address "congestion on the Southern Indiana/Kentucky border."

a. Does the "Market Congestion Planning Study project PC-4" have any LG&E or KU ratepayer impact in the current rate cases? If so, describe in full and identify where in the applications it can be referenced.

b. Explain if any MISO-member utilities would participate in the project.

c. If the project does not have any rate impact in the current cases, state whether it might in the future, and if so, provide a discussion of the nature of the project, how it would benefit LG&E-KU, and the extent to which LG&E-KU ratepayers would be expected to fund it.

A-19.

a. No.

b. LG&E/KU is not a party to the MISO PC-4 project. As such LG&E/KU do not know if any MISO members are participating in this project.

c. LG&E/KU has a project (referenced in the MISO MTEP PC-4) which was completed in 2018. LG&E/KU's cost of this project was less than $50k. LG&E/KU provided MISO details of LG&E/KU's project. The MISO MTEP report reference to LG&E/KU was only to document that coordination between the two parties related to each parties separate projects was occurring.

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[10] https://cdn.misoenergy.org/MTEP18 Full Report264900.pdf

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Question No. 20

Responding Witness: Lonnie E. Bellar

Q-20. Refer to the direct testimony of Lonnie E. Bellar, page 57, wherein he discusses the target RIIR for contractors.

a. Provide the target RIIR for employees for 2018 through July and 2018 calendar year.

A-20.

a. The Corporate Recordable Illness and Injury Rate Target for 2018 is 1.30. The RIIR target for employees is effective for the full calendar year.

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Question No. 21

Responding Witness: Lonnie E. Bellar

Q-21. Refer to the direct testimony of Lonnie E. Bellar, page 58, wherein he discusses PHMSA's pending Plastic Pipeline Rule.

a. Provide all formal comments LG&E has submitted on the rule, either on its own behalf, or as part of a trade organization or other entity.

b. If additional action by PHMSA is taken on this rule during the pendency of this matter, provide an update of same, including the Company's position on PHMSA's action and whether it will have any material impact on the Company's plans or customers.

A-21.

a. LG&E did not submit comments on its own behalf. See attached for the AGA comments submitted in regards to the Plastic Pipe Rule.

b. The final rule has just been issued and the Plastic Rule citation is 83FED.REG.58694 (November 20, 2018). The effective date will be January 22, 2019.

In the final rule PHMSA has decided to delay action on the Tracking and Traceability portion of the proposed rule until a later date. These issues may be revisited in either a subsequent final action or a new rulemaking project. However, the rule will still require that plastic components have the barcode and PHMSA notes that operators are required to have a level of tracking and traceability information for components since the Distribution Integrity Management Program (DIMP) regulations in § 192.1007(a)(5) require that operators capture and retain data on the location where new pipeline is installed and the material of which it is constructedThe final rule is not expected to materially change LG&E's Gas Inspection, Tracking and Traceability program plans, because the planned technology will provide greater knowledge of the Company's plastic pipeline and component information, including location. LG&E is continuing to evaluate the impacts of the remaining parts of the Plastic Pipe Rule which was published in the Federal Register on November 20, 2018.

BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
WASHINGTON, D.C.

Notice of Proposed Rulemaking Pipeline Safety: Plastic Pipe Rule	}	Docket No. PHMSA-2014-0098

COMMENTS OF THE AMERICAN GAS ASSOCIATION TO PHMSA NOTICE OF PROPOSED RULEMAKING: PLASTIC PIPE RULE

Founded in 1918, the American Gas Association (AGA) represents more than 200 local energy companies that deliver clean natural gas throughout the United States. Today, more than 68 million residential, commercial and industrial customers across the nation receive their reliable, affordable supplies of natural gas from AGA members—and natural gas meets almost a quarter of America's energy needs.

I. General Comments

AGA appreciates the opportunity to comment on the Notice of Proposed Rulemaking (NPRM) published on May 21, 2015 (80 FR 29263). AGA supports many of the proposed changes found within the proposed rule. However, AGA requests that PHMSA remove Tracking & Traceability from the Plastic Pipe Rule. Due to the complexity and potential magnitude on the industry that the Tracking & Traceability requirements may have, AGA believes discussions and cost-benefit analyses associated with this topic will inhibit progression of the remainder of the rule. The proposed rule contains many elements of positive impact to the industry and pipeline safety, which, AGA would like to see implemented. In the next section of the comments AGA provides detailed remarks on the full NPRM. Within the specific comments AGA has outlined areas where further clarification is necessary or provides slight modifications to PHMSA proposals for the thoughtful advancement of pipeline safety.

II. Specific Comments

A. Tracking & Traceability

AGA understands PHMSA's attempt to codify material Tracking & Traceability within the natural gas industry, however research on and the implementation of this initiative remains in its infancy. The total impact of completing system-wide Tracking & Traceability on pipe and components is not fully understood and should be further explored prior to codifying the requirement. Due to the significance and potential cost of implementation, AGA encourages PHMSA to remove it from the Plastic Pipe Rule. The Tracking & Traceability requirements for plastic pipe and components should be evaluated with the intent that the same system modifications and processes could also be utilized by operators for all material types. AGA believes addressing Tracking & Traceability independently for each material type is short sighted and will cause the industry to spend additional resources without added benefits.

The ability for gas operators to perform Tracking & Traceability is dependent upon process integration across multiple company functions. The necessary initiatives to create and implement Tracking & Traceability Programs (TTP) are not limited to just pipeline system installations or maintenance checks. Instead, installation and maintenance activities provide the final outcome only after a long list of actions has first been accomplished. TTP's require the integration of administrative departments, including product estimating, procurement, materials warehousing, information technology, and training. Within each of these functions numerous activities are required, such as contract creation, receipt of material, detailed information system planning, detailed employee training, and much more. This wide breath of impacted activities and departments exemplifies the necessity for a separate rulemaking and a phased approach to implementation.

Even after robust TTPs have been developed, the Traceability aspect of PHMSA's proposed regulation will require numerous Geospatial Information System (GIS) enhancements for a majority of the industry. It is unclear in the proposed rule if PHMSA's final intent is for operators to have the capability to locate specific pipe components to a high degree of accuracy within their systems. In order to accomplish this, operators will need to implement advanced GIS systems for their distribution piping systems, thus furthering the significance of this rulemaking.

Table 1 outlines three examples from AGA member companies that display the high level of significance that this rule will have on operators. The table summarizes the current status of an operating company's ability to achieve Tracking & Traceability on plastic pipe and components, the additional actions needed to meet PHMSA's proposal and the estimated cost to make those changes. It is apparent each one of these operators has taken actions prior to the release of the proposed rule; however, they would still have to expedite their initiatives to invest further in order to fully comply with PHMSA's proposed regulatory changes. In all of these situations the need to invest is substantial and should be phased in over several years.

Table 1: Example Tracking & Traceability Improvements and Associated Costs

Company	Current Tracking & Traceability Status	Projected Modifications Needed	Estimated Cost
A	Recently implemented work management and mobile data solutions at a cost of $20M. These solutions provide the foundation to support the collection, storage and utilization of tracking and traceability data.	Project modifications include the conflation of GIS mapping system, purchase of ruggedized barcode scanners with Bluetooth capability and sub meter GIS accuracy, IT programing changes, testing and training Additional increase in annual operating costs include barcode scanner replacement, IT support, data collections and data management	Implementation Cost: $ 11.375M Annual Increase: $2.85 M
B	Completed GIS Mapping conflation exercise to enable accurate Traceability data entry.	Purchase of Hardware (ruggedized barcode scanners) and implementation, programming and training of necessary IT Systems. Increased annual costs including barcode scanner replacements, IT support and data management.	Implementation Cost: $ 18.75 M Annual Increase: $3.25 M
C	Implemented GIS Mapping for Distribution System.	Implement Data and Document Management Systems, including Construction & Mapping. Purchase Hardware (data storage, GPS, barcode readers, software, etc.) Increased annual costs including hardware replacements, materials management personnel and technical support for enterprise systems and engineering.	Implementation Cost: $9.4M Annual Increase: $4.1M

AGA would also like to encourage PHMSA to align the material traceability attributes listed in the proposed §192.3: *Traceability,* with the information currently captured per ASTM F2897-11a: *Standard Specification for Tracking and Traceability Coding System of Natural Gas Components (Pipe, Tubing, Fittings, Valves and Appurtenances)*. The plastic pipe and component manufacturing industry has taken steps to include all the information suggested by ASTM F2897-11a into an advanced barcoding system. Any variations from these standards will require plastic pipe and component manufacturers to modify their existing barcode systems and will require operators to modify their barcode readers or information gathering systems. AGA also discourages PHMSA from requiring items such as pressure rating and temperature rating in the required Traceability information. These ratings are already linked to the lot information and do not need to be called out separately. The separate capture and storage of the ratings and the information used to determine those ratings is unnecessary and duplicative in nature. The differences between ASTM F2897-11a and the attributes contained in PHMSA's proposal are outlined in Table 2.

Table 2: PHMSA Proposal vs. ASTM F2897-11a for Traceability

PHMSA Proposal	ASTM F2897-11a
	Manufacturer
Location of Manufacture	
Production	
Lot Information	Lot Information
	Production Date
Material	Material
Type	Type
Size	Size
Pressure Rating	
Temperature Rating	
Model	

AGA is also concerned that the barcoding requirements will prohibit competitive business practices, due to some manufacturers having not implemented pipe and component data tracking capabilities. Even when all United States manufacturers adhere to the national standard, ASTM F2897-11a, many of the international vendors that companies utilize will not have incorporated this standard into their processes. AGA cautions PHMSA that codifying such a requirement may impede competitive business.

AGA does not support the specific requirement within §192.63(e)(3) that all markings be permanent. The intent of the marking on the plastic pipe or component is to aid in the capture of Traceability data. Once the data has been captured and stored, AGA believes the marking on the pipeline is unnecessary. Therefore, when PHMSA moves forward with Tracking & Traceability, AGA suggests that PHMSA modify their proposal to require markings remain legible and visible up to twenty years. AGA believes it is unnecessary for the Traceability information to be legible and visible after the pipe or component has been installed. AGA recommends the following modified language for §192.63(e)(3).

> §192.63(e)(3) - All markings on plastic pipelines prescribed in the specification and paragraph (e)(2) shall be legible and visible in accordance with the listed specification for at least twenty years. Records of markings prescribed in the specification and paragraph (e)(2) shall be maintained for the life of the pipe per requirements of §§192.321(k) and 192.375(d).

In order to not delay the remainder of the Plastic Pipe Rule, AGA encourages PHMSA to separate out this part of the rulemaking and address it in an independent proposed rule. When Tracking & Traceability moves forward, AGA would like to encourage PHMSA to evaluate a phased approach to compliance for §192.321(k) and §192.375(d), and subsequent requirements for all pipeline materials.

After the development of industry standards, such as ASTM F2897-11a, and the incorporation of those into code, operators will still have a significant amount of preparation work to complete prior to having the ability to comply with the new regulation. Ideally a Task Group comprising of pipe and component manufacturers, industry, and federal and state regulators could help guide the implementation of Tracking & Traceability over the next several years. To begin the conversation, AGA proposes PHMSA provide a timeline for compliance, starting first with ensuring appropriate processes are in place for data transfer and capture. Then, in Phase B, allow for a period of time where operators begin to capture Traceability data. Simultaneously, in Phase C, operators will be ramping up any modifications to their systems necessary to Track the data in their systems of record, such as Geospatial Information Systems (GIS). Table 3 outlines AGA's proposed phased approach for the implementation of Tracking & Traceability on pipe and components. The phase approach over several years would also allow companies to appropriately spread the cost to comply over several budgeting cycles.

Table 3: AGA's Proposed Phase Approach to Tracking & Traceability

Phase	Implementation	Effective Date
A	Develop process to capture traceability information on pipe & components	Effective Date of Rule + 1 year
B	Begin barcoding Traceability information on pipe, valves and fittings	Effective Date of Rule + 3 years
C	Begin Tracking location of information on pipe, valves and fittings	Effective Date of Rule + 5 years

B. Design Factor of PE

AGA thanks PHMSA for addressing AGA's petition for an increased design factor for Polyethylene (PE) Pipe in this Proposed Rule. Although AGA's original petition didn't directly address pipe larger than 12-inch diameter, AGA encourages PHMSA to evaluate including larger pipe diameters in the code language and table referenced in §192.121(c)(2)(iii) and (iv) respectively. In recent years operators are starting to install larger diameter PE pipe, specifically 16-inch diameter pipe. AGA suggests PHMSA modify the code language and table referenced to include the pipe sizes incorporated in ASTM D2513-14. See below and Table 4 for AGA's suggested edits.

§192.121(c)(2)

(iii) The pipe has nominal size (IPS or CTS) of 24 inches or less; and

(iv) The wall thickness for a given outside diameter is not less than that listed in the following table:

Table 4: AGA Proposed Minimum Wall Thickness for PE Pipe

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding DR (values)
½" CTS	0.090	7
¾" CTS	0.090	9.7
½" IPS	0.090	9.3
¾" IPS	0.095	11
1" IPS	0.120	11
1 ¼" IPS ...	0.151	11
1 ½" IPS ...	0.173	11
2"	0.216	11
3"	0.259	13.5
4"	0.265	17
6"	0.315	21
8"	0.411	21
10"	0.512	21
12"	0.607	21
16"	0.762[1]	21
18"	0.857[1]	21
20"	0.952[1]	21
22"	1.048[1]	21
24"	1.143[1]	21

AGA also encourages PHMSA to allow the use of the increased design factor for certain existing pipe. When the American Society for Testing and Materials (ASTM) issued ASTM D2513-08B in 2008, the new pipe material designation codes of PE2708 and PE4710 were introduced. AGA

[1] ASTM D2513-14. *Standard Specification for Polyethylene (PE) Gas Pressure Pipe, Tubing and Fittings.* Table 4 – Wall Thicknesses and Tolerances for Plastic Pipe, Inches. July 2014.

believes that the new design factor should be allowable for pipe of these designations. The manufacturing process has remained consistent; therefore no reason exists as to why operators could not utilize the increased design factor for pipe manufactured prior to the effective date, consistent with the recognized standards.

C. Expanded Use of PA -11

AGA supports the expanded use of Polyamide-11. AGA encourages PHMSA to expand the table found in §192.121(d)(2)(iv) to include ¾-inch diameter pipe. The same minimum wall thickness and corresponding DR value can be utilized for PE and PA-11 pipe. AGA recommends that the table be modified as shown in Table 5.

Table 5: AGA Proposed Minimum Wall Thickness for PA-11 Pipe

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding DR (values)
¾” IPS	0.095	11
1” IPS	0.119	11
1 ¼“ IPS	0.151	11
1 ½“ IPS	0.173	11
2”	0.216	11
3”	0.259	13.5
4”	0.333	13.5
6”	0.491	13.5

D. Incorporation of PA-12

AGA supports the expanded use of Polyamide-12. AGA encourages PHMSA to expand the table found in §192.121(e)(3) to include ¾-inch diameter pipe. The same minimum wall thickness and corresponding DR value can be utilized for PE and PA-12 pipe. AGA recommends that the table be modified as shown in Table 6.

Table 6: AGA Proposed Minimum Wall Thickness for PA-12 Pipe

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding DR (values)
¾” IPS	0.095	11
1” IPS	0.119	11
1 ¼“ IPS	0.151	11
1 ½“ IPS	0.173	11
2”	0.216	11
3”	0.259	13.5
4”	0.333	13.5
6”	0.491	13.5

E. Risers

AGA supports GPTC's petition for the construction of risers that will allow termination of plastic pipe above ground level at the inlet or outlet of regulator and metering stations. AGA suggests that the structural support requirement, especially for service risers, be flexible to other solutions beyond just a 3 foot horizontal base leg. As long as the structural support has been designed in accordance with sound engineering practices and it will meet PHMSA's intent of adequate support to resist lateral movement, it should be allowed. Also, it is AGA's understanding that since the proposed change is within the design section of the code, this requirement is not retroactive and will not apply to risers installed prior to the effective date of the rule.

F. Fittings

AGA supports PHMSA's intent for the proposed changes to §192.455 – *External corrosion control: Buried or submerged pipelines installed after July 31, 1971.* However, in the proposed rule, PHMSA does not address the cost to comply with the proposed regulation. With this change as written, natural gas operators would need to: (1) locate all electrically isolated metal alloy fittings, (2) install cathodic protection, (3) install test stations for monitoring, and (4) develop a comprehensive monitoring program. Each of these tasks will redirect operator resources away from higher risks on the pipeline systems.

AGA does not believe the requirement for cathodic protection and monitoring should be retroactive. Instead operators should only be responsible for installing cathodic protection whenever an isolated metal alloy fitting that requires cathodic protection is exposed during excavation or installed after the effective date of the final rule. There are several mechanical fasteners or compression rings which are made of corrosion resilient alloys and have not had corrosion issues in normal buried applications. AGA believes these fittings should not be considered in the additional requirements for §192.455.

AGA also proposes the requirements for cathodic protection monitoring for these fittings should be on a modified basis from that required in §192.465(a). AGA also encourages PHMSA to explore an allowance for other cathodic protection options, such as anode bed installations with sufficient capacity to ensure the elimination of potential corrosion. AGA would like to recommend the following language for §192.455.

> §192.455 – *External corrosion control: Buried or submerged pipelines installed after July 31, 1971.*
>
> (a) Except as provided in paragraphs (b), (c), (f), and (g) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:
>
> …
>
> (g) Electrically isolated metal alloy fittings that require cathodic protection and are installed in plastic pipelines after [INSERT EFFECTIVE DATE OF FINAL RULE] not

meeting the criteria contained in paragraph (f) must be cathodically protected and monitored at a minimum of once every tenth year.

G. Plastic Pipe Installation

G1. Installation by Trenchless Excavation

AGA supports the intent of PHMSA's proposed definition for a Weak Link, but would like to provide suggested modifications. As currently written, PHMSA suggests that a Weak Link must be a specific device, such as a pull head with sheer pins. However, it is a common practice in industry for operators to utilize a plastic pipe in a smaller diameter sized pipe that is designed to fail before the carrier material yields as a Weak Link. AGA believes if means are taken to ensure that the pipe is not damaged and there are sound engineering practices behind the use of the tool, it should be acceptable in practice.

AGA only supports the requirement for Weak Links in trenchless installations on mains but not on small diameter service lines (i.e. 1- ¼ inch IPS and smaller), as the construction techniques for small diameter service lines are not compatible with the use. In order to determine if there is a need for use of Weak Links on small diameter service lines, a detailed analysis should be performed on damages to small diameter service lines due to excess pulling that were installed through a trenchless installation method where no Weak Link was utilized. In the event that no such damages have been experienced, AGA believes there is no justification in the requirement for the use of a Weak Links on small diameter service lines.

AGA would also like to suggest modified language for §192.329(a) and §192.376(a). As currently proposed both sections indicate that it is the natural gas operator's responsibility to identify the existence of all underground facilities and accurately locate those facilities. AGA believes this is a shared responsibility for all underground utilities. If the utility is not known to the pipeline or service installer due to a lack of response to One-call or due to One-call enforcement exemptions, the operator will make every attempt to locate any facilities themselves. If an underground facility remains unknown to the operator, it negates the operator's ability to proactively ensure sufficient clearance. As currently proposed, PHMSA does not differentiate existing underground facilities and structures from those that are installed after the natural gas pipeline installation. The lack of this differentiation leaves regulatory uncertainty, therefore AGA suggests the following modified code language.

> §192.329(a) and §192.376(a) - Each operator shall ensure that the path of the excavation will provide sufficient clearance for installation and maintenance activities from other known underground utilities and/or structures at the time of installation.

G3. Qualifying Joining Procedures and G4. Qualifying Persons to Make Joints

As currently proposed in §192.281(c), PHMSA solely supports the utilization of industry standard ASTM F2620-12: *Standard Practice for Heat Fusion Joining of Polyethylene Pipe and Fittings.* This standard was qualified based on internal pipe pressures with a 0.4 Design Factor. Therefore, AGA supports the use of this single standard only for saddle fusion joint procedures, due to the fact that this is the only fusion type that is utilized on gas lines with live gas or internal pressure. However, butt and socket fusion procedures should not be restricted to ASTM F2620-12. Operators develop their procedures using a variety of resources including Plastic Pipe Institute's standard Pipe Joining Procedures, manufacturers qualified joining procedures or their own internal company qualified procedures. An example of where proven company procedures may differ from ASTM F2620-12 is in heater surface temperature ranges. Many operators have historically successfully utilized heater surface temperatures that differ from ASTM F2620-12. In many cases operators have qualified their procedures and fusers with these proven temperatures. By changing the requirement, operators would then have to requalify new procedures, modify specifications and requalify all fusers in order to accommodate the new standard. AGA believes that these proven procedures are appropriate for pipe joining, and §192.281(c) should be modified as follows:

> §192.281(c) *Heat Fusion Joints* – Each saddle fusion joint on a plastic pipe and/ or component must comply with ASTM F2620-12. Each socket or butt fusion joint on a plastic pipe and/or component must comply with a qualified fusion procedure and the following:

AGA disagrees with PHMSA's proposed language in §192.281(c)(2). Some industry operators perform socket fusion joints up to 2-inches and in specific situations may do so up to 4-inches. AGA believes there is no technical justification for the 1¼ - inch limit. AGA proposes the following modified language:

> §192.281(c)(2) - A socket heat-fusion joint equal to or less than 4 inches must be joined by a device that heats the mating surfaces of the pipe and/or component, uniformly and simultaneously, to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion. A socket heat-fusion joint may not be joined on a pipe/and or component greater than 4 inches.

G6. Installation of Plastic Pipe

For many years plastic pipeline operators have used the *PPI Handbook for PE Pipe* for construction guidance. In Chapter 7 – *Underground installation of PE pipe,* it is recommended that "the material and compaction requirements for the final backfill should reflect sound engineering practices and satisfy local ordinances and sidewalk, road building or other applicable regulations."

AGA supports sound construction installation practices that ensure the adequate support of plastic pipe. However, AGA does not support the additional backfill requirements found in §192.321(i)(2) and §192.386(c)(2). In both cases PHMSA proposes the additional requirement that backfill "be properly compacted underneath, along the sides, and for predetermined depth above the pipe." This code language is very ambiguous and will require additional clarification prior to the industry understanding the compliance burden. By choosing to require proper "compaction" versus "support," PHMSA will inadvertently require the industry to quantify the level of compaction above, around and on top of each plastic pipe main and service installation. The industry will find it necessary to determine what a "proper" level of compaction is in each of those scenarios. Compaction levels can differ greatly depending upon jurisdictional requirements from permitting agencies, soil type and conditions and whether the installation is occurring in undisturbed ground or in a previously disturbed area.

Instead, AGA suggests PHMSA modify the regulation to directly address the risks to the pipeline. If the code language is intended to prevent ring deflection or sheering stresses, operators will be able to determine what construction practices are necessary to achieve those goals. AGA suggests the following modified language for §192.321(i) and §192.386(c).

> Plastic Pipe that is being installed in a trench must comply with the following:
> (1) Backfill material in contact or close proximity to the pipe must not contain materials that could be detrimental to the pipe, such as rocks of a size exceeding those established through sound engineering practices.
> (2) Where there is potential for ring deflection or shear stresses on the pipeline due to anticipated loads, the pipeline must be properly installed with support.

<u>G8. Equipment Maintenance; Plastic Pipe Joining</u>

AGA does not support the prescriptive proposed language in §192.756 and believes the requirements as suggested are a large burden on operators. Instead, AGA requests that PHMSA limit the code requirements to §192.756(a). By doing so, the regulation will then place the ownership on the operator to determine appropriate internal programs to maintain necessary equipment maintenance records. Each operator should have an equipment maintenance program that meets equipment manufacturer's recommended practices or written standards.

AGA also reminds PHMSA that their requirements are specific to equipment calibration, however depending on the type of fusion being performed, the machine may not need any calibration and instead may only need inspections for proper maintenance.

H. Repairs

H1. Repair of Plastic Pipe

AGA disagrees with PHMSA's decision to demarcate scratches and gouges greater than 10% in §192.311: *Repair of Plastic Pipe,* as an imperfection that needs repair or removal. AGA notes that the rule of thumb of 10% of wall thickness is currently utilized by operators and is referenced in AGA's Plastic Pipe Manual. However, it is considered to be a conservative methodology adopted to ensure that the scratch or gouge is not greater than 20%, which is the industry recommendation from manufacturers and industry organizations. In 1999 several individuals from the Southwest Research Institute, University of Pennsylvania and the Gas Research Institute (GRI) presented a paper at the 16th International Plastic Pipe Fuel Gas Symposium in New Orleans, LA, titled "*Experimental Determination of Allowable Crack Depths in Polyethylene Pipes Subjected to Internal Pressure Loading.*[2]" This paper was summarized with the following conclusion:

> *None of the samples that possessed initial flaws that were 10 percent of the pipe wall thickness in depth failed during the simulated 350-year service history at nominally [140 psig] pressure and [68°F]…*
>
> *Moreover, the data for PE-B, PE-C, and PE-D pipes show that service lines are at least 350 years for nominally 30 percent initial cracks and for the latter two materials at least 250 years for nominally 50 percent cracks. For these materials and pipe sizes, the 10 percent rule of thumb is very conservative.*

The industry research utilized for the presentation is found in the paper "*Service Performance of PE Pipes Containing Surface Notches Subjected to Internal Pressures.*" [3] by GRI.

As proposed the language for §192.311(a) also implies that new technologies designed to address scratches and gouges in PE pipe, such as electrofusion fitting repair sleeves, would not be allowable due to the fact that PHMSA requires a repair.

AGA suggests only requiring a modified §192.311(a), which requires the removal of imperfections or damages, and removing §192.311(b) from proposed pipeline safety code language. This would allow operators to follow manufacturer recommendations and make conservative determinations on the imperfections or damages that should be removed or repaired. AGA suggests the following modification to §192.311(a):

[2] D.A. McKee, C.H. Popelar, C.J. Kuhlman, N. Brown and M.M. Mamoun. *Experimental Determination of Allowable Crack Depths in Polyethylene Pipes Subjected to Internal Pressure Loading.* 1999 International Plastic Pipe Symposium.

[3] D.A. McKee, C.H. Popelar and C.J. Kulhman. *Service Performance of Polyethylene Pipes Containing Surface Notches Subjected to Internal Pressure.* Gas Research Institute. June 2000.

> §192.311(a) Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired with a suitable electrofusion sleeve or the damaged pipe must be replaced.

<u>H2. Leak Repair Clamps</u>

AGA would like clarification on whether the additional regulation §192.720 - *Distribution systems: Leak repair,* within Subpart M – *Maintenance,* is intended to be retroactive in nature. While AGA understands PHMSA's desire to ensure that companies are following manufacturer's recommendations to not utilize mechanical leak repair clamps as permanent repair methods, AGA does not believe it is PHMSA's intent to require operators to find and locate all existing leak repair clamps already installed on plastic pipe in their system.

AGA supports a regulation encouraging operators to remove any existing mechanical leak repair clamps not meant for permanent repairs, as they are discovered in the system. However, AGA also cautions PHMSA that regulations as currently proposed may impair new technology to enter the market place. AGA suggest PHMSA modify §192.720 to require compliance after the effective date of the Final Rule and to limit the requirement to mechanical leak repair clamps. AGA suggests the following language.

> §192.720 – *Distribution systems: Leak repair*
> (1) Except as provided in paragraph (a) a mechanical leak repair clamp may not be used as a permanent repair method for plastic pipe after [INSERT EFFECTIVE DATE OF FINAL RULE].
>   (a) Mechanical leak repair clamps must be tested and qualified for permanent repair.
> (2) Upon discovery, any leak repair clamp not intended for permanent repair must be removed.

I. General Provisions

<u>I3. Storage</u>

AGA requests additional background information on PHMSA's addition of §192.67. AGA is under the impression that this new requirement is due to the adoption of ASTM D2513-09a and the extension of outdoor storage ability.

<u>I7. Valves</u>

To ensure no confusion about the need for operators to find and replace existing valves not meeting the proposed language in §192.145(f), AGA suggests the following modified language:

> §192.145(f) – Newly installed plastic valves must meet the minimum requirements stipulated in a listed specification. A valve may not be used under operating conditions

that exceed the applicable pressure and temperature ratings contained in those requirements.

III. Conclusions

In general, AGA supports most of the plastic pipe regulation updates as proposed. There are a few sections throughout the Proposed Rule where AGA encourages PHMSA to reevaluate the technical justifications. In some cases, AGA has provided suggested modifications to the regulatory language.

AGA supports the intent and concepts behind the Tracking & Traceability of pipe and components. However, AGA urges PHMSA to remove this section of the proposal from the final rulemakings. The challenges for implementation remain numerous and uncertain and can therefore not be considered non-significant at this time. Removing this portion of the proposed rule would allow PHMSA to move forward on the remainder of the items found within the Plastic Pipe Rule. The separation would also allow PHMSA to work with the appropriate stakeholders to continue the progressive conversations pertaining to Tracking & Traceability.

AGA appreciates the opportunity to comment on this proposed rule.

Respectfully submitted,

Date: July 23, 2015

AMERICAN GAS ASSOCIATION

By:

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LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 22

Responding Witness: Lonnie E. Bellar

Q-22. Refer to the direct testimony of Christopher ("Chris") M. Garrett, pages 30-32, wherein he discusses LG&E's Gas Line Tracker ("GLT").

a. Explain what LG&E uses the GLT mechanism for since the main and riser replacement programs are completed.

b. Provide the projects currently included in the GLT, and which projects are anticipated to be added before April 30, 2020.

A-22.

a. The Company has been approved for recovery of two projects in Case No. 2016-00371 for programs that are reducing risk to the system by replacing customer steel services lines and the replacement of approximately 15.5 miles of gas transmission line. Additionally, the Company recovers gas service line related costs associated with leak mitigation (replace company services) and customer service line ownership (replace and install customer service lines) along with associated expenses related to customer service lines.

b. Current projects include:
   - Gas Service Line Replacement Program - Investment only
   - First phase of the Transmission Pipeline Modernization Program - Investment only
   - Leak Mitigation (Replace Company Services) - Investment only
   - Customer Service Line ownership (Replace/Install Customer Service Lines and Customer Service Line related maintenance) - Investment and Expense

   No additional projects are anticipated to be added before April 30, 2020.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 23

Responding Witness: Lonnie E. Bellar

Q-23. Reference the Bellar testimony, p. 62 regarding the proposed dry amine treatment process to replace the current wet amine process at the Muldraugh and Magnolia compressor stations.

a. Provide the estimated remaining useful lives for the equipment used in the existing wet process.

b. Provide the estimated useful lives for the equipment to be used in the dry process.

c. Is the proposed replacement mandated by any regulations or other legal requirements? If so, provide citations and copies of same.

A-23.

a. Existing wet amine plants were originally installed between 1960 and 1965. Major components such as pressure vessels, boilers, piping, and valves have exceeded their useful life and will require replacement to maintain continued reliable and safe operation.

b. The estimated useful life of the purification equipment based on engineering design is 30 years.

c. LG&E is not aware of a regulation requiring the proposed changes.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 24

Responding Witness: Daniel K. Arbough / Adrien M. McKenzie

Q-24. Refer to the direct testimony of Adrien M. McKenzie, generally.

a. Are the Companies aware of any instance since their 2016 rate cases in which they were unable to attract the capital needed for infrastructure and reliability investments on reasonable terms due to their allowed ROE of 9.7%?

b. Although Mr. McKenzie's testimony seems to adequately address the risk a utility faces when its allowed ROE is set too low, explain, in complete detail, what risk(s) the Companies and their customers face if the Commission sets the allowed return on equity too high.

c. Are the Companies aware of any organizations that rate or rank state regulatory commissions?

d. If the response to subpart c., above, is in the affirmative, provide a discussion of how the Kentucky Commission ranks or rates in such reviews.

A-24.

a. LG&E has been able to access the debt capital markets over the past two years at interest rates consistent with its credit rating. LG&E does not directly access the equity capital markets. However, the ROE to be set in this proceeding should not be based on the Company's past ability to attract capital, but rather on what investors' expectations are for the future.

b. Under established regulatory standards, the KPSC must balance the interests of customers and a utility's shareholders by allowing an ROE that is sufficient to fairly compensate investors, enable the utility to offer a return adequate to attract new capital on reasonable terms, and maintain the utility's financial integrity. At the same time, the KPSC has the duty to protect consumers from monopolistic prices and to preserve the public interest. As the Supreme Court recognized in *Bluefield*, a utility "has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures." Thus, allowing an ROE that is excessive and exceeds the return required by investors from comparable risk opportunities would unfairly harm consumers as the prices paid for utility service would exceed the underlying costs. In addition, consistently setting the allowed ROE above the market cost of equity may lead to uneconomic capital investments by distorting the price signals provided by competitive capital markets.

c. The Company is aware of a June 25, 2018 publication from S&P Global Ratings, entitled "U.S. And Canadian Regulatory Jurisdictions Support Utilities' Credit Quality – But Some More So Than Others," which ranks Kentucky as "most credit supportive."

d. See the response to part (c).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 25

Responding Witness: Adrien M. McKenzie

Q-25. Refer to the direct testimony of Adrien M. McKenzie, page 3, wherein he cites to both the Hope and Bluefield cases.

a. Cite to the specific instances in Mr. McKenzie's testimony where he balanced the interests of investors and consumers.

A-25.

a. As discussed in Mr. McKenzie's testimony, consistent with the *Hope* and *Bluefield* decisions, an ROE that is sufficient to fairly compensate investors, enable the utility to offer a return adequate to attract new capital on reasonable terms, and maintain the utility's financial integrity provides an end-result that represents a balance between the interests of investors and consumers. Based on the evidence presented in Mr. McKenzie's testimony, he concluded that an ROE of 10.42% would fulfill this requirement.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 26

Responding Witness: Adrien M. McKenzie

Q-26. Refer to the direct testimony of Adrien M. McKenzie, page 13, wherein he notes that "Moody's recently lowered its ratings outlook for 24 utilities from 'stable' to 'negative,' and one utility from 'positive' to 'stable.'"

a. Were either of the Companies any of these 24 utilities referenced?

A-26.

a. No.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 27

Responding Witness: Adrien M. McKenzie

Q-27. Refer to the direct testimony of Adrien M. McKenzie, pages 16-18, wherein he briefly described LG&E and KU.

a. Does the fact that the Companies do not operate as a member of an RTO, all else being equal, increase or decrease their risk relative to their peers?

A-27.

a. In the course of preparing his direct testimony, Mr. McKenzie did not undertake any analyses or empirical studies to differentiate between the investment risks of utilities that operate as a member of an RTO and those that do not; nor was such a study necessary or relevant to support his recommendations and conclusions.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 28

Responding Witness: Adrien M. McKenzie

Q-28. Refer to the direct testimony of Adrien M. McKenzie, page 50 & Exhibit No. 5, page 3 of 3, wherein Mr. McKenzie provides his "DCF Cost of Equity Estimates."

a. Confirm that Mr. McKenzie excluded 13 "low" figures and only 3 "high" figures.

b. Explain the criteria used to determine which values on Exhibit No. 5 were, as Mr. McKenzie describes them, "illogical."

c. Provide page 3 of 3, including the previously excluded values.

A-28.

a. Confirmed.

b. Please refer to Mr. McKenzie's direct testimony at pages 46-50, which discussed the criteria used to evaluate the DCF results presented on Exhibit No. 5.

c. Mr. McKenzie did not prepare a version of page 3 of Exhibit No. 5 that included the highlighted values in the course of preparing his direct testimony as Mr. McKenzie does not believe that such an analysis would represent a meaningful application of the DCF model.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 29

Responding Witness: Daniel K. Arbough

Q-29. Is the forecast in the application consistent with the version used for quarterly earnings guidance and investor presentations?

a. Describe the differences.

b. Discuss the timing of the budget, long range plan and forecasts leading up to the version reflected in the application.

c. Provide any updates to forecast related to earnings guidance since the Companies' applications were filed. Any response should take into account information offered at the 2018 EEI Financial Conference to be held in San Francisco, California on Tuesday, November 13, at 10 am Pacific Standard Time.

A-29. The quarterly earnings guidance and investor presentations referenced are for PPL Corporation. LG&E and KU information is included within the Kentucky Regulated business segment in those presentations. There are some timing differences between the LG&E and KU information included in those presentations and the information included in the application.

a. The 2018 earnings guidance from the third quarter investor call and the subsequent investor presentations, including the November 13 presentation at the EEI Financial Conference, reflect actual results through the third quarter and forecasted results for the remainder of 2018. The application included actual results through June 2018 and forecasted results for the remainder of 2018. In the third quarter investor call, PPL raised its 2018 earnings guidance for its Kentucky Regulated segment by two cents per share reflecting the load-supportive temperatures experienced by LG&E and KU for much of 2018. With respect to the capital expenditures and the resulting rate base or capitalization presented for the Kentucky Regulated segment, the amounts included in this application have been updated to reflect LG&E and KU's 2019 business plan whereas the investor presentations are still based on the 2018 business plan. Changes such as removal of the advanced metering system project have been included in the application. Absent a material change, PPL generally updates these capital expenditure and rate base or capitalization numbers annually during its yearend investor call. Also, as noted in the application the forecasted information included in the application does not reflect any impact from rate case activity beyond 2018.

b. The planning process is described in my testimony in Section I starting on page 2. The process began in March this year and was completed in September.

c. See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 30

Responding Witness: Christopher M. Garrett

B. <u>Rate Base/Capitalization</u>

Q-30. Refer to the direct testimony of Christopher ("Chris") M. Garrett, pages 4-8, wherein he discusses the Companies' choice of capitalization as the measure of valuation in these matters.

a. Does the fact that both of the Companies' jurisdictional capitalizations exceed rate base play into the Companies' use of capitalization as the measure of valuation?

b. Can the Commission and intervenors expect that, should the Companies' rate base exceed capitalization in future rate proceedings, the Companies will continue using capitalization as their measure of valuation?

A-30.

a. No. The Company believes that capitalization remains the most objective measure of valuation as evidenced by the Company's use of capitalization as its valuation measure for the past 40 years. Capitalization appropriately addresses the extent to which the Company funds its working capital, consistent with the overall balance sheet approach for evaluating cash working capital in a revenue requirement calculation as discussed in the Rate Case and Audit Manual prepared by NARUC Staff Subcommittee of Accounting and Finance (Summer 2003). In LG&E's Case No. 2000-00080, the Commission recognized that capitalization is a better measure of the real cost of providing service as it is the cost of debt and equity that is reflected in the financial statements of the utility. Therefore, the Company sees no reason to change its valuation methodologies.

b. Yes. The Commission and intervenors can expect that the Companies will continue using capitalization as their measure of valuation, as evidenced by their long-standing history in prior rate case proceedings of using capitalization as their valuation method even when it fell below rate base.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 31

Responding Witness: Christopher M. Garrett

Q-31. Refer to the direct testimony of Chris M. Garrett, page 39, wherein the proposed extension of the amortization period for the Winter Storm 2009 and Wind Storm 2008 regulatory assets to June 2021 is discussed.

a. Explain why June 2021 was chosen and is reasonable.

A-31.

a. Based on the Company's recent history of filing base rate cases every other year, the Company felt it was appropriate to extend the amortization to June 2021 in an effort to mitigate a potential over-recovery.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 32

Responding Witness: Kent W. Blake

Q-32. Refer to the direct testimony of Kent W. Blake, pages 5- 6.

a. Provide the tables presented on page 6 for the period June 30, 2018, to April 30, 2020.

b. Explain why using the midpoints of two test periods to compare capital expenditures is more reasonable or representative than using the 13-month average capitalization for each test period.

c. Explain why the Companies chose to provide the capital spend using these two test-period midpoints.

A-32.

a.

Total capital spend July 1, 2018-April 30, 2020

$ millions	**KU**	**LGE**	**Total**
Generation	592	326	918
Electric Transmission	245	65	310
Electric Distribution	266	248	515
Gas Operations	-	251	251
Customer Service	30	34	64
Other	56	54	111
Total	**1,190**	**978**	**2,168**

Total capital spend not subject to recovery through mechanisms July 1, 2018-April 30, 2020

$ millions	**KU**	**LGE**	**Total**
Generation	313	177	491
Electric Transmission	245	65	310
Electric Distribution	266	248	515
Gas Operations	-	132	132
Customer Service	30	34	63
Other	56	54	111
Total	**911**	**711**	**1,622**

b. See discussion in the direct testimony of Kent W. Blake on pages 5-6. In terms of identifying capital expenditures contributing to the increase in 13-month average capitalization, use of the mid-point to mid-point between the two test years was chosen as a representative time period. The dollar amount of capital expenditures in the alternative time period requested in 32a above is relatively consistent with that of the time period chosen. However, due to the use of 13-month average capitalization in both this proceeding and the Company's prior rate case, the amounts in 32a eliminate capital expenditures prior to July 1, 2018, for which full recovery of the cost of capital was not included in the Company's last base rate case and includes certain capital expenditures through April 30, 2020, for which full recovery of the cost of capital is not being sought in this proceeding.

c. See the response to part b.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 33

Responding Witness: Elizabeth J. McFarland

Q-33. Refer to the direct testimony of Lonnie E. Bellar, page 3, wherein he mentions "[s]everal recent projects to promote solar generation."

a. Describe these recent projects.

A-33. The Companies have installed their first business solar at the Archdiocese of Louisville office on Poplar Level Road, have fully subscribed the first solar array in the solar share program, and are sharing generation data from Brown Solar through the LG&E-KU website. The Companies continue to actively seek additional opportunities to develop and provide solar energy in the Commonwealth. Each is discussed in more detail in Mr. Bellar's Testimony at pages 19, 31, and 33.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 34

Responding Witness: Lonnie E. Bellar

Q-34. Refer to the direct testimony of Lonnie E. Bellar, page 4, wherein he states, "I will present the details of the capital expenditures using the period January 1, 2018, to October 31, 2019, for the generation, transmission, distribution, customer service and gas operations in my testimony."

a. Provide the same presentation of details of capital expenditures for the same categories for the time period October 31, 2019, to April 30, 2020.

b. Provide, by project, the capital expenditures planned for the period May 1, 2019, to April 30, 2020.

A-34.

a. Details of capital expenditures for the time period October 31, 2019, to April 30, 2020 are presented below (in millions).

Generation	**KU**	**LGE**	**Total**
Outage Related Investments	$74	$25	$99
Demolition of Retired Coal Plants at Tyrone, Pineville, and Green River	$5	$4	$9
All Other	$10	$9	$19
Total	$89	$38	$127

Transmission	**KU**	**LGE**	**Total**
Transmission Proactive Replacements	$134	$32	$166
Transmission Reliability	$15	$5	$20
Transmission Expansion Planning	$31	$9	$40
Transmission Other	$23	$7	$30
Total	$89	$38	$127

Electric Distribution	**KU**	**LG&E**	**Total**
Connect New Customer	$20	$16	$36
Enhance The Network			
Distribution Automation	*$5*	*$7*	*$12*
Circuit Hardening/Reliability	*$6*	*$3*	*$9*
Transformer Contingency	*$5*	*$3*	*$8*
Other	*$12*	*$8*	*$20*
Maintain The Network	$16	$23	$39
Repair The Network	$3	$4	$7
Miscellaneous	$1	$0	$1
Total	$68	$64	$132

Customer Service

The combined Companies plan to spend a total of $13 million in non-mechanism capital investment in customer services from October 31, 2019 through April 30, 2020. This spending includes $6 million for facility and site improvements, $3 million for meters, $1 million for facility consolidations, and $3 million for all other projects.

Gas Distribution	**LG&E Total**
Connect New Customer	$2
Enhance The Network	
Bullitt County Line	*$4*
East End Reinforcement	*$0*
Elevated Pressure Upgrade	*$1*
Replace Pad Meters	*$1*
Other	*$13*
Maintain The Network	$7
Repair The Network	$0
Miscellaneous	$1
Total	$29

b. See attached.

Louisville Gas and Electric Company
Case No. 2018-00295
Question No. 34
Capital Expenditures for Generation, Transmission, Distribution, Customer Service, and Gas Operations

LGE Capital Expenditures

Project #	Project Description	Amount
00027FACL	AOC MEN/WOMENS LOCKER ROOM	300,040.40
00028FACL	AOC ASSEMBLY ROOM RENOVATION	125,084.41
00029FACL	AOC SPACE EXPANSION	1,005,772.17
00034FACL	BOC 1ST FLOOR RENOVATION LGE	884,514.08
00035FACL	South Ops Engineering Center	3,333,286.32
00036FACL	SSC ROOF REPLACEMENT	100,047.26
00053FACL	BOC AHU-7 BOC-LL MAINT AHU RM	128,936.28
00054FACL	BOC AHU-8 BOC-LL PSRT AHU RM	128,936.28
00065FACL	GAS & EL SAFETY-TRAIN BLDG EOC	4,297.26
00066FACL	BOC DCC SPACE CONVERSION LGE	884,916.45
00075FACL	BOC Elevator refurbish	338,052.28
00076FACL	Building Façade Repairs	354,777.50
00080FACL	SSC Trnsfmr Bldg Ovhd Door	15,002.02
00082FACL	Auburndale Boiler Replacement	249,986.36
00085FACL	AOC Telecom Space Expansion	175,057.36
00105FACL	KUGO Floor 1, 2 Remodel LGE	478,205.19
00114FACL	Dix Dam Replace CRAC Units LGE	10,994.05
0064FACIL	SIMP SWITCHGEAR UPG IT L	56,255.50
0064FACTL	SIMP SWITCHGEAR UPG TR L	36,003.52
119902	Clear 12/04 A&G	203,781.00
123137	LG&E POLE INSPECTION	4,959,386.21
123906LGE	BRCT6 C Inspection LGE	790,745.39
124090	MC Limestone Unld Bucket	64,480.87
124518	TC1 RECYC PUMP PIPING EBW	732,536.01
124526	TC COAL YARD BUILDING SIDING	58,129.57
126736	Manslick Substation Expansion	86,322.15
131715	N1DT Pleasure Ridge Sub-CW	2,456,235.38
132960	MC1 DCS 2019	100,000.00
132976	MC Dozer #1	2,200,000.00
132989	MC2 Relays	694,153.26
133076	GS GE Dam Impnd	37,880.10
133615LGE	TC PLT ENG/MTR RWNDS	142,522.85
133622LGE	TC LAB PURCH MONITORS	49,189.85
133627LGE	TC LAB EQUIP PURCHASES	30,337.55
133653LGE	TC SAFETY & ERT EQUIP	31,226.40
133671	EFFLUENT WATER STUDY-MC	683,999.79
133679	EFFLUENT WATER STUDY-TC LGE	195,000.00

134198	CR CNL-DLPRK 69KV	3,548,815.96
134238	DSP LIME KILN SUBSTATION	894,300.63
134898	PE Vehicle Purchases	200,000.00
136480	GS GE Test Equip Pool	71,034.56
136562	GS SL Coal Mstr Ash Anlzr LGE	106,433.25
136636	MC3 SCR Catalyst Layer 1	1,497,578.21
137039	TC1 RPLCE AIR HEATER BASKETS	1,295,127.67
137587	TC1 DCS UPGRADE	1,087,147.50
138032	IMPROVE PIPELINES	501,912.09
138395	TC1 SH FRONT PLATEN	159,592.50
138400	TC1 SH DMW REPLACE	257,388.75
139065	LGE CTR REMODEL REMOVAL	24,631.70
139682LGE	TC PREDICTIVE DEVICES MAINT	22,307.03
139721	MC 3C GSU Transformer	421,211.37
139725	TC1 REPLACE TURBINE ROOM ROOF	512,183.40
139878	MC3 TURB MISC	2,444,106.71
139880	MC1 FDWTR HTRS Phase 1	99,108.56
139889	MC3 AIR HTR BASKETS	1,466,572.59
139892	MC3 FDWTR HTRS	942,772.88
139991	TEP-CR-MIDVALLEY-FNCHVL	1,088,089.89
140014LGE	TC CT DCS UPGRADE	89,083.65
140032LGE	TC PURCHASE JLG LIFT	98,379.70
140074	DIGITAL EMS COM CHNLS-LGE-2019	38,945.43
140095	SIMP CC V_WALL RPLC-LGE-2020	689,282.00
140099	EMS OPERATOR MONITORS-LGE-2019	15,375.69
140112	ROUTINE EMS-LGE 2019	6,081.90
140342LGE	MISC TOOLS LGE	36,892.39
140440	TEP-CR-NORTH TAP-SO PARK	567,371.20
140619LGE	TC CONVEYOR BELT REPLACE	70,787.63
140654LGE	TC CBU BKT & CHAIN	223,070.25
140659LGE	TC CT LCI UPGRADE #2	118,513.22
141004	ST HELEN FACILITY	1,773,944.10
141390	Environmental Equipment LGE	17,500.00
141392	LGE FURNITURE PROJ	66,900.90
141618	Meter Shop 2019 LG&E Electric	40,000.00
142399	MC3 Gen Stator Bar Install	2,973,256.80
143591	MC CH Railroad Track 2019	170,579.90
143592	MC Material Hndlg Chutes 2019	242,996.88
143595	MC4 SCR Catalyst L1 2020	991,872.29
143601	MC3 Expansion Joints 2019	98,136.02
143603	MC Misc Equipment 2019	693,759.91
143605	MC3 DCS (2019)	1,070,929.02
143609	MC Conveyor Belts 2019	267,778.65
143611	MC Safety Equipment 2019	33,728.46
143634	MC Misc Lab Equipment 2019	62,496.82

143637	MC3 Turbine L-0 Buckets 2019	1,990,000.00
144503	GS CDM GMD Protection	21,002.83
144510	GS CDM CIP Ver 7.0 LGE	69,721.88
144530	OF Trash Racks (multi-year)	90,174.34
144531	CR7 Misc Project (multi-year)	116,117.30
144542	CR7 NGCC HGP (2020)	4,994,168.29
144782	LGE Loaned to Transmission	(2,391.85)
144869	PRESTON CITY GATE STAT	2,391,102.39
145027	LGE SECURITY EQUIPMENT 2019	70,379.69
145087	Retail Hardware LG&E 2019	99,000.00
145402	HR Cap Equip Improvmnts LGE	10,000.00
147042	MC2 Exp Joints 2020	98,156.80
147048	MC 3 and 4 Spare GSU Trans	1,428,499.05
147056	MC2 Boiler Lower Slope	2,768,487.03
147058	MC3 Econ Inlet Header	1,368,236.17
147735	FULL UPGRD EMS SWARE-LGE-2020	31,423.15
147745	SIMP V_WALL C_RPLC-LGE 2019	151,033.85
147766	EMS DBASE EXPANSION-LGE-2019	33,467.15
147795	EMS APP ENHANCEMENTS-LGE-2019	19,259.35
147802	RTU-IP TRAFFIC TO EMS-LGE-2019	59,739.61
147819	SPIR Project LGE	342,666.92
147831	Corporate Contingency-LGE	2,170,000.00
148083	OF Bridge Resurface	73,513.77
148084	OF Asphault Repl	29,298.98
148096	CR7 NGCC STG (2019)	305,382.34
148104	CR7 Annual Outage (2020)	227,105.09
148132	GS GE CV Landfill Instrum	40,745.49
148396	Prop. Tax Cap. - LGE Non-Mech	516,771.30
148469	CR DEMO - PE ONLY	9,271,000.00
148484	N-1 DIST XFMR PLAINVIEW CW	978,065.43
148490	N1DT PLAINVIEW SUB	1,393,602.81
148727	LGE SMAC 2017 PROJECT	1,415,355.92
148821	SR Floyd-Seminole 69kV	458,243.88
148822	CR Olin-Tip Top 69kV	1,758,112.44
148882	DSP TUCKER STATION	300,001.96
148884	DIST XFMR LIME KILN CW	1,415,242.79
148885	DIST XFMR LIME KILN SUB	6,257,176.19
149021LGE	TC2 TDBFP RECIRC VALVE B	32,032.58
149165	LGE SECURITY EQUIPMENT 2020	83,436.93
149336	MULD TRACK SKID LOADER	95,000.47
149344	SC CAPITAL - 2016 BP - LGE	100,000.00
149400	VINE GROVE BACKUP FEED	519,000.22
149481	Misc Retail Hardware 2020 LG&E	11,000.00
150017LGE	TC2 BURNERS (C,F ROWS)	25,487.81
150031LGE	TC ASH POND MOWERS	58,890.55

150035	TC1 UPPER ARCH REPLACEMENT	211,189.69
150052LGE	TC2 LOWER SLOPE WW REPL	173,400.56
150053LGE	TC ELECTROMECH RELAY	84,766.70
150059LGE	TC UPG COAL HAND SAMPLER	133,842.15
150064LGE	TC2 SSC TILE	74,856.44
150065LGE	TC WASTE PUMPS SLUDGE PIT	33,460.54
151000	TC1 & COMM 480V BREAK UPG	85,796.25
151006	TC2 NOX PROBE GRID	96,886.15
151010	TC1 COAL CONDUITS	128,694.38
151015	TC1 BURNERS (C,D ELEVAT)	343,185.00
151021	TC1 ELECTROMECH RELAYS	359,485.14
151249	MC Plant Fire Protection	198,291.33
151255	MC 3B GSU Transformer Install	421,211.37
151259	MC3 Field Instrumentation 2019	391,729.30
151481	DIST CAPACITORS LGE - 2019	149,797.19
151482	LEO TRANSMISSION LINE CLR	470,021.71
151483	LEO PADMOUNT SWITCHGEAR 2019	199,171.04
151484	DWNTWN NTWK VENT PRTCT REPL19	954,399.12
151485	LEO DWNTWN NTWK VAULT RPR 2019	1,135,684.95
151486	PILC 2019 LGE CABLE REPL	7,950,393.31
151496	SCM2019 LGE RPL SUB BATTERY	102,922.93
151497	SCM2019 LGE LEGACY RELAY REPL	76,051.44
151498	SCM2019 LGE REPLLGCYAIRMAG BRK	400,189.26
151499	SCM2019 LGE REPL LGCY OIL BRKR	411,873.00
151500	SCM2019 LGE REPL LEGACY RTU	109,819.57
151529	SCM2019 LGE LTC OIL FILT ADDS	32,744.76
151530	SCM2019 LGE MISC CAPITAL SUB	122,000.13
151531	SCM2019 LGE MISC NESC COMPL	54,907.01
151532	SCM2019 LGE OIL CONTAIN UPGRD	111,000.09
151534	SCM2019 LGE REPL ABB VHK MECH	57,138.30
151535	SCM2019 LGE SUB BLDNG & GND	119,000.49
151538	SCM2019 LGE WILDLIFE PROTECT	82,999.51
151544	2019 LGE TRANSFORMER REWIND	1,139,000.40
151546	LEO TOOLS AND EQUIPMENT 2019	330,322.05
151549	SCM2019 LGE TOOLS & EQUIPMENT	33,000.24
151553	URD CABLE REPL/REJUV LGE 2019	1,135,820.23
151578	MC2 Boiler Air Tips	242,894.63
151757	LGE Fence Replacements	334,351.79
151784	MC1 DCS Hardware 2020	96,188.02
151857	MC Landfill Closure 2018	272,548.54
152006LGE	TC CT EX2000 DIGITAL FE CT9	70,468.24
152007LGE	TC CT LUBE OIL PUMPS	42,326.15
152015LGE	TC CT MARK VI UPGD CT9	97,138.51
152016LGE	TC CT MARK VI UPGD CT10	96,926.88
152032LGE	TC CT HMI UPGRD	147,755.99

152055	CR7 T3K Hardware Refresh	167,671.84
152056	PR13 T3K Hardware Refresh	244,778.32
152063	TC1 REAR WW HANGER TUBES	60,597.19
152081	TC1 EXP JOINTS	354,767.49
152097LGE	TC RAT RELAYS LGE	65,891.18
152224	Clifty Creek DL1/DL2 Brkr Rpl	644,394.65
152330	MC Gypsum Dewatering Non-ECR	3,110,128.00
152417	CONV DR DEEP TO UPPER 2019	309,011.21
152419	DRILL WELLS MAG DEEP 2019	708,963.77
152423	DRILL WELLS MAG UPPER 2019	571,888.56
152424	DRILL OBVS WELLS MULD 2019	269,900.74
152425	DRILL WELLS CENTER 2019	772,683.43
152433	IR DROP COUPON MON SYS 2019	477,344.55
152439	2019 RPL VLVS CG & DIST REG FC	99,237.32
152442	2019 PURCH ELEC RECORD GAUGES	169,925.04
152446	UPG CT STA TRANSMITTERS 2018	30,292.93
152449	SECURITY CG & LRG REG STA 2019	50,317.98
152455	COOLER HOUSING/SHROUDS 2019	91,089.70
152505	MULD ENG & COMP UPGRADE	348,937.97
152507	MUL STATN & FLD WASTE STORAGE	39,242.06
152508	COMPRESSOR ENGINE AUTO EQUIP	684,972.29
152513	CANNONS LN REGU STATN 2018	300,375.75
152524	ODORANT TANK LEVEL PROBES	34,508.73
152528	INGERSOLL EXHAUST HEADERS	69,394.90
152529	H2S GAS DETECTION	55,270.13
152531	ENGINE ROOM TRANSITE SIDING	247,678.25
152532	CONTROL RM W BASEMENT	466,908.32
152534	ONLINE AMINE ANALYZER	54,216.18
152535	ENGINE ROOM OVERHANG	101,179.20
152536	ENGINE VIBRATION EQUIP	199,959.15
152553	SMALL TOOLS 2019 004060	31,458.63
152573	Manhole Structural Rep 2019	284,008.23
152583	STT Misc Project	50,697.50
152614	LGE Station Grounding	(3,933.00)
152632	LGE Coupling Capacitor Rpl	42,494.64
152639	LGE Online Monitoring Equip	241,610.90
152642	LGE Resiliency Upgrades	158,071.04
152652LGE	TC2 BOILER WW	51,197.50
152659LGE	TC2 A ID FAN OVERHAUL LGE	154,085.25
152667	TC1 BCWP OVERHAUL	121,877.58
152670	TC1 TDBFP PUMP OVERHAULS	125,876.22
152685LGE	TC2 B BFP OVERHAUL LG&E	32,845.24
152693LGE	TC OFFICE UPGRADES %	151,241.63
152711	CR Skylight-Harmony Landing	870,442.63
152769	LGE REPLACE FAILED EQ - 2019	79,571.53

152772	CR7 CT 1&2 Insulation	414,927.89
152775	A/V EQUIPMENT - 2019	155,798.01
152778	LGE FACILITY IMPROVEMENTS-2019	86,160.25
152799	LG&E FURNITURE AND CHAIRS-2019	100,756.81
152805	LG&E CARPET/FLOORING-2019	47,641.55
153002	LGE CIFI RAP	1,589,999.91
153004	LGE CEMI	786,399.90
153006	REL System Hardening LGE	3,398,160.04
153009	TC1 CEM SHELTER REPL	536,226.56
153015	Sub Exit Cable Repl LGE	1,611,595.77
153018	FAC & SITE IMPROVE LTP-LGE	101,365.00
153021	REPL FAILED EQUIP LTP-LGE	27,368.55
153024	FURN & EQUIP LTP-LGE	122,550.29
153047LGE	TC2 FINAL SH REPL*	114,549.66
153056LGE	TC IMPOUNDMENT IMPROVEMENTS	79,868.10
153065	Solar Projects - Community LGE	403,333.28
153070LGE	TC CT PEEC BATTERIES	76,187.07
153072LGE	TC FUEL HANDLING DOZER	624,596.70
153077	TC1 SCR CATALYST L2 NEW	2,254,736.93
153080LGE	TC2 SCR CATALYST L1 NEW-	578,261.11
153373	Battery Replacements - LGE	94,900.47
153561	DCC ENHANCEMENT LGE	783,554.20
153662	BULLITT CO SYSTEM REINFORCE	16,640,269.00
153884	MC3 Cooling Tower Elect Cable	743,314.21
154092	Distribution Auto LGE 2017	15,148,562.82
154095	IT Distrbution Automation LGE	559,216.48
154324	MC Flyash Silo "A" Baghouse	594,651.36
154327	MC Basement Water Piping	297,325.68
154338	MC3 Hydrogen Coolers	193,335.91
154341	MC4 Hydrogen Coolers	193,335.91
154378	MC1 & MC2 Hg Trap System	133,902.76
154379	MC1 & MC2 PM Probe	188,455.73
154383	MC4 Hg Trap System	128,961.72
154384	MC4 Hg CEMS	337,284.51
154385	MC4 PM Probe	183,522.45
154391	MC2 Fire Protection	144,754.16
154395	MC3 O2 Probes	247,771.40
154408	MC3 Control Valve Steam Chest	1,560,324.93
154415	MC1 Service Water Piping	49,554.27
154464	MC2 Turbine Room Roof Drains	183,350.84
154541	MC3 Secondary Air Meters	495,617.01
154542	MC4 Secondary Air Meters	148,662.85
154593	MC2/MC3 Boiler Room Roof Drain	644,205.63
154598	MC 1A MDBFP OVERHAUL	128,961.72
154600	MC 1B Blr Circ Pump OVERHAUL	99,201.33

154633	MC 1E Recycle Pump OVERHAUL	29,732.58
154635	MC 2A CTP OVERHAUL 2019	124,001.67
154639	MC 2B CTP OVERHAUL 2020	29,732.58
154640	MC 2B MDBFP OVERHAUL 2020	29,732.58
154642	MC 2C BCP OVERHAUL 2019	24,777.15
154644	MC 2F Recyc Pump OVERHAUL 2020	29,732.58
154646	MC 3A Recyc Pump OVERHAUL 2019	123,978.46
154648	MC 3B Recyc Pump OVERHAUL 2019	123,978.46
154657	MC 4D Recyc Pump OVERHAUL 2019	123,978.46
154658	MC 4E Recyc Pump OVERHAUL 2022	123,978.46
154659	MC3 TDBFP OVERHAUL 2019	219,193.18
154708	TC1 LOWER FURNACE WW REPL-	1,276,740.00
154729LGE	TC COAL CONVEYOR VFD UPGD-	45,952.47
154738	TC1 BATTERY REPLACEMENTS	168,592.50
154744LGE	TC2 COOLING TOWER PUMP OH-	18,239.62
154753	TC VEHICLES	105,243.40
154759LGE	TC LED LIGHTING-	68,928.71
154761	TC1 BOILER ROOF EXHAUSTERS	53,022.08
154762LGE	TC HVAC UPGD	26,511.04
154792LGE	TC CT WAREHOUSE-	337,552.46
154831	CR7 UV LIGHTING	43,655.55
154833	CR7 EQ OVERHAUL	164,619.31
154838	PR12 H2 Cooler	69,375.99
155077LGE	TC INSIGHT CM VIB MONITOR-	11,153.51
155124	GS GenEng MHM Software	37,000.00
155127	GS GenEng Tsfrmer Protection	133,457.98
155144LGE	BRCT7 Gen Prot Relay Upgr-LGE	29,415.24
155292	LEO PADMOUNT SWITCHGEAR 2020	100,041.41
155313	SCM2019 LGE TXFMR TOOLS	14,999.46
155315	LEO TOOLS AND EQUIPMENT 2020	79,828.60
155340	Air Compressor-LEO	29,598.75
155352	Manhole Structural Rep 2020	148,462.74
155359	DWNTWN NTWK VAULT RPR 2020	580,680.56
155361	DWNTWN NTWK VENT PRTCT 2020	479,809.74
155363	PILC 2020 LGE CABLE REPL	3,907,318.11
155365	URD CABLE REPL/REJUV LGE 2020	560,422.40
155386	N1DT Pleasure Ridge Sub	5,286,724.72
155396	MC1 Air Heater Baskets 2019	297,325.68
155418	MC3 Boiler Extended Arch Inst	2,576,822.56
155443LGE	TC F COAL CONV GALLERY REBLD-	845,495.04
155529	MV-90 Daily Read LG&E	114,096.55
155558LGE	TC2 BOILER WATER WALL 2020-	320,288.16
155651LGE	TC2 EXPANSION JOINTS 2020-	111,465.29
155659LGE	TC2 BURNER B,E ROWS 2020-	46,727.20
156464	INSTALL HEAT AT BOC	2,000,032.82

156485	CANAL DEMOLITION	200,000.00
156518	TEP-TC Reactors at TCSW	2,287,935.84
156527	SO Exit Ckt Cable Replacement	810,105.04
156660	MC 1A CWP OVERHAUL 2019	178,562.38
156664	MC 3B Mill Gearbox OVERHAUL 22	49,554.27
156666	MC4 Clg Twr Electric Cable	743,731.65
156718	MC3 SCR Roofing	346,879.98
156721	MC4 Dearator Room Roof	29,732.58
156722	MC4 SCR Roofing	346,879.98
156723	MC CH Diesel Fuel Tank	84,293.31
156739	MC3 Lower IR Panels	852,333.62
156753	MC4 SH Outlet 2020	1,381,630.48
156783	LGE Spare Transformer	28,593.83
156786	MC PAC Upgrade	59,465.14
156788	MC2 Precipitator	842,816.09
156789	MC3 Precipitator	891,977.02
156825LGE	TC MOORING CELL REFURB-	159,736.20
156830LGE	TC MATERIAL HDLG STRUCT UPGD-	99,835.13
156834LGE	TC2 WESP DRAIN PIPING-	29,724.08
156836LGE	TC DCS SIMULATOR-	894,021.96
156838LGE	TC PLC CONVERSION-	199,670.25
156846LGE	TC DCS METERING UPGD-	39,934.05
156848LGE	TC MATERIAL HAND OFFICE-	33,460.54
156850LGE	TC STACKER RECLAIM OH-	232,228.33
156909	PR13 SFC Switch Cab	114,211.54
156930	TC1 FRONT RH BEN REP	319,185.00
156931	TC1 SCANNER AIR FAN UPGRADE	51,477.75
156932	TC1 SB DRAIN PIPING OVERHAUL	76,796.25
156934	TC1 WALLBLOWER UPGRADE	38,398.13
156964	TC1 SDRS ME REMOVAL	115,194.38
156965	TC1 SDRS DP LEVEL TRANSMITTERS	43,470.10
156978	TC1 HEATER CONTROLS UPGD	257,388.75
156980LGE	TC INVERTER UPG-	20,057.70
157031	SCM2020 LGE LEGACY RELAY REPL	18,303.20
157032	SCM2020 LGE LEGACY AIR MAG BRK	15,315.30
157036	SCM2020 LGE REPL LGCY OIL BRKR	17,503.20
157038	SCM2020 LGE REPL ABB VHK MECH	16,422.09
157051	SCM2020 LGE CAP&PIN INSUL UPGD	167,898.46
157060	SCM2020 LGE LTC OIL FILT ADDS	24,465.52
157074	TC1 IA COMP OH	428,981.25
157075LGE	TC2 HA COMP OH-	20,020.36
157115LGE	TC CRITICAL HEAT UPGD*	79,868.10
157118LGE	TC GROUND FLR WATER MGMT-	29,950.54
157131	CR7 HVAC Controls Upgrade	20,528.16
157143	CR7 Ovation Serial Card Conv	7,631.37

157148	PR11 Battery Replacement	9,910.85
157150LGE	TC COAL HAND BUILD ROOF RPL	23,960.43
157153	REL Conestoga Motors	96,734.35
157186	PR13 Truck	13,131.88
157239	MC Ammonia Fogging System	325,000.00
157246	TC1 MDBFP COOLER ADD	107,245.31
157261LGE	BRCT 6&7 SFC Controls Upgr-LGE	302,137.64
157263LGE	BRCT6 AVR Upgrade - LGE	75,485.59
157265LGE	BRCT7 AVR Upgrade - LGE	75,485.59
157280	STT Pig Runs	50,697.50
157281	STT Hydraulic Fusion	30,418.50
157283	STT ITS Customization	202,790.00
157285	STT Equip Simulators-GL	76,046.25
157286LGE	STT Valve Mnt Equ LGE	28,137.11
157288LG	STT Elec Cont Stat LGE	56,257.58
157295LGE	TC CT MULTILIN RELAY UPGD-	190,467.68
157297LGE	TC CT COMPRESS BLEED VLV UP%G	84,652.30
157313	DSP N1DT Pleasure Ridge	133,250.33
157368	STT Air Compressor	22,306.90
157369	STT Trng Equip Trl	20,279.00
157470CR	CR GS SL CCR WELL MONITOR 2019	48,275.44
157471CR	CR GS SL CCR WELL MONITOR 2020	76,700.20
157552	Adams Street Redevelopment	448,666.06
157566	LEO Trailer Mounted Pump-2019	44,990.10
157575	SIO-SUB OIL BREAKERS	918,918.82
157578	SIO-RELAY REPLACEMENT LGE	3,333,655.23
157584	SIO-LED ST LIGHT CONV-LGE	0.00
157602	DSP DEL PARK TO CANAL	732,976.39
157611	LGE HW/SW Asset Mgmt 2019	164,600.01
157615	Purchase Garage Equip 2019	45,197.08
157649	Bluelick Rd PBWK	1,133,746.57
157666	SCM2019 TOOLS & EQUIP 003560	12,000.52
157696	Floyd-Seminole 69KV SR	109,527.25
157697	Canal-Del Park 69KV SR	856,117.39
157747	MC2 Feeders & Outlet Hoppers	660,000.00
157779LGE	TC2 RH ATTEMPERATORS-	177,319.16
157785	TC1 TURBINE VALVE UPGRADE	343,185.00
157813LGE	TC CT GAS METER-	317,446.13
157845	Mobile Capacitor Bank-LG&E	755,555.52
157892	Smart Cities LG&E 2019	44,000.00
157894	EE Business Dvlp LG&E 2019	29,333.20
157897	EE Business Dvlp LG&E 2020	14,666.80
158018	Mobile Control House- LGE	55,613.52
158032	MC FLY ASH BARGE LOADING	5,950,000.00
158125	TC1 HRH ELBOW 2019	1,211,943.75

158158	SPIR Mill Creek-Northside IN	555,292.93
162174	SCM2019 LGE LEGACY ARRST REPL	64,999.42
163012	SIO Fuse Savings LGE	349,999.56
163014	SIO Rel LGE UG FCI Install	1,600,759.49
165001	TC1 DIVISION PANEL REPLAC	407,532.19
406000002	Small Tools 2020 004060	22,679.00
406000004	REPLACE PAD METERS 2019	1,271,568.71
406000005	REPLACE PAD METERS 2020	379,616.29
406000021	UPGRADE ELEVATED PRESSURE 19	2,345,255.86
406000022	UPGRADE ELEVATED PRESSURE 20	557,972.94
406000030	Bluelick Rd KYTC Relocation	1,413,624.87
406000034	Nelson Co Reinforcement	31,618.50
406000045	Blankenbaker & Ellingsworth	98,388.06
406000046	River Road reinforcement - 1	168,310.62
406000047	River Road reinforcement - 2	85,497.72
406000048	Regulator Assemblies 2019	683,238.85
406000052	Regulator Assemblies 2020	149,953.00
406000053	LaGrange Distr Reinforcement	56,697.50
419000002	Small Tools 2020 004190	59,721.37
419000005	Small Tools 2019 004190	116,000.36
419000006	Equipment - backhoe 2020	120,198.70
445000001	SMALL TOOLS 2019	14,966.09
447000001	Doe Run Storage Piggability	847,283.77
447000002	Muld Station Control Rm Repl	59,000.12
447000006	Mul Station Pipe Repl 2019	1,558,819.69
447000022	Muldraugh Amine Replacement	3,095,959.90
447000030	Eng & Compr Cooling Sys Upg	62,007.36
447500002	Install Cntrl Vlvs Wells 2019	311,307.56
447500003	Install Cntrl Vlvs Wells 2020	11,849.22
447500004	CONV DR DEEP TO UPPER 2020	2,955.38
447500007	DRILL WELLS CENTER 2020	12,060.62
448000005	Mag Field Int Corrosion Mit	47,533.36
448000011	Magnolia Paving	83,262.05
448000014	Purchase CNG trucks 2019	25,166.90
448000015	Storage Field Barricades 2019	49,758.13
448000018	Storage Field Trunkline Mod	52,735.65
448000019	Magnolia Distribution	207,467.43
448000022	Magnolia Engine Room Floor	34,086.58
448000024	Small Tools 2020 004480	4,535.80
448000027	Small Tools 2019 004480	37,750.35
448000029	H2S Scavenger Upgrades	366,578.75
448000030	Magnolia Amine Replaccement	7,068,400.73
448000031	Mag Fld Int Corr Mit 2020	32,760.27
450000008	Small Tools 2020 004500	2,107.90
450000010	Small Tools 2019 004500	27,402.70

450000017	Moisture Analyzer Eq at CG	92,204.38
451000002	Small Tools 2019 004510	29,510.60
451000015	Gas Control Radios	182,333.35
460000003	Small Tools 2019 004600	15,000.06
CACMIT445	AC_MITIGATION	479,565.42
CCAPAC451	GAS REG CAPACITY PRO	600,012.37
CCAPR340	Capital CAP/REG/RECL - 003400	1,986,754.41
CCGUPG451	UPGR FACIL CG STATION 2017	50,371.63
CCOCNT451	RET/REPL CONTR CG STA 2017	59,274.43
CCPIMP445	CP IMPRESSED CUR SYS IMPROVE	32,994.55
CDEFEQ447	MULDR FAC IMP/EQ REPLACE	174,701.23
CDEFEQ448	MAG FAC IMP/EQ REPL	150,411.15
CEBREG451	PURCHASE REGULATORS EXIST CUST	25,106.90
CEMTR134	LGE Electric Meters - 001340	742,706.65
CFTCUS450	FT CUSTOMER CONVERSIONS	89,824.86
CGME406	NB Gas Main Ext - 004060	2,206,367.39
CGMTR134	LGE Gas Meters - 001340	3,844,218.94
CHPSRV451	COMM HIGH PRES GAS SRV UPGR 17	999,301.08
CNBCD340O	NB Comm OH - 003400	3,451,037.19
CNBCD340U	NB Comm UG - 003400	5,686,081.79
CNBGS419	NB Gas Services - 004190	1,769,552.77
CNBRD340O	NB Resid OH - 003400	1,949,381.61
CNBRD341U	NB Resid UG - 003410	5,861,967.27
CNBREG451	PURCH REGULATORS - 004510	89,585.75
CNBSV340O	NB Elect Serv OH - 003400	691,044.08
CNBSV340U	NB Elect Serv UG - 003400	2,046,567.03
CNBVLT343	NB Network Vaults - 003430	1,604,930.86
CPBWK340	El Public Works - 003400	1,698,692.37
CPBWK406G	Gas Public Works - 004060	1,394,875.67
CPLUG4475	PLUG GAS STOR WELLS COR CASE	841,808.11
CRCST340	Cust Requested - 003400	327,721.76
CRCST406G	Cust Requested - 004060	820.58
CRDCBL340	Repl Defective Cable - 003400	1,231,010.64
CRDD340O	Capital Rep Def OH - 003400	4,196,426.31
CRDD340U	Capital Rep Def UG - 003400	839,925.47
CREGFC451	GAS REG FAC UPGRADE BLKT 2017	639,692.59
CREGST451	UPGR FACIL DIST REG STATIONS	50,271.62
CRELD340	Capital Reliability - 003400	481,483.99
CRELI4475	RELINE GAS STORAGE WELLS 2016	575,332.28
CRPOLE340	Pole Repair/Replace - 003400	4,807,414.89
CRSTLT332	Repair Street Lights - 003320	3,771,513.27
CSTATN447	MULD STATION BLKT	599,844.97
CSTATN448	MAGNOLIA STATION BLKT	338,064.50
CSTLT332	NB Street Lights - 003320	2,323,121.59
CSTOR447	MULD STOR FIELD/TRANS BLKT	1,143,583.60

CSTOR448	MAG STOR FIELD/TRANS BLKT	646,915.46
CSTRMLGE	Cap LGE Major Storms	1,680,137.72
CSYSEN340	Sys Enh - 003400	1,049,500.61
CSYSEN406	Sys Enh - 004060	777,830.82
CTBRD340O	Cap Trouble Orders OH - 003400	3,485,078.84
CTBRD340U	Cap Trouble Orders UG - 003400	1,801,064.45
CTBRD419	Cap Trbl Orders Gas - 004190	220,989.13
CTPD340	Capital Thrd Party - 003400	895,668.08
CTPD419	Capital Thrd Party - 004190	159,137.96
CVLT343	Capital Network Vlts - 003430	1,356,775.69
CXFRM311	LGE Line Transformers	6,749,643.58
CXFRM340	NB Transformers - 003400	672,926.80
IT0101L	Smallworld GIS Upgr-LGE17-19	2,764,249.96
IT0113CG	TC Plant Alt Transport-LGE17	215,000.00
IT0225L	FERC Form 1 Tool Repl-LGE18-19	26,000.00
IT0235L	ITSM CIP/AIM-LGE18-19	39,000.00
IT0242L	Megastar & DVM MW Repl-LGE18	49,400.00
IT0246L	Mobile Dispatch Enh-LGE19-20	481,317.66
IT0294L	Upgrade Quest Server-LGE19	79,736.34
IT0301L	Rep ASTRO Spectra Yr 1/3-LGE19	72,322.52
IT0302L	Rep ASTRO Spectra Yr 2/3-LGE20	317,200.00
IT0305L	Repl Quant Repeat Yr 1/2-LGE19	33,800.00
IT0306L	Repl Quantar Repeat 2/2-LGE20	421,200.00
IT0329L	Lockout/Tagout Replace-LGE18	134,646.64
IT0333L	Cst Rel Mgmt Maj Acts-LGE18-19	105,600.12
IT0337CG	Barcode Gas Mat Steel-LGE18-19	40,000.00
IT0350L	Business Offices Kiosks-LGE19	39,600.00
IT0403L	Access Switch Rotation-LGE19	266,047.00
IT0404L	Analog Sunset-LGE19	156,000.00
IT0407L	Bill Design Tool Upg-LGE20	33,000.00
IT0408L	Bulk Power & Env Systems-LGE19	83,200.00
IT0412L	CIP Compl Tools - Year 9-LGE19	84,240.00
IT0413L	Compliance Infra Year 9-LGE19	173,891.60
IT0417L	Core Network Infra-LGE19	78,000.00
IT0419L	Corp Web Redesign-LGE19-20	46,800.00
IT0422L	Data Domain Entrprs Ref-LGE19	312,000.00
IT0425L	EMS CIP-LGE19	55,000.00
IT0427L	Endpoint Protection-LGE19	2,600.00
IT0428L	FieldNet SoftwareUpgr-LGE19	44,000.00
IT0432L	IT Sec & IP Labs Enhance-LGE19	17,334.72
IT0433L	IT Security Infras Ref-LGE19	55,467.36
IT0434L	LOAD -vendor upgrade-LGE19	63,800.00
IT0438L	Maximo Licenses-LGE19	57,200.00
IT0440L	Microsoft Lic True-up-LGE19	52,000.00
IT0441L	Mbl & Wrkst Lic True-up-LGE19	29,640.00

IT0443L	Mobile Radio-LGE19	75,400.00
IT0444L	Monitor Replacement-LGE19	40,560.00
IT0445L	MR Hardware-LGE19	22,000.00
IT0446L	Multi-Functional Devices-LGE19	15,600.00
IT0448L	Network Access Devices-LGE19	64,740.00
IT0449L	Network Access Gateways-LGE19	26,000.00
IT0450L	Network Management -LGE19	19,500.00
IT0451L	Network Test Equipment-LGE19	46,280.00
IT0452L	Oracle NMS Enhance-LGE20	44,000.00
IT0454L	Outside Cable Plant -LGE19	122,200.00
IT0456L	PeopleSoft Tools Enhance-LGE19	74,275.71
IT0457L	Personal Prod Growth-LGE19	52,000.00
IT0458L	PowerPlan Upgrade-LGE19-20	1,187,953.31
IT0463L	SAP CRM/ECC Enh/SrvcPack-LGE19	87,047.20
IT0466L	Sec Infra Enhancement-LGE19	52,000.00
IT0467L	Server Capacity Expan-LGE19	32,734.52
IT0469L	LogRhythm (CIP)-LGE19	54,600.00
IT0470L	LogRhythm (Corp)-LGE19	54,600.00
IT0473L	Site Security Improve-LGE19	22,360.00
IT0475L	StackVision Upgrade-LGE19	88,000.00
IT0477L	Tech Refesh desk/lap-LGE19	922,686.49
IT0479L	Telecom Site Renov-LGE19	43,160.00
IT0480L	Time and Labor Upgr-LGE19-21	649,652.87
IT0481L	TOA-LGE19	41,800.00
IT0483L	TRODS-LGE19	47,520.00
IT0486L	Voice Infra Expansion-LGE19	49,240.10
IT0488L	Vulnerability Scanning-LGE19	69,288.97
IT0489L	Wireless Buildout-LGE19	52,000.00
IT0490L	Repl Simulca Infr Yr 1/2-LGE19	998,288.05
IT0493L	Tripwire Repl for LID-LGE19	39,000.00
IT0494L	VERBA Major Upgrade-LGE19	83,200.00
IT0495L	Contractor Mgmt Upgrades-LGE19	77,000.00
IT0496L	ESP Virt Win Servers-LGE19	182,000.00
IT0497L	EACM Infrastructure Refr-LGE19	86,439.04
IT0498L	DB Refresh-LGE19	52,000.00
IT0499L	Windows 10 CBB upgrade-LGE19	136,766.64
IT0500L	SCCM Upgrades-LGE19	29,120.00
IT0501L	Ivanti AppSense Env Mgr -LGE19	39,707.20
IT0506L	Low Inc Asst Agency Prtl-LGE19	22,000.00
IT0507L	iPad Refresh Project-LGE19	48,829.14
IT0508L	SOA Middleware Upgrade-LGE19	67,600.00
IT0509L	Upgr OpenText Capt Cntr-LGE19	83,200.00
IT0511L	Trns Lnes Wk Mgmt Upg-LGE19-20	262,850.48
IT0512L	DACS Repl Prov/Mon Sys-LGE19	62,920.00
IT0513L	DACS Equip Repl (Yr1of3)-LGE19	166,400.00

IT0514L	DACS Equip Repl (Yr2of3)-LGE20	41,600.00
IT0517L	OpenText for Acct Recons-LGE19	39,000.00
IT0518L	Drawing Mgmt System-LGE19	92,400.00
IT0519L	Insight CM Upgrade-LGE19	13,200.00
IT0520L	Maximo Upg - Reporting-LGE19	143,000.00
IT0521L	BI Rpt Mgration SSRS Nat-LGE19	83,200.00
IT0522L	Plnt Mobile RO- EW Brown-LGE19	22,000.00
IT0523L	Plnt Mble RO- Mill Creek-LGE19	110,000.00
IT0524L	Ld Rsrch&Cust Seg DtaMod-LGE19	39,600.00
IT0525L	Hyperion Upgrade-LGE19	18,200.00
IT0526L	Exp Reimburse Repl (PtP)-LGE19	244,399.93
IT0527L	HR Interview Builder-LGE19	10,000.00
IT0528L	LifeIns&Retire Frms/Prtl-LGE19	62,500.00
IT0529L	Trans BREC Trnsprt IC-LGE19	39,000.00
IT0531L	Qradar Pckt Capt Crp/CIP-LGE19	249,326.07
IT0532L	UC&C/CUCM Major Upgrade-LGE19	41,600.00
IT0533L	Aspect EWrkfce App Upg-LGE19	39,600.00
IT0534L	CommSlr- Auto EnrollFee-LGE19	8,800.00
IT0535L	Expnd Pymt/Cust Srvc Opt-LGE19	11,000.00
IT0536L	Gas Meter Sampling Imprv-LGE19	88,000.00
IT0537CG	Gas Strg - Maximo to ARM-LGE19	300,000.00
IT0538L	EACM Virtual Infra (CIP)-LGE19	91,000.00
IT0540L	Windows 10 SW Upg EMS-LGE19	51,589.04
IT0541L	Passive Disc Vuln ID-LGE19	83,200.00
IT0542L	Data Classification Enh-LGE19	104,000.00
IT0543L	Inventory Mgmt Expansion-LGE19	130,000.00
IT0546L	UDP redirect Solarwinds-LGE19	26,000.00
IT0547L	Virt Reality Train POC-LGE19	6,600.00
IT0548L	Centrify Rp CyberArk Enh-LGE19	109,200.00
IT0549L	Computing Infra Expans-LGE19	104,000.00
IT0550L	Computing Infra Upg-LGE19	279,178.79
IT0551L	Data Center Facility Upg-LGE19	72,800.00
IT0552L	Enterprise GIS Enhments-LGE19	176,000.00
IT0553L	WMS Post Implement Mods-LGE19	61,600.00
IT0554L	IRAS PIM Post Impl Mods-LGE19	61,600.00
IT0555L	EDO Mobile Post Impl Mod-LGE19	61,600.00
IT0556L	DMZ VM Infrastructure-LGE19	4,160.00
IT0557L	Corporate RPA-LGE19	208,000.00
IT0558L	Bill Int Gas Trns Aut-LGE19-20	132,000.00
IT0559L	Genetec HW Upgrade-LGE19-20	110,000.00
IT0560L	Cust Not Expand/Repl-LGE19-20	211,818.80
IT0561L	MAM Enhments-LGE19-20	61,600.00
IT0562L	ABB Upg/iPad Depl FS-LGE19-20	319,000.00
IT0563L	RPA for Rev Integrity-LGE19-20	110,000.00
IT0564CG	Gas Operator Qual App-LGE19-20	646,935.77

IT0565CG	Strg Intgrty Mgmt App-LGE19-20	1,072,668.72
IT0568L	Data Analytics (SIO)-LGE19	343,200.00
IT0569L	Enterprise GIS-Phase2-LGE20-21	861,468.43
IT0604L	Avaya-Route&Rpt Upg-LGE19-20	357,866.47
IT0606L	Bulk Power & Env Systems-LGE20	15,600.00
IT0609L	Call Recording Upgr-LGE20-21	131,623.85
IT0610L	Centrify Licensing-LGE20	10,400.00
IT0612L	CIP Compl Tools - Yr 10-LGE20	45,760.00
IT0613L	Citrix XenDesk Maj Upgr-LGE20	43,836.00
IT0614L	Citrix XenMobile Upgrade-LGE20	15,823.08
IT0615L	CIP Compl Infra - Yr 10-LGE20	84,836.84
IT0618L	Constellation MW Rplmnt-LGE20	46,800.00
IT0627L	IT Sec Infrast Enhance-LGE20	12,959.16
IT0628L	ITSM Upgrade-LGE20	13,000.00
IT0632L	Microsoft EA-LGE20	260,000.00
IT0633L	Microsoft Lic True-up-LGE20	26,000.00
IT0634L	Mbl & Wrkst Lic True-up-LGE20	6,240.00
IT0636L	Mobile Radio-LGE20	28,600.00
IT0637L	Monitor Replacement-LGE20	8,840.00
IT0644L	Ntwrk Acc Dev&Site Infra-LGE20	13,260.00
IT0647L	Network Test Equipment-LGE20	18,720.00
IT0649L	Outside Cable Plant -LGE20	31,200.00
IT0651L	Pers Product Grow & Ref-LGE20	20,800.00
IT0656L	Router Upgrade Project-LGE20	104,000.00
IT0661L	Ser Cap Expan and Rel-LGE20	11,466.52
IT0668L	Site Security Improve-LGE20	3,640.00
IT0671L	Tech Refesh desk/lap-LGE20	586,134.60
IT0672L	Telecom Site Ren-LGE20	8,840.00
IT0673L	TOA Upgrade-LGE20	4,400.00
IT0674L	TRODS-LGE20	11,880.00
IT0675L	Truepoint MW Replacement-LGE20	31,200.00
IT0680L	Voice Infra Expansion-LGE20	31,033.51
IT0681L	Wireless Buildout-LGE20	52,000.00
IT0682L	SCADA Radio Refrsh Yr1/3-LGE20	5,200.00
IT0687L	EMC TLA Renewal-LGE20	2,340,000.00
IT0688L	BI Upgrade-LGE19	114,400.00
IT0689L	Safety Dashboard Enhance-LGE20	19,800.00
IT0690L	Aligne Upgrade-LGE20	39,600.00
IT0693L	DB Refresh-LGE20	26,000.00
IT0694L	Windows 10 CBB Upgrade-LGE20	68,375.60
IT0695L	SCCM Upgrades-LGE20	12,480.00
IT0696L	RSA Appliance Upgrade-LGE20	130,000.00
IT0697L	Replace ACS Servers-LGE20	26,000.00
IT0701L	Trans Lines Mobile Insp-LGE20	33,000.00
IT0705L	iPad Refresh Project-LGE20	25,956.92

IT0708L	My Acct Repl/Enhance-LGE19-20	337,747.19
IT0710L	SOA Middleware Upgrade-LGE20	10,400.00
IT0711L	CA API Mgmt Gateway Upg-LGE20	39,000.00
IT0712L	BI Rpting Aligne Fuels-LGE20	13,200.00
IT0713L	Enterprise GIS Enhance-LGE20	8,800.00
IT0715L	OpenTxt for Envrn Affrs-LGE20	22,000.00
IT0716L	UC&C/CUCM Major Upgrade-LGE20	10,400.00
IT0718L	Virtual Reality Implment-LGE20	110,000.00
IT0720L	Computing Infra Upgrade-LGE20	132,794.56
IT0722L	Data Center Facility Upg-LGE20	31,200.00
IT0723L	Corporate RPA-LGE20	52,000.00
IT0724L	SAP Hana 2 Upgrade-LGE20-21	3,876.51
IT0726L	Data Analytics (SIO)-LGE20	72,800.00
IT0904L	Rev Collect Transcentra-LGE20	52,431.88
IT1016L	KY SDN Impl (Phase 1)-LGE19	130,000.00
IT1019L	NPM Tech Refr (Netscout)-LGE20	104,000.00
IT1067L	SONET Repl Prov/Mon Sys-LGE19	62,920.00
IT1086L	SONET Equip Repl Yr 1/4-LGE19	324,456.61
IT1087L	SONET Equip Repl Yr 2/4-LGE20	77,148.30
L8-2019	Storm Damage T-Line LGE 2019	74,259.52
L8-2020	Storm Damage T-Line LGE 2020	38,151.24
L9-2019	Priority Repl T-Lines LGE 2019	843,467.00
LARM-2019	Priority Repl X-Arms LGE 2019	95,239.52
LARM-2020	Priority Repl X-Arms LGE 2020	48,535.97
LI-000037	PR CR Switching-Shively	148,289.26
LI-000062	REL Mt. Washington RECC	108,994.56
LI-000088	TEP-CR-Ford-Freys Hill	1,716,693.32
LI-000090	TEP-MOT-Skylight-Harmony Ldg	4,167.19
LINS-2019	Priority Repl Insltrs LGE 2019	52,494.58
LINS-2020	Priority Repl Insltrs LGE 2020	20,380.64
LOTFAIL19	LGE-OtherFail-2019	292,209.78
LOTFAIL20	LGE-OtherFail-2020	166,666.65
LOTH-2019	Priority Repl Other LGE 2019	105,173.35
LOTH-2020	Priority Repl Other LGE 2020	54,092.56
LOTPR19	LG&E Other Prot Blanket 2019	40,285.08
LRTU-20	LGE RTU Replacements-20	291,262.20
LTPGENLG	Other LTP Gen Projects LGE	112,500.00
SU-000029	PGG-Clifton GG Audit/Rmdiation	228,285.28
SU-000032	PGG-Madison GG Audit/Rmdiation	133,333.36
SU-000041	PBR-Algonquin PIN PRLY	213,609.77
SU-000063	PRLY-Grady-Paddys Run (6633)	230,080.50
SU-000077	PRLY-Aiken-Oxmoor (6650)	236,545.96
SU-000102	PBR Ashbttm-Cane Rn Swtch 3833	48,091.26
SU-000131	PR Flyd - Lcst - Simnole 6647	180,342.88
SU-000132	PR Ashbottom - Kenwood (6649)	23,988.62

SU-000133	PR Applnc Prk-Ash Bottom 3836	48,091.26
SU-000137	PR Breckenridge-Ethel (3872)	160,000.00
SU-000141	PR Clifton-Hillcrest (6628)	23,988.62
SU-000142	PR Ford-Freys Hill (6659)	79,962.08
SU-000171	PRTU FARNSLEY	100,000.00
SU-000172	PRTU SEMINOLE	100,000.00
SU-000261	REL Jeffersontown ALT 4 SU	1,680,992.02
SU-000271	PGG-Seminole GG	166,640.00
SU-000275	PDFR CRS	100,000.00
SU-000279	PDFR Middletown	100,000.00
SU-000280	PDFR Ethel	299,776.62
SU-000292	REL-Centerfield DFR	148,000.00
SU-000293	PBR- Fern Valley PIN PRLY RTU	607,868.26
SU-000294	PBR-Magazine PRLY PIR PAR	573,868.50
SU-000299	PRLY-AS-CRS 3832	92,419.64
SU-000301	PRLY-BG-TA 6651	92,419.64
SU-000335	PPLC-CP-3850 DCB-2-LGE	144,792.08
SU-000336	PRLY-BY-HB 3891	92,419.64
SU-000337	PRLY-CY-HI 6663	92,419.64
SU-000338	PRLY-CF-CW 6686	92,419.64
SU-000346	River Rd Hwy Relo-S	598,588.16
SU-000347	TEP-BL 345/161kV Transf. Repl	17,934.02
SU-000356	REL-CW-686 to Breaker	245,281.72
SU-000357	REL-DX-812 to Breaker	271,205.76
SU-000358	REL-HN-859 to Breaker	337,827.42
SU-000359	REL-MG-859 to Breaker	317,071.56
SU-000360	REL-OK-876 to Breaker	69,895.33
SU-000361	REL-PL-839 to Breaker	81,561.15
SU-000362	REL-TE-678 to Breaker	359,090.42
SU-000367	PBR-Nachand (1) BKR	138,750.63
SU-000368	PBR-Highland (2) BKR	277,501.04
SU-000369	PBR-Hancock (1) BKR	192,647.26
SU-000370	PBR-Canal (11) BKR (PIN)	552,175.64
SU-000402	PPLC-Mill Creek 3857 DCB	40,907.74
SU-000403	PPLC-Knob Creek 3857 DCB	65,735.12
TMPMAGRC	TMP: Mag 16 & 20 Road Crossing	396,588.23
TMPMCR	TMP: Mill Creek Replacement	2,668,895.21
TMPWKA	TMP: WK A 20" Standardization	671,776.55
TMPWKB	TMP: WK B 20" Standardization	8,938,455.67
Grand Total		**388,998,473.69**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 35

Responding Witness: Lonnie E. Bellar

Q-35. Refer to the direct testimony of Lonnie E. Bellar, pages 16-17, wherein he describes the planned demolition of retired coal-fired generating units at several locations.

a. Has the Commission previously approved the demolition of these units?

b. If the response to 12 (a), above, is in the affirmative, provide the Case Nos. in which Commission approval was received.

c. If the response to 12 (a), above, is in the negative, explain why the Companies have not yet sought Commission approval for each planned demolition.

A-35.

a. No, the Companies have not sought approval from the Commission for demolition of retired generation plant.

b. Not applicable.

c. The Companies informed the Commission of demolition projects at Paddy's Run, Cane Run, and Green River in Paul Thompson's testimony in the 2016 rate case proceedings. The Companies did not seek a Certificate of Public Convenience and Necessity ("CPCN") for these projects in 2016 and have not sought one here. Demolition of retired plant does not involve construction of new facilities within the purview of KRS 278.020. No provision of KRS Chapter 278 or Public Service Commission regulation expressly requires a utility to obtain Commission approval prior to the demolition of a utility facility. The Companies are not aware of any standing Commission Order requiring either Company to obtain such approval.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 36

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-36. Refer to the direct testimony of Lonnie E. Bellar, page 17, wherein he discusses a \$20.8 million capital project to replace an existing gas transmission line with a new line that "will be placed underneath the riverbed."

a. Did the Companies request and receive a CPCN for this project?

b. Provide the cost-benefit analysis conducted by the Companies to determine the efficacy of this project.

c. Provide the expected remaining service life of the "Brown CT units."

d. Is the replacement of the parapet wall of Dix Dam included in the referenced project and further included in the \$20.8M price tag?

e. If the response to 13 (d), above, is in the negative, describe the parapet wall replacement project, including whether or not a CPCN was requested and received for the project and any cost-benefit or similar studies as to the reasonableness or need for same.

A-36.

a-e. LG&E is not a party to this project.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 37

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-37. Refer to the direct testimony of Lonnie E. Bellar, pages 17-18, wherein he describes the gypsum dewatering project at Mill Creek.

a. Provide a citation to the Case No. in which the Companies requested and received approval for this project.

A-37.

a. The Companies have not requested a CPCN for this project. However, they included the project in their capital investment plan proposed for generation operations in the Companies' 2016 rate cases.[11] While the Commission in that proceeding reviewed the Companies' proposed projects and determined that some projects required a CPCN, it did not find that a CPCN was required for this project.

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[11] Case No. 2016-00370, Direct Testimony of Paul W. Thompson at 22 (Nov. 23, 2016); Case No. 2016-00371, Direct Testimony of Paul W. Thompson at 22 (Nov. 23, 2016).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 38

Responding Witness: Lonnie E. Bellar

Q-38. Refer to the direct testimony of Lonnie E. Bellar, pages 36-37, wherein he discusses the Companies' TSIP and investment in their "aging and deteriorated transmission system infrastructure."

a. Explain, in complete detail, how the Companies prioritize transmission upgrades and enhancements, including the weighting and criteria used.

b. Provide the current ten (10) most prioritized transmission upgrades, replacements or enhancements, whether or not those projects are included in the TSIP. Each project should indicate the size and scope of the project, including the estimated capital and O&M costs, and note whether the project is included in the Companies' TSIP.

A-38.

a. The Companies prioritize transmission upgrades and enhancements (projects) based on factors such as safety, regulatory requirements, asset management, reliability and operational need.

Projects required to meet regulatory standards, including NERC Reliability Standards and Open Access Transmission Tariff requirements, take precedent over other projects.

As described in Lonnie Bellar's testimony, the Companies have an obligation to maintain transmission assets for the long term health and reliability of the system. Prioritization of proactive replacements and reliability projects is discussed in detail in the Annual TSIP Report filed with the Commission.[12]

Additionally, the Companies place a high priority on keeping their Energy Management System up-to-date, ensuring adequate level of critical spare equipment, and improving physical security at higher risk substations.

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[12] LG&E and KU Transmission System Improvement Plan Annual Report, filed in Post Case Referenced Correspondence, Case No. 2016-00371, June 1, 2018, at p.6.

b. The Companies do not prioritize projects in rank order and therefore do not have a list of the ten most prioritized projects. See attachment for a list of current and planned Transmission Expansion Plan projects that are driven by NERC reliability standards and the Companies' Transmission Planning Guidelines or Open Access Transmission Tariff requirements and are therefore higher in priority.

Project #	Description	Project Cost, $000s						
		2018 and Prior	2019	2020	2021	2022	2023	Total
135400	Rebuild the 3.37 miles of 795 MCM AA in the Aiken to Eastwood West section of the Aiken to Eastwood to WHAS 69kV line using 954 MCM ACSR.	-	-	144	1,444	1,300	-	2,888
139984	Replace 7.16 miles of 397.5 MCM 26X7 conductor in the Middletown to Mid Valley Simpsonville 69 kV line including the line risers, using 795 MCM 26X7 ACSR or better conductor.	-	-	-	-	-	387	387
139991	Replace 5.13 miles of 397.5 MCM 26X7 ACSR conductor in the Mid-Valley Simpsonville to Finchville section of the Middletown to Finchville 69 kV circuit with 795 MCM ACSR or better conductor and replace the 1200 A 69kV breaker and CTs at Finchville with 2000 A breaker.	-	78	3,030	-	-	-	3,108
140440	Reconductor the 1.78 miles of 795 MCM 61XAAin the Brooks EK Tap to South Park 69 kV line section to 795 MCM ACSR and MOT the 0.21 miles of 840.2 MCM 24X13 ACAR to 212F.	172	2,837	-	-	-	-	3,009
144065	Replace 2.86 miles of 266.8 MCM 26X7 ACSR conductor in the Adams - Delaplain Tap section of the Adams - Oxford 69 kV line. Use 397.5 MCM 26X7 ACSR or better.	156	3,606	-	-	-	-	3,762
144070	Increase the MOT of the 266.8 kCM ACSR in the Elizabethtown - Elizabethtown #2 Tap section (2.24 mi. 176F), in the Elizabethtown - Rogersville 69 kV line, to 212F.	-	-	19	728	-	-	747
144083	Increase the MOT of the 954 ACSR in the KU Park to Pineville 69 kV line to 212F. (0.16 mi)	-	30	120	-	-	-	150
144108	Install a 69 kV, 9 MVAR capacitor bank at Paint Lick.	131	753	-	-	-	-	883
144330	Add breaker to West County MSD	1,164	-	-	-	-	-	1,164
144488	Replace 138/69 kV, with a 90 MVA transformer at Rodburn; put existing Rodburn 60 MVA at Farmers; replace two breakers at Roduburn due to breaker duty overloads.	709	-	-	-	-	-	709
145803	Reconductor the 2/0 7X CU 3.84 mi with 556.5 MCM 26X7 ACSR or better in the Clay Village Tap to Shelbyville East section of the Shelbyville to West Frankfort 69 kV line.	-	100	3,649	-	-	-	3,749
147219	Replace 138kV terminal equipment rated less than or equal to 1200 Amps (287 MVA) winter emergency rating associated with the Hardinsburg to Black Branch 138kV line with equipment capable of a minimum of 1363 Amps (326 MVA) winter emergency rating.	561	-	-	-	-	-	561
147227	Install a 69 kV, 26.4 MVAR capacitor bank at the KU Hodgenville #744 station.	-	-	-	1,511	-	-	1,511
147228	Replace existing 69 kV terminal equipment rated 1556 amps (186 MVA) or less WE associated with the Elizabethtown 138/69 kV transformer (low-side bushing CT of the transformer and any other equipment rated less than 1556 amps), with equipment capable of 2083 amps WE. Replace existing 138 kV terminal equipment rated 806 amps (193 MVA) or less WE associated with the Elizabethtown 138/69 kV transformer (high-side switch and any other equipment), with equipment capable of 1042 amps WE.	-	150	675	-	-	-	825
147244	Increase the MOT of the 336.4 MCM 19X AA conductor in the Ethel to Nachand 69 kV line (circuit 6670) to 212 deg. F.	2,037	-	-	-	-	-	2,037
147250	Increase the MOT of the 556 ACSR conductor in the Dix Dam to Buena Vista section of the Dix Dam to Lancaster 69 kV line to 212 deg. F.	-	250	-	-	-	-	250
151466	Add redundant bus differential and lockout relays at the Middletown 345 kV bus. A fault on 345 kV bus followed by relay or protection failure causes low voltage violations and overloads.	428	18	-	-	-	-	446
151739	Replace 69kV terminal equipment rated less than or equal to 600 Amps (72 MVA) winter emergency rating associated with the Bonds Mill to Lawrenceburg Tap 69kV line with equipment capable of a minimum of 806 Amps (96 MVA) winter emergency rating.	-	-	-	-	110	-	110
153518	Replace 138/69 kV, with a 90 MVA transformer at Rodburn; put existing Rodburn 60 MVA at Farmers; replace two breakers at Roduburn due to breaker duty overloads.	571	-	-	-	-	-	571
153954	Increase the MOT of the 397.5 ACSR in the Princeton to Walker 69 kV line from 130F to 140F (15.12 mi)	389	-	-	-	-	-	389
156518	Install a 0.66% 345 kV reactor at Trimble County in the Trimble County - Clifty 345 kV line.	546	2,355	-	-	-	-	2,901
156806	Add redundant bus differential and lockout relays at Cane Run 138 kV buses. A fault on 138 kV bus followed by relay or protection failure causes low voltage violations and generators to slip a pole.	742	-	-	-	-	-	742
156819	Add redundant bus differential and lockout relays at West Lexington 138 kV buses. A fault on 138 kV bus followed by relay or protection failure causes low voltage violations and generator instability.	193	-	-	-	-	-	193
156820	Add redundant bus differential and lockout relays at Trimble Co. 345 kV bus. A fault on 345 kV bus followed by relay or protection failure causes low voltage violations and overloads.	504	25	-	-	-	-	529

Project #	Description	Project Cost, $000s 2018 and Prior	2019	2020	2021	2022	2023	Total
157188	Replace 1.4 miles of 1272 MCM 61X AA conductor in the Ashbottom - Southpark 69 kV line, using 1272 MCM 45X7 ACSR or better conductor.	-	-	144	1,247	1,008	-	2,399
157193	Replace the 2.80 miles of 392.5 MCM 24X13 ACAR conductor in the Upper Mill Creek - Riverport 69 kV line section, using 397.5 MCM 26X7 ACSR or better conductor.	-	-	145	1,257	1,015	-	2,417
157200	Increase the MOT of the 556.5 MCM 26X7 ACSR conductor (5.25 mi), from 145 °F to 160 °F in the Bimble to Emanuel section of the Bimble to London 69 kV line.	-	-	50	975	-	-	1,025
157201	Increase the MOT of the 556.5 MCM 26X7 ACSR conductor (0.02 mi.) in the Bimble - Hinkle 69 kV line section, to a minimum of 160°F.	-	-	50	-	-	-	50
157202	Increase the thermal operating temperature of the 795 MCM 26x7 ACSR (23.61 mi) in the Ghent to Blackwell 138 kV line to at least 160°F.	-	50	970	-	-	-	1,020
157203	Increase the MOT of the 556.5 MCM 26X7 ACSR (5.83 mi.) in the Campground - London 69 kV line section, to a minimum of 140 degree F.	-	50	970	-	-	-	1,020
157204	Increase the MOT of the 397.5 ACSR conductor in the Crittenden to Marion S 69 kV from 140°F to 150°F (1.56 mi).	-	25	485	-	-	-	510
157205	Increase the MOT of the 12.46 mi of 397.5 ACSR in the Kentucky Dam (TVA) to Eddyville Prison tap 69 kV line to 212°F.	-	100	1,939	-	-	-	2,039
157206	Increase the maximum operating temperature of the 397.5 MCM ACSR conductor on the Finchville to Southville 69kV section of the Finchville to Bonds Mill 69kV line to at least 160°F	-	25	485	-	-	-	510
157208	Increase the MOT of the 397.5 MCM 26X7 ACSR conductor in the Walker - Hardesty B 69 kV circuit (connected to Walker breaker 123-644), to a minimum of 140 °F.	-	5	-	-	-	-	5
157209	Rebuild the existing double 69 kV circuits from KY Dam to South Paducah, on the existing structures. Resulting configuration will be a single 69 kV circuit, using 397.5 MCM 26X7 ACSR or better conductor.	-	25	302	486	-	-	812
157210	Increase the MOT of the 397.5 MCM 26X7 ACSR conductor (3.81 mi., 165°F) in the La Grange East - Penal Tap section of the Eminence - Centerfield 69 kV line, to a minimum of 176°F.	-	75	1,455	-	-	-	1,530
157211	Construct a new 4.07 mile 69 kV line from Lebanon to Lebanon South using 556.5 MCM 26x7 ACSR. Project 992 adds a ring bus at Lebanon South which should be built in conjunction with this project.	-	150	510	3,938	3,068	-	7,666
157215	Increase the maximum operating temperature of the 397.5 MCM ACSR conductor on the Southville to Bonds Mill 69kV section of the Finchville to Bonds Mill 69kV line to at least 150°F.	-	50	970	-	-	-	1,020
157245	Increase the MOT of the 636 MCM 24X7 ACSR conductor (0.66 mi. at unverified 176°F) to minimum 190°F, and the 795 61X AA conductor (1.67 mi. at unverified 165°F) to a minimum 176°F, in the Oxmoor to Breckenridge 69 kV line (6653).	-	-	70	1,333	-	-	1,403
157690	Increase the MOT of the 397.5 MCM 26X7 ACSR conductor (6.28 mi.) in the Marion - Mexico section of the Princeton - Crittenden County 69 kV line, to a minimum of 140F.	-	-	50	1,200	-	-	1,250
157691	Install a second West Lexington 450 MVA, 345/138 kV transformer and necessary 345 kV breakers to create a 345 kV ring bus configured such that the two transformers do not share a single breaker. Reconfigure the Brown N to West Lexington and Ghent to W Lexington 345 kV lines as necessary	-	-	10	240	-	-	250
157692	Replace 7.34 miles of 795 MCM 26X7 ACSR conductor in the West Lexington - Haefling 138 kV line, using high-temperature conductor capable of at least 1500 A.	-	-	150	5,350	-	-	5,499
157693	Replace 5.19 miles of 795 MCM 26X7 ACSR conductor in the West Lexington - Viley Road section of the West Lexington - Viley Road - Haefling 138 kV line, using high-temperature conductor capable of at least 1500 A.	-	-	150	3,850	-	-	3,999
157736	Replace the 69 kV terminal equipment rated equal to or less than 688 amps SE at Georgetown with equipment capable of a minimum of 992 amps SE, and increase the MOT of the 556.5 ACSR line conductor in the Adams to Georgetown section of the Adams to Haefling 69 kV line to 212°F.	13	323	-	-	-	-	336
157806	Replace the existing 138/69kV transformer at Hardin Co with a 138/69 kV, 185 MVA transformer. Replace the 69 kV Breaker and terminal equipment rated less than 2000 amps WE associated with breaker 178-608 at Hardin County with equipment at minimum capable of 2686 amps WE.	-	-	35	965	-	-	1,000
LI-000081	Reconductor 1.37 miles of 397.5 MCM 26x7 ACSR conductor in the Bardstown - Bardstown Industrial Tap section of the Bardstown - EKPC East Bardstown 69 kV line using 556.5 MCM 26X7 ACSR.	-	-	-	-	-	100	100

Project #	Description	Project Cost, $000s 2018 and Prior	2019	2020	2021	2022	2023	Total
LI-000083	Replace 1.94 miles of 266.8 MCM 18X1 ACSR and 0.27 miles of 266.8 MCM 26X7 ACSR conductors in the Loudon Avenue to Hume Road Tap section of the Loudon Avenue - Winchester 69 kV line, with 397 MCM 26X7 ACSR or better conductor.	63	1,366	-	-	-	-	1,429
LI-000084	Increase the MOT of the 556.5 ACSR Conductor to 160F and 266.8 Conductor to 212F in the Somerset EKPC to Somerset So section of the Somerset EKPC to Russell Co EKPC 69 kV line	-	-	-	-	-	50	50
LI-000085	Increase the MOT of the 266 kCM 26X7 ACSR in the Greensburg-Campbellsville EKPC section of the Green County EKPC-Taylor County 69 kV line from 176F to 212F (8.9 miles).	88	1,045	-	-	-	-	1,133
LI-000086	Replace 1.86 miles of 336.4 MCM 26X7 ACSR conductor in the Eastwood - Simpsonville 69 kV line of the Eastwood - Shelbyville 69 kV line, using 556.5 MCM 26X7 ACSR conductor.	50	1,345	-	-	-	-	1,395
LI-000087	Increase the confirmed MOT of the bundled 795 MCM 45x7 ACSR in the Ashbottom to Cane Run Switch 138 kV line from 150 F to 155F (8.04 mi).	-	-	-	-	65	2,583	2,648
LI-000088	Replace the 795 AA conductor in the Ford to Freys Hill J section of the Worthington to Freys Hill to Ford Tap to Ford 69 kV line with 795 ACSR 26X7, rated at 212F	-	50	2,083	-	-	-	2,133
LI-000090	Incerase the MOT of the 3/0 6X1 ACSR conductor in the Skylight to Harmony Landing 69 kV lineto 212 deg. F.	-	10	-	-	-	-	10
LI-000091	Increase the MOT of the 556.5 MXM 26X7 ACSR conductor in the Green River - Shavers Chapel 69 kV 69 kV line to a minimum rating of 140°F (8.51 miles).	19	236	-	-	-	-	255
LI-000092	Increase the MOT of the397.5 ACSR conductor in the Morganfield 4 to Wheatcroft tap section of the Morganfield to Nebo 69 kV line from 125F to 135F (14.90 mi)	25	2,138	-	-	-	-	2,163
LI-000093	Increase the MOT of the 3/0 6X1 ACSR conductor (10.12 mi. @ 120 F), in the Science Hill to Floyd Tap to Waynesburg 69 kV line to a minimum thermal rating of 130 F.	25	210	-	-	-	-	235
LI-000094	Re-conductor 0.84 miles of 266.8 MCM 26x7 ACSR in the Green Co to Greensburg section of the Green Co to Taylor Co 69 kV line using 397.5 MCM 26x7 ACSR. Coordinate terminal equipment upgrade at EKPC's Green County substation.	-	50	699	-	-	-	749
LI-000095	Increase the MOT of the 556.5 MCM 26x7 ACSR conductor in the KU Park-Stinking Creek 69 kV line to at least 170 deg. F (3.52 miles)	-	50	550	-	-	-	600
LI-000096	Increase the MOT of the 397.5 MCM 26x7 ACSR conductor in the Wofford-Rockhold 69 kV line to 145 deg. F (4.36 miles)	-	50	699	-	-	-	749
LI-000098	Increase the MOT of the 556.5 MCM 26X7 ACSR conductor (3.69 mi.), in the Hinkle - Stinking Creek 69 kV line section, to a minimum of 170 degree F.	-	25	485	-	-	-	510
LI-000099	Replace 0.38 miles of 266.8 kCM 26X7 ACSR conductor in the Campbellsville 2 Tap to Taylor County section of the Lebanon to Taylor County 69 kV line, using 556 kCM 26X7 ACSR or better conductor.	-	755	-	-	-	-	755
LI-000100	Increase the MOT of the 795 MCM 26X7 ACSR to 176 F in the Nelson County to Elizabethtown 138 kV line.	-	-	53	472	-	-	525
LI-000102	Construct Elizabethtown - Hardin Co 69 kV #2 using 1272 MCM ACSR 26X7 conductor.	-	-	38	1,461	-	-	1,499
LI-000106	Increase the MOT of the 397.5 ACSR in the Fairfield-Taylorsville EK Tap section of the Finchville-Bardstown 69 kV line from 135F to 140F (5.89 mi)	25	310	-	-	-	-	335
SU-000099	Install a 11.7 MVAR, 69 kV capacitor bank at Somerset South.	-	1,034	-	-	-	-	1,034
SU-000181	Replace the 69kV terminal equipment rated less than 810 amps WE associated with breaker 108-634 at Adams on the Adams to Delaplain tap 69 kV line with equipment at minimum capable of 900 amps winter emergency rating.	217	4	-	-	-	-	221
SU-000188	Replace the 1200A breaker (213-604) at Boonesboro N and associated breaker CTs with equipment capable of 2000A	191	-	-	-	-	-	191
SU-000191	Replace the 600 amp switches associated with the Carrollton-Lockport 138kV line with 1200 amp switches.	-	-	35	-	-	-	35
SU-000195	Change the 800A CT settings on breakers 96-608 and 96-618 associated with the 161/69 kV transformers at Elihu to 1200A.	-	5	-	-	-	-	5
SU-000196	Replace 600A hookstick disconnects (034-654L & 034-654B) and gang-operated switch 811-605 associated with breaker 34-654, with 1200A equipment at Etown associated with Etown to Etown 4 69 kV line.	-	50	-	-	-	-	50
SU-000198	Replace the 600A 69 kV meter CT at Farley associated with the Farley - Liberty Church 69 kV line with 1200A equipment.	130	-	-	-	-	-	130
SU-000199	Change the setting of the 69kV CT associated with the Haefling-Spindletop 69kV line to 1200 amps	-	5	-	-	-	-	5
SU-000203	Construct Elizabethtown - Hardin Co 69 kV #2 using 1272 MCM ACSR 26X7 conductor	-	1,000	2,999	7,385	1,999	-	13,383

Project #	Description	Project Cost, $000s 2018 and Prior	2019	2020	2021	2022	2023	Total
SU-000205	Install a new capacitor bank at or near Meredith 138kV with a maximum size of 30 MVAR. This may require special equipment to implement and special control systems.	464	303	-	-	-	-	767
SU-000206	Install a 69 kV, 18.0 MVAR capacitor bank at Middlesboro #780.	335	250	-	-	-	-	585
SU-000217	Replace the 69 kV transformer CT on the Tyrone 138/69 kV transformer with at least a 1200 amp CT	-	5	-	-	-	-	5
SU-000236	Replace the 600 amp switches associated with the Georgetown-Lemons Mill 69kV line	263	-	-	-	-	-	263
SU-000246	Replace the existing 138/69kV, 93 MVA transformer at Bardstown. Planning determined a minimum transformer with top nameplate rating of 120 MVA using 8% impedance based on that rating. Also, replace the 69kV terminal equipment rated 1200 amps or less SE with equipment capable of a minimum 1250 amps SE.	510	-	-	-	-	-	510
SU-000248	Construct Elizabethtown - Hardin Co 69 kV #2 using 1272 MCM ACSR 26X7 conductor.	-	25	-	-	-	-	25
SU-000343	Replace 5.13 miles of 397.5 MCM 26X7 ACSR conductor in the Mid-Valley Simpsonville to Finchville section of the Middletown to Finchville 69 kV circuit with 556.6 MCM ACSR or better conductor.	-	30	284	-	-	-	314
SU-000344	Install a 69 kV, 4.5% reactor at Virginia City on the Virginia City to Bond 69 kV line	-	100	378	-	-	-	478
SU-000345	Install a second West Lexington 450 MVA, 345/138 kV transformer and necessary 345 kV breakers to create a 345 kV ring bus configured such that the two transformers do not share a single breaker. Reconfigure the Brown N to West Lexington and Ghent to W Lexington 345 kV lines as necessary	-	-	250	2,749	7,249	2,999	13,246
SU-000347	Replace the existing 345/161 kV, 240 MVA transformer at Blue Lick with a 450 MVA transformer, reset/replace any CTs less than 2000 amps and increase the loadability of relays.	-	-	200	3,513	-	-	3,714
SU-000348	Install a 69 kV, 14.4 MVAr capacitor bank at Bonnieville.	-	-	103	552	-	-	656
SU-000349	Install a 69 kV, 33.6 MVAr capacitor bank at Lemons Mill	-	219	1,016	-	-	-	1,234
SU-000350	Install a 69kV, 38.4 MVAR capacitor bank at Okonite.	-	-	216	948	-	-	1,164
SU-000351	Install a 16.8 Mvar capacitor bank at Taylorsville KU 69kV	-	247	955	-	-	-	1,202
SU-000352	Install a 69 kV, 16.2 MVAR capacitor bank at Warsaw East.	-	-	232	916	-	-	1,148
SU-000353	Install a 69 kV, 23.4 MVAR capacitor at Spencer Road	-	462	479	-	-	-	941
SU-000354	Install a 69 kV line exit at Lebanon including a 69 kV breaker and a 69 kV line exit at Lebanon South. Add a 69 kV, four breaker ring bus at Lebanon South to terminate project 1003 (building a 69 kV line from Lebanon to Lebanon South).	-	-	50	350	1,300	-	1,700
SU-000393	Replace 69kV equipment rated less 690 amps summer emergency at Boyle Co associated with the Boyle Co to Lancaster 69kV line (breaker 101-604) with equipment capable of a minimum of 993 amps summer emergency.	-	8	-	-	-	-	8
SU-000394	Replace 161 kV terminal equipment rated less than or equal to 1662 Amps (463 MVA) summer emergency rating associated with the Matanzas to BREC Wilson 161 kV line with equipment capable of a minimum of 1896 Amps (529 MVA) summer emergency rating.	-	35	-	-	-	-	35
SU-000407	Install a 69 kV line exit at Lebanon including a 69 kV breaker and a 69 kV line exit at Lebanon South. Add a 69 kV, four breaker ring bus at Lebanon South to terminate project 1003 (building a 69 kV line from Lebanon to Lebanon South).	-	-	50	945	2,488	-	3,483

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 39

Responding Witness: Lonnie E. Bellar

Q-39. Refer to the direct testimony of Lonnie E. Bellar, page 40, wherein he describes the Clifty Creek 345kV overload risk.

a. Explain whether the Companies anticipate reflecting this investment in capitalization for ratemaking purposes.

b. Explain whether there will be offsetting revenues from this $2.9M project, and if so, from whom those revenues will be recovered.

c. Explain the need for and use of the 345kV Trimble County to Clifty Creek line.

A-39.

a. Yes.

b. See the response to AG 1-7.

c. See the response to AG 1-7.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 40

Responding Witness: Daniel K. Arbough

Q-40. Refer to the direct testimony of Lonnie E. Bellar, page 45.

a. Provide the same table with capital expense additions in transmission, by company, calculated based on the 13-month average capitalization as used in the test period of the last rate cases, compared to 13-month average capitalization as used in the test period of these cases.

A-40.

a. Changes in capitalization cannot be tracked to individual items as capitalization is impacted by normal operating activities, capital expenditures, and financing activities.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

Case No. 2018-00295

Question No. 41

Responding Witness: John K. Wolfe

Q-41. Refer to the direct testimony of Lonnie E. Bellar, page 50, wherein he discusses the investments and capital costs related to the Companies' DA projects.

a. Provide, broken out by company, the original capital estimate for the DA project, the actual capital expended to-date, the estimated investment through completion of the project, the estimated in-service date and the actual in-service date.

b. Provide the estimated completion date for the project DA, by company if the date for each is different.

A-41.

a. The original capital estimate for the DA project, the actual capital expended to-date and the estimated investment through completion of the project are presented in the table below:

(in Thousands)	Original Capital Estimate	Actual Capital Expended to-date	Estimated Investment through Completion of the Project
LG&E	66,312	17,336	48,976
KU	46,045	17,880	28,165
Total	112,357	35,216	77,141

The estimated in-service date is December 2020 for both Companies.

b. The estimated completion date for the DA project is December 2020 for both Companies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 42

Responding Witness: John K. Wolfe / Robert M. Conroy / Lonnie E. Bellar

Q-42. Refer to the direct testimony of Lonnie E. Bellar, page 50, wherein he states, "A proposed expansion of DA is discussed in the Distribution Plan attached to my testimony."

a. Are the Companies requesting in this matter amendments to the CPCNs they received for the current DA program? If the response is in the affirmative, provide a citation to the record where they have made their request. If the response is in the negative, explain why the Companies believe they can expand the DA program without Commission approval.

b. Explain why an expansion of a yet-completed plan is in the best interest of the Companies' customers. Any response should include the cost-benefit analyses conducted by the Companies to evidence as much.

A-42.

a. No, the Companies are not requesting any modifications to their existing CPCNs for the Distribution Automation program. The Companies acknowledge that the Commission's Order of April 13, 2016 in Case No. 2012-00428 requires each to apply for a CPCN for major distribution grid investments for DA. The Companies are currently studying a potential expansion of their DA programs but have yet to perform the required studies to make a final determination as to proceed. If the Companies determine that an expansion is cost-beneficial, such expansions would not begin earlier than 2022. As KRS 278.020(1)(e) requires that any construction begin on the facilities for which a CPCN is granted within one year of the issuance of the CPCN, any application for a CPCN at this juncture would be premature.

b. As part of its DA program, through July 2018, EDO installed nearly 360 electronic reclosers which resulted in 6,281,428 avoided outage minutes including more than 16,763 avoided interruptions. These results show DA to be an effective reliability improvement program. Thus, DA is planned to be expanded to provide similar benefits to all distribution circuits having a total of at least 500 customers and a serviceable circuit tie for switching (40% of all circuits, 70% of customers). A cost-benefit analysis will be completed as part of the final project approval process.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 43

Responding Witness: John K. Wolfe

Q-43. Refer to the direct testimony of Lonnie E. Bellar, pages 51-52, wherein he discusses the Distribution Substation Transformer Contingency program.

a. Provide the cost-benefit justification for the Companies investing $37M in redundant, spare equipment.

b. Provide the specific criteria used to determine that the redundant, spare equipment should be recorded as capital asset.

A-43.

a. The $37M investment is the least cost investment when compared to the cost of unserved energy (outages) to the customer. The benefits of the investment in the Distribution Substation Contingency program are consistent with the Interruption Cost Estimator (ICE) calculator sponsored by the Department of Energy which assigns a cost to the customer of an outage by kWh. The cost of unserved energy (CUE) is calculated by the amount of load which would go unserved under the loss of a substation transformer multiplied by the estimated time to install permanent or temporary capacity and the determined ICE value. The Companies' existing Investment Proposals that have been approved for the Distribution Substation Transformer Contingency program through November 27, 2018, are attached.

b. Equipment purchased for a capital project, whether in-service or Capital Spare, is treated as capital asset per the Companies' accounting policy.

Investment Proposal for Investment Committee Meeting on: ____N/A__________

Project Name: Central City Substation and Distribution 4kV to 12kV Conversion

Total Expenditures: $_857k (Including $78k of contingency)

Project Number (s): _Distribution Substations 144767 Distributions Lines 147823

Business Unit/Line of Business: _Electric Distribution Operations____

Prepared/Presented By: _Tim Smith/Mike Leake/Beth McFarland_

Executive Summary

KU Electric Distribution requests approval for funding to convert the Central City 4kV system to a 12kV Distribution system to eliminate low voltage issues and to enhance reliability and contingency in the Central City area. Central City is located in Muhlenberg County and serves 2,947 customers. The area is targeted for improvement as a result of its reliability performance, more specifically, it's low voltage issues over the last several years.

Central City 4kV and Central City South 4kV substations consist of long heavily loaded feeders that routinely experience low voltage as verified by both System Planning models as well as actual customer complaints. Shifting load between the two substations as well as load shifts to Muhlenberg Prison Substation have been studied and do not resolve the voltage issues.

The project includes converting the two existing dual voltage substation transformers to 12kV (Central City 4kV 571-1 and Central City South 4kV 405-1) and the conversion of six Central City and Central City South distribution circuits from 4kV to 12kV.

This project was included in the 2015 Business Plan (BP) in 2015-2017. In May 2015, the Corporate RAC approved shifting the funding from 2016 to 2015 to complete the project in 2015.

Background

The Central City distribution system consists of two 4kV substations. Both substation transformers are dual voltage on the low voltage side and capable of being converted to 12kV. Central City 571-1 and Central City South 405-1 substations are located within the city limits of Central City in Muhlenberg County, Kentucky. The two substations combine to serve the entire city (approximately 2,947 customers) with Central City 571-1 on the northern end of the city and Central City South 405-1 to the south. Central City 571-1 has a 67kV-13.09X4.36kV 7.5/10.5MVA LTC transformer with an average summer peak of 6,665kVA and an average winter peak of 6,733kVA. Central City South 405-1 also has a 67kV-13.09X4.36kV

7.5/10MVA LTC transformer with an average summer peak of 6,486kVA and an average winter peak of 6,443kVA. Records indicate there are 43 critical customers on the Central City distribution system.

Low voltage complaints from customers as confirmed by operations center monitoring and the distribution system planning modeling tool is a primary reason for the request for funding to convert the Central City distribution system to 12kV. Contingency support in the event of a transformer failure at either station is also a consideration. Currently substantial load will go unserved in the event of a substation transformer failure or outage at either station under heavy loading conditions. Conversion to 12kV will improve reliability and contingency in the area by allowing load to be transferred more effectively between stations while allowing load to also be transferred to other area 12kV stations.

- **Alternatives Considered**
  1. Recommended option: NPVRR ($000s): $1,114
     The recommended option is to convert the entire 4kV Central City distribution system to 12kV. Both Central City and Central City South have an existing 7.5/10.5 MVA, 67-13.09X4.36kV substation transformer. The distribution portion of the project will include replacing all of the 4kV rated equipment with 12kV rated equipment. The total estimated cost is $857k.

  2. Do nothing option: NPVRR ($000s): $2,143
     Both Central City 571-1 and Central City South 405-1 Substations will remain at 4kV as isolated 4kV systems with ties only to each other and no circuit ties to surrounding 12kV sources. Voltage and contingency issues and concerns will not be addressed and low voltage during heavy loading will result in continuous customer complaints. Support between substations is limited by circuit capacity at 4kV (4kV requires 3 times the current of 12kV systems for the same load); during the loss of either transformer at peak, significant load will go unserved until the transformer is restored (estimated 24-36 hours). While the loss of an entire substation is a relative low probability event, planning studies indicate an outage of Central City substation could cause as much as 3,275kW to go unserved until the station is restored under peak loading conditions. During an outage of Central City South substation, an estimated 4,900kW would go unserved. Conversion to 12kV will allow full utilization of the transformer capacity at each station for contingency support along with support from two nearby 12kV substations (Muhlenberg Prison Substations and Shavers Chapel) allowing all load to be restored through switching in approximately two hours. 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 minimum cost of unserved energy would be $1,239k for Central City and $1,854k at Central City South. The estimated "cost of unserved energy" based on an annual 5% probability of an outage is approximately $155k annually.

3. Alternative 1: NPVRR ($000s): $ 1,675

This option resolves voltage issues through the installation of line voltage regulators and provides comparable contingency improvements to the recommended option through distribution line improvements on the Central City 4kV System. During an outage at peak, 2.1 to 2.7 MW could go still go unserved during an outage of either Central City Substation. This alternative would require the installation of a total of six regulator banks, one 4kV to 12kV conversion bank and reconductoring a portion of existing distribution circuits to larger wire (about 13,929'). Actual application of multiple regulator and transformer banks could be problematic because of the difficulty of load balancing with very high circuit currents (approaching 900 amps) at 4kV. This option is not recommended because it is technically inferior to the recommended option at a higher cost. The estimated cost is $1,289k.

Project Description

- **Project Scope and Timeline**

    - Substations: Convert two dual voltage substation transformers to 12kV (Central City 4kV 571-1 and Central City South 4kV 405-1). This estimate includes funds for labor, materials and wildlife protection to convert the substation transformers and substation structures for 12kV operation. The estimated cost is $453k.
    - Distribution: Convert six Central City distribution circuits from 4kV to 12kV. The estimate includes funds to replace all 4kV rated materials and equipment for 12kV operation. The estimated cost is $404k.

- July 2015: Open projects.
- July 2015: Complete engineering design, preliminary construction and order materials.
- July-Sept 2015: Complete conversion and construction:
    - Build a temporary 4kV substation at Central City South 405-1 to serve circuits 1649, 1650 and 1651.
    - Build a temporary overhead 4kV circuit around Central City South Substation so that the existing substation can be de-energized to allow bus work upgrades to be completed.
    - Build a temporary transmission tap to serve the temporary substation.
    - Upgrade the de-energized Central City South Substation 405-1 from 4kV to 12kV.
    - Convert circuits 1649, 1650 and 1651 from 4kV to 12 kV in a planned order and return to Central City South 12kV.
    - Convert Central City 4kV 571-1 circuits 1645, 1646 and 1648 from 4kV to 12kV and serve from Central City South 12kV and Muhlenberg Prison 12kV.
    - Convert the Central City 571-1 substation from 4kV to 12kV.
    - Return circuits 1645, 1646 and 1648 to Central City 551-1 12kV.
- October 2015: Remove temporary substation at Central City South and site cleanup.

- **Project Cost**

  The total estimated cost of the Central City Substation and Distribution 4kV to 12kV Conversion project is $857k. The substation and distribution cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% of contingency ($78k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - Substation 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)	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	687				687
2. Cost of Removal Proposed	170				170
3. Total Capital and Removal Proposed (1+2)	857	-	-	-	857
4. Capital Investment 2015 BP	363	140	258		761
5. Cost of Removal 2015 BP	12	29			41
6. Total Capital and Removal 2015 BP (4+5)	375	169	258	-	802
7. Capital Investment variance to BP (4-1)	(324)	140	258	-	74
8. Cost of Removal variance to BP (5-2)	(158)	29	-	-	(129)
9. Total Capital and Removal variance to BP (6-3)	(482)	169	258	-	(55)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed					-
2. Project O&M 2015 BP					-

These projects were budgeted in the 2015 BP. The Substation portion of the Central City 4kV to 12kV Conversion project was budgeted in 2015 at $375k (project 144767). The Distribution piece was budgeted in 2016 for $169k (project 144750) and in 2017 for $258k (project 131686). In the proposed 2016 BP, there was an additional $80k for the substation work and $258k for the distribution circuit work in 2016 and 2017. In May 2015, the Corporate RAC approved shifting this funding from 2016 and 2017 to 2015 to complete this project. In addition, another $146k was needed for the circuit work and that funding was reallocated in June 2015 through the EDO RAC process from another EDO substation project.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 98
Contract Labor:	$ 418
Materials:	$ 50
Local Engineering:	$ 79
Transportation:	$ 12
Burdens:	$ 122
Contingency:	$ 78
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 857

Financial Analysis - Project Summary ($000)	2015	2016	2017	2018	2019	Life of Project
Project Net Income	(16.00)	(21.00)	33.00	44.00	41.00	749.00
Project ROE	-7.10%	-4.90%	8.00%	11.10%	10.80%	9.70%

- **Assumptions**
  - The estimated cost of the Distribution conversion will be comparable to the actual cost observed from recent similar 4kV to 12kV conversion projects.
  - The project unknowns will not exceed the estimated contingency amounts.
  - Project will be completed in year 2015.

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

- **Risks**
  - Failure to complete the 4kV to 12kV conversion will result in continued low voltage conditions during peak seasons and increased risks of customer complaints.

Conclusions and Recommendation

It is recommended that the Central City Substation and Distribution 4kV to 12kV Conversion project be approved for $857k to convert the Central City system to 12kV to address low voltage conditions and improve reliability and contingency for the Central City service area.

Investment Proposal for Investment Committee Meeting on: _August 31, 2016_

Project Name: _Corbin US Steel Substation Transformer Addition Project_

Total Expenditures: $_2,031k (includes $185k contingency)

Project Number: __Substation- 152589, Distribution- 153178, Transmission- 151771_

Business Unit/Line of Business: _Electric Distribution Operations_

Prepared/Presented By: Tim Smith/Beth McFarland

Executive Summary

This Investment Proposal (IP) requests funding for the installation of a new substation transformer at the KU Corbin US Steel Substation located in Corbin, Ky. Corbin US Steel Substation currently has one 10.5MVA transformer and currently serves 356 customers including one major manufacturer, CTA Acoustics (approximately 5MVA). The substation is projected to overload by the summer of 2017 due to two new large industrial customers beginning operations in the Corbin area. The purpose of this IP is to request funding to install a new 14MVA transformer at Corbin US Steel Substation and the associated transmission tap and distribution improvements. This IP provides for substation enhancements necessary to serve the expected new load, provides for future load growth in the area, and removes the Corbin US Steel Substation from the N-1 Distribution Transformer list (transformers that cannot be fully backed up for a failure of the substation transformer during high load periods during the year).

A contract for electric service has been signed for 4.3MVA with Hendricks Resources with the potential for a 2MVA phase II expansion for a total of 6.3MVA in new load by the 2017/2018 timeframe. Hendricks Resources is a coal reclaiming facility immediately adjacent to the existing Corbin US Steel Substation. Euro Sticks, a French owned company and maker of ice cream and coffee stir-sticks has publicly announced plans for a 2.2MVA manufacturing facility to be housed in an existing “spec building” at nearby Southeast Kentucky Business Park. Both customers expect to be operational by mid-year 2017. Without capacity enhancements, the Corbin US Steel Substation transformer’s forecasted summer demand is projected to be 123% to 142% of its summer rating between the summer of 2017 and 2018 contingent upon the customer’s operating schedule and expansion plans.

Funding is requested in the amount of $2,031k to complete a system enhancement project in the 2016/2017 timeframe to install a new 14MVA, 12kV transformer, substation steel structures, 3-12kV 1200 amp circuit breakers, and one 69kV tap and switch pole at Corbin US Steel Substation to meet existing and pending service requirements and remove Corbin US Steel from the N-1 Distribution Transformer list. The timing and size of the load addition at Corbin US Steel was only recently confirmed and, as such, this project was not included in the 2016 BP. This project is included in the 2016 forecast and proposed 2017 BP. The 2016 spending was approved by the Corporate RAC in July.

Background
Corbin US Steel 12KV Substation (795-1) currently is a single transformer substation built on an easement on the abandoned former Corbin US Steel mine property. The existing transformer is a 1975 vintage General Electric 67/13.09X4.36KV LTC unit that was installed in 1978. The substation transformer has had an actual summer peak of 6.7MVA and a winter peak of 7.3MVA. The most recent summer and winter load forecasts are 6.4MVA and 6.6MVA respectively. During the summer, there is only 4.1MVA of unused capacity available to serve new load.

There are two existing distribution circuits extending from this substation. Circuit 0289 is a circuit tie to Corbin East 12KV (844-1). Corbin East has a 14MVA transformer with about 6MVA of capacity available at peak and the tie circuit has limited transfer capability beyond that level without significant reconductoring and the addition of one or more sets of line regulators. Circuit 0288 is a 397 ACSR feeder that extends south of the substation and feeds 100% of the substation load (356 customers) and has no other circuit ties.

On March 14, 2016, the Kentucky Utilities Company received an Electrical Load Data Sheet with details for a 60,000 Sq.-Ft, 4.3MVA coal reclaim facility with a potential to grow to 6.3MVA in the second year of operation. On June 20, 2016, Hendricks Corbin LLC signed a "Contract for Electric Service" for 4.3MVA. Hendricks anticipates a service need date of the first quarter of 2017.

On June 30, 2016 Euro Sticks Group and Kentucky Governor Matt Bevin announced the plans for a new plant at the Southeast Kentucky Regional Business Park in Knox County, Kentucky. Euro Sticks has submitted an Electrical Load data Sheet with an estimated peak demand of 2.2MVA. Euro Sticks expects to be operational in the first quarter of 2017.

The total customer submitted new load additions equate to 6.5MVA initially and potentially 8.5MVA should Hendricks implement the expected phase II expansion plan. With the addition of the initial new loads, the transformer will be loaded to 123% of its summer rating which is above the transformer's short duration emergency rating of 120%. An 8.5MVA load addition would drive the substation to 142% of its summer rating.

Corbin US Steel has limited ties to other stations and is currently on the N1DT list (transformers that cannot be fully backed up for a failure of the substation transformer during high load periods during the year). The recommended solution provides capacity to serve the new load, removes Corbin US Steel from the N1DT list, provides additional capacity and contingency for the area and provides flexibility to perform scheduled maintenance at the station without the need to temporarily install a portable transformer reducing future operating costs.

Alternatives Considered

1. Recommended Option: Add a new 10/14MVA Transformer NPVRR $2,541
   The recommended option is to perform substation site preparation, install a new 10/14MVA 67/13.09kV LTC substation transformer, one 69KV HV structure, 3-1200 amp breakers, 2-LV bay structures with associated switches and bus work, new

transmission tap and minor distribution improvements. The cost of the recommended option is $2,031k.

2. Do nothing Option: NPVRR $3,750
KU has an obligation to serve the new load. The Do Nothing option would only provide for retroactive monitoring of load additions. The station is not on SCADA and cannot be monitored in real time. Loads can only be assessed retroactively after substation meter data is read monthly. Significant and routine overloading of a transformer up to and above the 120% summer emergency will reduce the life of the transformer and accelerate failure of a high value asset and result in an outage that can last 24 hours or more while the transformer is replaced or a mobile transformer is installed. While the loss of an entire substation is normally a relatively low probability event, operating at or above the emergency limit will significantly increase the probability of short-term failure.

   Corbin US Steel has limited ability to transfer load to other stations during an outage event. At peak load, approximately 6.980MVA would go unserved in the event of a transformer failure at Corbin US Steel once the first 6.5MVA of new load is in operation. A conservative assumption would be that the 42 year old transformer will fail within four years (25% probability/year) when routinely overloaded and operating at or above its emergency limits frequently, even with just the first phase of load additions. The estimated cost of a replacement transformer is $546k. For modeling purposes in the CEM, it was assumed that the failure and replacement would occur in year 4. The assumption is a new replacement unit properly sized to serve the existing and new load.

   With significant overload and an expected failure within four years, the cost of Do Nothing would include the accelerated cost to replace a failed transformer ($546k) with a properly sized unit combined with a cost of unserved energy during the resulting long duration outage. Using the corporate "cost of unserved energy" ($17.2/kWh) with estimated 6.980MVA going unserved at peak for an incremental 24 hours, the cost of unserved energy in year 4 would be:
   $17.2/kWh x 6980 kVA x 24 hours) = $2.881M, escalated by CPI to year 4 is $3.110M.

   With the replacement of the failed transformer, the substation would remain without contingency for future failures and the probability for failure or outage on a new transformer would be similar to Alternative 1 (2%/year).

3. Alternative 1: NPVRR $2,715
This option replaces the existing 10.5MVA transformer with a 12/22.4MVA substation transformer. While this option would address the new load in the short term, it provides no contingency in the event of a future transformer outage. The cost of this option is estimated at $1,500k. Under this assumption, the capital cost of improvements would also be combined with the baseline cost of unserved energy with a normal probability of a transformer outage or failure in any given year (2%/year) at peak for the same incremental 24 hours to determine the NPVRR. The cost of unserved energy would be:

   2% outage probability/year ($17.2/kWh x 6980 kVA x 24 hours) = $57,627/year

Project Description

- **Project Scope and Timeline**
  Substation Project # 152589:
  - Perform substation site work on substation easement obtained from landowner. Install one 10/14MVA 69/13.09 kV substation transformer, 1-69KV HV structure, 2-LV bay structures and the associated switches and 3-1200A breakers. The small portable will be utilized for this project. Estimated cost $1,566k.

  Distribution Project # 153178:
  - Install one new exit circuit and primary meter pole to provide primary 12.47 kV service to Hendricks LLC. Estimated cost is $15k.

  Transmission Project # 151771:
  - Install one new 69KV tap, 2-self-supporting 69kV pole structures, one 69kV switch and the removal of one 60' wood transmission pole. Estimated cost is $450k.

  Project Time Line:
  - July 2016: Perform engineering design, field surveys, TSR submittal and preconstruction meetings.
  - September 2016: Open Project.
  - September 2016: Order Transmission structures, substation steel, and substation transformer.
  - September-December 2016: Substation site prep, filling and grading. Install temporary tap for customer's construction power.
  - January-April 2017: Complete foundations, transformer pad & associated substation infrastructure.
  - May-July 2017: Install Transmission poles and 69KV switch installation, install distribution exit circuit & permanent primary meter pole, install substation steel package, small portable set up, place new substation transformer on pad.
  - July 2017: Complete connections, equipment check out, site cleanup.
  - August 1, 2017: Commission new substation.

- **Project Cost**
  The total estimated cost of the project is $2,031k (includes $450K for transmission lines). Cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% contingency ($185k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  The substation transformer and breakers will be ordered using existing contracts following established Supply Chain practices. Bids for other substation and transmission material and labor will be prepared as necessary following established Supply Chain practices.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	**2016**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	600	1,431	-	-	2,031
2. Cost of Removal Proposed	-	-	-	-	-
3. Total Capital and Removal Proposed (1+2)	600	1,431	-	-	2,031
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)	(600)	(1,431)	-	-	(2,031)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(600)	(1,431)	-	-	(2,031)

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)	-	-	-	-	-

This project is not included in the 2016 Business Plan, but was approved in the 6&6 2016 RAC forecast and is incorporated in the 2017 BP at the full amount of the project.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 108
Contract Labor:	$ 471
Materials:	$ 974
Transportation:	$ 6
Local Engineering:	$ 172
Burdens:	$ 115
Contingency:	$ 185
Net Capital Expenditure:	$ 2,031

Financial Analysis - Project Summary ($000)	**2016**	**2017**	**2018**	**2019**	**2020**	**Life of Project**
Project Net Income	-	66.00	101.00	97.00	92.00	1,791.00
Project ROE	0.00%	4.80%	8.10%	10.00%	10.00%	9.60%

- **Assumptions**
  - Two large commercial customers will complete new facilities in 2017 and loads will match load forecasts.
  - Substation easements will be obtained for the substation expansion.

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

- **Risks**
  A deferment of the project will result in significant overloading of the existing 10.5MVA transformer and could result in the failure and replacement of a high cost asset and an increased exposure to an extended outage for both new and existing customers. The near term failure of the existing transformer would result in an extended loss of service for 356 customers in the Knox and Whitley County areas.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Corbin US Steel Substation Transformer Addition Project to add a second transformer to Corbin US Steel to serve 6.5MVA to 8.5MVA of new load for $2,031k.

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 Chief Financial Officer	Victor A. Staffieri Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: December 19, 2016

Project Name: Highland Distribution Substation Transformer Contingency Project

Total Expenditures: $2,447k (includes $408k of contingency)

Project Number(s): Distribution Substations 153586, Distribution Lines 153587

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Kevin Patterson/Beth McFarland

Executive Summary

LG&E Electric Distribution Operations (EDO) requests funding approval for the distribution substation and circuit improvements required to provide full back-up capacity for the LG&E Highland 12kV substation. Highland Substation is located on Stephens Ave. just west of Bardstown Rd. in the heart of Louisville's dense and highly visible Highlands neighborhoods. Presently, if the Highland 12kV Substation transformer were to fail during peak load conditions, up to 3,000 customers would be without service up to five days, until the failed substation transformer capacity could be replaced. Once this proposed project is completed, all customers will be restorable within four hours or less by switching via open tie points to surrounding substations.

Specifically, the Highland Distribution Substation Transformer Contingency Project consists of upgrading five circuits from four adjacent substations (Hancock, Dahlia, Locust and Hillcrest) to enable year round load transfer of all 12kV load in the event of a failure of the Highland 12kV transformer. Substation exit cable capacity will be doubled on each of the five circuits, increasing the capacity of each feeder up to the overhead conductor rating. In addition, one circuit (DA-1241) will have approximately 3,000' of overhead conductor upgrades.

The completion of this proposed project will enable EDO to remove the Highland 12kV substation transformer from the Distribution Substation Transformer Contingency Program (N1DT) list. This list identifies distribution substation transformers, which in the event of a transformer failure during high load periods, cannot be completely restored by switching to surrounding substation and circuits. Planned project completion is prior to 2017 summer loading conditions.

Project costs are estimated to be $2,447k. This project, as it is now planned, was not specifically identified in EDO's proposed 2017 Business Plan (BP); however, it is currently EDO's highest ranked N1DT project on a benefit to cost ratio. EDO's 2017 BP includes $7.2M in 2017 for the N1DT Contingency Program which will be used to fund this project.

Background

The Highland Substation is located on Stevens Avenue just west of Bardstown Road, in the heart of Louisville's Highlands district, and serves approximately 10,054 commercial and residential customers. All of the 12kV load at this substation is served from a single 69/12kV, 44.8 MVA transformer that was installed in 1989. The station is a summer peaking station, and peak load on the distribution transformer reached 37.5 MVA during the 2016 summer, but has exceeded 40 MVA in past years (2010-2013). System Planning studies show that approximately 32 MVA can be transferred through existing circuit ties leaving approximately 8 MVA of load unserved under peak conditions. Limitations on circuit ties to other stations are primarily due to the ratings of the underground substation exit cables which are rated less than the overhead conductor ratings.

Due to the difficulties in setting up a mobile or spare transformer at this location, it could take up to five days to install replacement capacity. During this time, some customers would be without service for extended periods of time until the substation transformer is replaced, a process that would take multiple days due to the complexity of road transport, and oil removal and processing, for a substation transformer of this size.

Due to the large transformer size and limited space available inside the substation, expansion opportunities within the existing facility are not a practical option. Highland Substation is unique in that a mobile transformer, which is a back-up solution for most LG&E substations, is not a viable alternative at Highland due to the lack of space inside the substation and the physical constraints external to the substation. The 69/12kV, 44.8 MVA distribution transformer is located in a partially walled substation that does not afford the safe use of a mobile transformer within the facility. In the event of a substation transformer failure this limitation significantly increases the installation time of replacement capacity from an average 24-36 hours to up to five days. During peak load conditions, it is estimated that up to 8 MVA of residential and commercial load cannot be transferred if the Highland transformer failed. This load would be along Bardstown Road in close proximity to the substation.

EDO's proposed project will increase circuit capacity at surrounding stations by installing additional conduit and exit cable at four substations (Hancock, Locust, Dahlia and Hillcrest), which will enable all load to be transferred to adjacent substations year round. Additionally, approximately 3,000 feet of overhead conductor will be upgraded to 336kCM Aluminum conductor to enhance switching capability.

In addition to the circuit upgrades, this project includes the purchase of additional substation equipment that will reduce the time to install a new transformer in the event of a failure of the existing unit. This equipment will enable an emergency spare to be installed in place of the existing unit, reducing the time Highland load must be served from other stations. The equipment will also shorten the time required to permanently replace a failed unit to approximately three weeks, from the current nine months to rewind and reinstall the failed unit.

Alternatives Considered

1. Recommended Option: NPVRR ($000): $2,863
   The recommended option is to install new conduit and exit cable at four nearby substations to increase the capacity on five circuits to the ratings of the overhead conductor. Also, reconductor approximately 3,000 feet of overhead conductor to 336kCM Aluminum, and purchase substation equipment which enables reduction of replacement time of the existing transformer. The estimated cost of this option is $2,447k.

2. Do Nothing Option: NPVRR ($000): $5,478
   The "Do Nothing" option is not recommended because it continues to leave the Company exposed to exceptional risk in the event of a loss of the Highland 12kV transformer. Approximately 3,000 out of the Highland Substation 10,000+ retail, commercial and residential customers could be subjected to intermittent interruptions during peak load conditions. This situation could last for up to five days, for eight hours per day. This would result in a highly visible condition with significant detrimental impact to the area. Using standard corporate metrics to quantify this N1DT risk, the total estimated "Cost of Unserved Energy", when considering a Highland 12kV outage (8 MW unserved for 8 hours/day for 5 days; $17.2/kWh; 5% probability) is approximately $275k annually.

3. Alternative 1: NPVRR: ($000s) $8,664
   This option considers the installation of a new 69/12kV, 44.8 MVA transformer and associated equipment at Highland Substation plus associated transmission and distribution line improvements. This option would require the purchase of the two adjacent homes (not currently for sale), demolition of the existing structures (which could generate negative attention from neighborhood or preservation groups), and installation of the new equipment. This option would also require the expansion of the wall surrounding the property to maintain the aesthetic of the existing facility. The additional capacity would enable the immediate transfer of load in the event of a failure on either transformer. This alternative is not recommended due to the high cost and the high impact on the area. The estimated cost of this alternative is $7,500k.

Project Description

- **Project Scope**
  - Substation project #153586: estimated cost $644k ($644k-2017).
    - Install larger termination cubicles at Hancock, Locust, Dahlia and Hillcrest Substations.
    - Purchase new bushing box for Highland Substation to reduce transformer replacement time in the event of a failure.
  - Distribution project #153587: estimated cost $1,803k ($1,803k-2017).
    - Install additional required conduit at Hancock, Locust, Dahlia and Hillcrest Substation.
    - Pull additional underground cable on five circuits to increase capacity to overhead conductor rating

    - Reconductor approximately 3,000 feet of overhead conductor on DA-1241 and DA-1242 to increase switching capability.

- **Project Timeline**
  - December, 2016: Open Projects, complete design work and bid projects.
  - January, 2017: Award bids, order equipment, schedule work.
  - February-April, 2017: Complete construction of new conduit, overhead work.
  - April-June, 2017: Install larger substation cubicle compartments and pull cable.
  - June 2017: Complete distribution conductor splicing and relay work for new circuits.
  - July 1, 2017: Complete all remaining check-outs and complete project.

- **Project Cost**
  - The estimated cost of the proposed project is $2,447k. The substation and distribution line cost estimates are consistent with the "Preliminary" engineering design designation, and are based on field experience from similar projects. There is an estimated 20% of contingency ($408k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - Substation and distribution work will be bid using established Supply Chain procedures.
  - For other requirements, Substation Construction and Maintenance (SC&M) and Distribution Operations 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	2,402				2,402
2. Cost of Removal Proposed	45				45
3. Total Capital and Removal Proposed (1+2)	2,447	-	-	-	2,447
4. Capital Investment 2017 BP	700				700
5. Cost of Removal 2017 BP	-				-
6. Total Capital and Removal 2017 BP (4+5)	700	-	-	-	700
7. Capital Investment variance to BP (4-1)	(1,702)	-	-	-	(1,702)
8. Cost of Removal variance to BP (5-2)	(45)	-	-	-	(45)
9. Total Capital and Removal variance to BP (6-3)	(1,747)	-	-	-	(1,747)

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)	-	-	-	-	-

EDO did not specifically budget this proposed project in its 2017 Business Plan. However, EDO did allocate $700k in its plan for property, to allow for future substation expansion near Highlands Substation. EDO plans to fund the remaining capital needs for the project ($1,747k) from its approved N1DT Contingency Program budget (totaling $7.2M in the 2017 BP). There is no transmission component to this project.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 296
Contract Labor:	$ 735
Materials:	$ 543
Local Engineering:	$ 173
Burdens:	$ 292
Contingency:	$ 408
Reimbursements:	($ 0)
Net Capital Expenditure:	$2,447

- **Assumptions**
  - Estimated costs were based on costs experienced with similar past projects. Construction bids have not been completed by contractors.
  - Project unknowns will not exceed estimated contingency amounts.

- **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 customers in the area for a prolonged period in the event of a transformer failure during peak load conditions. Replacement of the transformer could take up to five days and result in recurrent outages in a highly visible area of Louisville.

Conclusions and Recommendation
EDO recommends that the Investment Committee approve the Highland Distribution Substation Transformer Contingency Project for $2,447k, enabling to removal of the Highland 12kV transformer from the N1DT Contingency Program 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 Chief Financial Officer	Victor A. Staffieri Chairman, CEO and President

Investment Proposal for Investment Committee Meeting on: April 29, 2015

Project Name: Innovation Drive Substation N-1 Distribution Transformer Enhancement

Total Expenditures: $1,344k (including $134k of contingency)

Project Number(s): Distribution Substations: 146708, Distribution Lines 146707

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Cline / Beth McFarland

Executive Summary

Electric Distribution requests approval for funding to complete the distribution substation improvements and associated minor distribution line work required to remove the KU Innovation Drive substation from the "N-1 Distribution Transformer List".

The N-1 Distribution Transformer 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 located in the near-by vicinity. Complete restoration to all customers served from the transformer would require either replacement of the failed transformer or installation of a portable transformer.

The Innovation Drive substation is located in north Lexington, KY and serves a large number of customers (approximately 3,876). Circuit configurations and heavy loading on nearby substations and circuits prevent service from being restored to all customers served from Innovation Drive substation in the event substation transformer 428-1 fails under heavy load conditions. Service to these customers will remain out until the failed transformer is replaced or a portable is installed. The recommended option to mitigate this exposure is to replace the existing Innovation Drive 428-2 10/14 MVA, 138-12kV transformer with a 20/37.3 MVA, 138-12kV transformer and to modify the distribution circuits as needed to accommodate load transfers. This option is the least cost option and is expected to provide additional capacity to allow restoration of service to all customers served from the Innovation Drive substation in the event of an outage to either of the Innovation Drive substation transformers without the need to install a portable transformer – a process that typically requires 18-36 hours. In addition to the recommended project, other alternatives were considered which included the installation of additional transformer capacity in existing substations and the construction of a new substation in the area. These considerations were eliminated due to cost.

This project is scheduled to begin in May 2015, with the distribution circuit improvements to be completed in 2015 and the substation improvements to be completed in 2016.

The total estimated cost of the proposed Innovation Drive substation and distribution improvements is $1,344k. The 2015 Business Plan includes a total of $10.4M in 2015-2018 as a part of the approved "N-1 Distribution Transformer" initiative. The estimated $1,344k for the Innovation Drive project will be reallocated from this project through the Corporate RAC process.

Background

The Company's "N-1 Distribution Transformer" 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 in the near-by vicinity. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer. This process can take from 18 to 36 hours. A multi-year initiative was approved in the 2015 Business Plan in order to reduce the number of substation transformers on the "N-1 Distribution Transformer" list.

The Innovation Drive 428-1 transformer was selected as a high priority "N-1 Distribution Transformer" candidate because of its size, the large number of customers served, the high 2015 actual winter loads on the transformer (44.3MVA; 118.8% of nameplate capacity), and the attractive benefit-cost ratio of the project. In the event of a failure of Innovation Drive 428-1 under high load conditions, 1,700-2,100 customers are at risk of an extended outage during a winter substation contingency event (estimated to be a minimum of 24 hours for this station). The scope and cost of the identified substation improvements, when compared to other more expensive projects requiring substation steel and breakers, result in an attractive benefit-cost ratio while helping satisfy the goal of the "N-1 Distribution Transformer" initiative. The scope is relatively minimal and it removes Innovation Drive 428-1 from the "N-1 Distribution Transformer" list.

Innovation Drive substation is located on the north side of Lexington, KY and contains a 20/37.3 MVA, 138-12kV transformer (Innovation Drive 428-1) and a 10/14 MVA, 138-12kV transformer (Innovation Drive 428-2). The Innovation Drive 428-1 winter peak load of 34.9 MVA that occurred in 2011 increased to 44.3MVA (118.8% of the nameplate capacity) in 2015 during the "Arctic Blast" event, an average increase of 6.1% per year. Because of these peak load levels, planned substation work must be carefully scheduled during off-peak periods as an unplanned outage during heavy load conditions could result in an extended outage for 1,700-2,100 residential customers. There is not sufficient transformer and circuit capacity in the Innovation Drive 428-2 transformer and the other surrounding substations (Viley Road, Haefling, Beltline) to provide full contingency support for the loss of the Innovation Drive 428-1 transformer. The recommended improvement is to replace the existing Innovation Drive 428-2 transformer with a 20/37.3 MVA unit in order to remove the Innovation Drive 428-1 transformer from the N-1 Distribution Transformer list. The 138-12kV 10/14MVA transformer removed on this project will be moved to spare inventory in the Danville area and serve as the back-up for Lockport and Lebanon West Substations.

A Transmission Service Request (TSR) was submitted to TranServ International to determine the impact of the project on the transmission system. TranServ International determined that a System Impact Study was not required and the TSR was confirmed.

- **Alternatives Considered**

1. Recommended option: NPVRR ($000s): $1,739
   The recommended option is to replace the existing 10/14 MVA, 138-12kV substation transformer in the Innovation Drive 428-2 substation with a 20/37.3 MVA, 138-12kV substation transformer, and to implement distribution related circuit upgrades as needed to utilize the increased capacity. The total estimated cost is $1,344k.

2. Do nothing option: NPVRR ($000s): $0
   The Innovation Drive 428-1 transformer will remain on the "N-1 Distribution Transformer" list where customers may remain without service for an extended time period in the event of a transformer failure during high load periods.

3. Alternative 2: NPVRR ($000s): $5,091
   This alternative considers the installation of a new substation transformer, steel structures, breakers, transmission poles, and distribution conductor improvements at an existing site (e.g. Haefling) or at a new site in the area that is yet to be identified. The cost of any new substation construction and associated conductor improvements could easily exceed $4,000k or more, and as a result, is not recommended because it far exceeds the cost of the recommended option.

Project Description

- **Project Scope**

  - Substation project #146708 - $888k (2015); $397k (2016); $1,285k (total)
    - Innovation Drive 428-2: Replace the existing 10/14 MVA, 138-12kV transformer with a 20/37.3 MVA, 138-12kV transformer; perform other associated work as necessary.
  - Distribution project #146707 - $59k (2015); $0k (2016); $59k (total)
    - Install 225' of new distribution conductor plus a new air break switch to allow load transfers from Innovation Drive 428-1 to Innovation Drive 428-2.
  - Transmission: No transmission work is necessary.

- **Project Timeline**

  - May 2015: Open project.
  - May-Jun 2015: Perform engineering design related tasks; order and purchase major substation equipment; order distribution materials.
  - Jul-Sep 2015: Perform below grade site preparation as necessary for substation transformer upgrade.
  - Oct-Dec 2015: Finalize below grade site preparation, review protection coordination and relay settings, receive or accrue major substation equipment; install distribution pole, conductors, and switch.
  - Jan-Jun 2016: Receive and install 37.3MVA 138-12.47kV transformer (could be 52wk lead time on bid transformer) and new bus to switchgear.
  - Jun-Sep 2016: Finalize substation installation, site cleanup, final checkout and commissioning.

- **Project Cost**

  The total estimated cost of the project is $1,344k. The substation and distribution cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% of contingency ($134k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - The substation transformer will be bid using established Supply Chain procedures.
  - Bids for other substation material and/or labor will be prepared, if needed, following established Supply Chain procedures.

Budget Comparison and Financial Summary

Financial Detail by Year - Capital ($000s)	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	947	357			1,304
2. Cost of Removal Proposed		40			40
3. Total Capital and Removal Proposed (1+2)	947	397	-	-	1,344
4. Capital Investment 2015 BP					-
5. Cost of Removal 2015 BP					-
6. Total Capital and Removal 2015 BP (4+5)	-	-	-	-	-
7. Capital Investment variance to BP (4-1)	(947)	(357)	-	-	(1,304)
8. Cost of Removal variance to BP (5-2)	-	(40)	-	-	(40)
9. Total Capital and Removal variance to BP (6-3)	(947)	(397)	-	-	(1,344)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed					-
2. Project O&M 2015 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The 2015 Business Plan includes $2.5M in 2015 and $2.563M in 2016 as a part of the approved "N-1 Distribution Transformer" initiative. The estimated $1,344k for the Innovation Drive project will be reallocated from this project through the Corporate RAC process.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 94
Contract Labor:	$ 94
Materials:	$ 743
Local Engineering:	$ 140
Burdens:	$ 136
Transportation:	$ 3
Contingency:	$ 134
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 1,344

Financial Analysis - Project Summary ($000)	2015	2016	2017	2018	2019	Life of Project
Project Net Income	(11.00)	(25.00)	55.00	73.00	67.00	1,283.00
Project ROE	-4.40%	-4.10%	8.00%	11.10%	10.80%	10.20%

- **Assumptions**
  - The estimated cost of the substation transformer will be comparable to the actual cost obtained through the formal bid process.
  - The project unknowns will not exceed the estimated contingency amounts.
  - Project will be completed in approximately 18 months after Investment Committee approval.

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

- **Risks**
  - Without this project, a failure of the Innovation Drive 428-1 transformer could result in potentially long outage durations for existing and future customers in the event of a transformer failure during high load periods.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Innovation Drive Substation N-1 Distribution Transformer project for $1,344k in order to provide the additional substation and circuit capacity necessary to restore service to all customers in the event of a transformer failure during high load periods at Innovation Drive 428-1, without the need to install a portable transformer.

Investment Proposal for Investment Committee Meeting on: April 29, 2015

Project Name: Lakeshore Substation N-1 Distribution Transformer Enhancement

Total Expenditures: $2,763k (including $276k of contingency)

Project Number(s): Distribution Substations: 146602, Distribution Lines: 146606
Transmission: 137756

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Burns/Beth McFarland

Executive Summary

Electric Distribution requests approval for funding to complete the distribution substation improvements and associated minor transmission and distribution line work required to remove the KU Lakeshore substation from the "N-1 Distribution Transformer List".

The N-1 Distribution Transformer 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 located in the near-by vicinity. Complete restoration to all customers served from the transformer would require either replacement of the failed transformer or installation of a portable transformer.

The Lakeshore substation is located in the southeastern portion of Lexington, KY and serves a large number of customers (5,100). For a significant portion of the year, circuit configurations and heavy loading on nearby substations and circuits prevent service from being restored to all customers served from Lakeshore substation in the event of a substation transformer failure during heavy load conditions. Service to these customers will remain out until the failed transformer is replaced or a portable is installed. The recommended option to mitigate this exposure is to install a second 69-12kV 37.3MVA transformer at the Lakeshore substation. This will provide the necessary capacity to restore service to all customers at any time during the year in the event of a transformer failure during high load periods, without the need to install a portable transformer – a process that typically requires 18-36 hours. Installation of the second transformer will also provide additional capacity for load growth and eliminate the impending normal service overload of the existing transformer during extreme weather events. In addition to the recommended project, other alternatives were considered which included the installation of additional transformer capacity in existing substations and the construction of a new substation in the area. These considerations were eliminated due to cost.

This project is scheduled to begin in May 2015 with completion in December 2016. Minor transmission and distribution line work will also be required.

The estimated total project cost is $2,763k. The transmission cost of $294k is in the transmission budget. The 2015 Business Plan (BP) includes a total of $10.4M in 2015-2018 as a part of the approved "N-1 Distribution Transformer" initiative. The estimated $2,469k ($1,600k-2015; $869k-2016) in distribution substation and line costs for the Lakeshore Substation project will be reallocated from this project through the Corporate RAC process.

Background

The Company's "N-1 Distribution Transformer" 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 in the near-by vicinity. Complete restoration to all customers would require either replacement of the failed transformer or installation of a portable transformer. This process can take from 18 to 36 hours. A multi-year initiative was approved in the 2015 Business Plan in order to reduce the number of substation transformers on the "N-1 Distribution Transformer" list.

One of the highest priority N-1 Distribution Transformers is the Lakeshore 37.3MVA 69-12kV substation, located in southeast Lexington. The Lakeshore transformer was selected as a priority "N-1 Distribution Transformer" candidate because of its size, the large number of customers served (5,100), the high actual winter loads on the substation (50.3MVA; 135% of nameplate capacity), and the attractive benefit-cost ratio of the project. In the event of a transformer failure under heavy load conditions, a significant portion of the customers fed from the Lakeshore transformer would not be restored until the transformer is replaced or a portable is installed (estimated to be a minimum of 24 hours for this station). The project also has a very high benefit-cost ratio because the scope is relatively minimal and it removes multiple transformers from the "N-1 Distribution Transformer" list (Lakeshore, FMC).

The Lakeshore substation is situated adjacent to the very high-profile, fast growing Hamburg area and has circuit ties to FMC and Bryant Road substations. Planned work on this substation, including routine substation maintenance, currently requires the installation of a portable transformer which is an expensive and time consuming process. An unplanned outage on the Lakeshore substation during high load periods would result in an extended outage to a portion of the 5,100 customers in this highly visible area where key customers include the St. Joseph East hospital and surrounding medical community. The number of customers that could not be restored varies and is dependent on the loading on Lakeshore substation and surrounding substations at the time of an outage. During extreme loading periods, the percentage of customers without service during a transformer failure is estimated to be as high as 75%.

The Lakeshore substation is winter peaking and although a capacity addition due to normal load growth is not forecasted in the next five years, the substation frequently requires load shifting during extreme temperatures to Bryant Road 1 substation to prudently manage transformer loading. During extreme winter events, constant oversight by the Distribution Control Center and Distribution Planning is required in this area to avoid transformer and circuit overloads which exceed equipment emergency ratings. Also, summer loading on the Bryant Road transformer sometimes requires load shifting back to the Lakeshore substation. The addition of a second transformer at Lakeshore provides the additional benefit of completely eliminating these operational concerns as well as reducing the peak loading on the existing transformer. A second transformer at Lakeshore will also remove the FMC substation from the "N-1 Distribution Transformer" list. Additionally, this project in combination with the planned installation of the second Hume Road transformer (projected 2017 completion in the 2015 BP) will also remove the Liberty Road transformer from the "N-1 Distribution Transformer" list.

A Transmission Service Request (TSR) was submitted to TranServ International to determine the impact of the project on the transmission system on 12/19/14. Transerv has not completed the Facility Study to determine the estimated cost of transmission improvements, but associated transmission costs are not expected to significantly deviate from the $294k allocated in the transmission budget for this project.

- **Alternatives Considered**
  1. Recommended option: NPVRR: ($000s) $3,550
     The recommended option is to install a second 37.3MVA transformer at the Lakeshore substation with necessary 69kV and 12kV steel, one 69kV breaker, one 15kV low side breaker, one 15kV tie breaker and three 15kV line breakers, and associated transmission and distribution circuit construction. The total estimated cost is $2,763k.

  2. Do nothing option: NPVRR: ($000s) $ 0
     Two transformers will remain on the "N-1 Distribution Transformer" list where customers may remain without service for an extended time period in the event of a transformer failure during high load periods. Also, failure to complete this project could also result in an overloaded substation transformer and excessive circuit loadings at Lakeshore substation during extreme temperatures and decreased reliability in the areas served by the substation.

  3. Next best alternative: NPVRR: ($000s) $8,528
     Construct new 138-12kV 37.3MVA substation on EKP 138kV transmission line southeast of the Lakeshore substation. This option would place a substation in a desirable location on the distribution system, but the cost would be significantly higher for 138kV equipment and there would be additional costs associated with 138kV service from EKP (the only other nearby transmission). A property purchase would be required. The total estimated cost is $6,700k is based on the cost of a recent similar project (Hume Rd).

Project Description

- **Project Scope**

  - Substation project #146602- $1,600k (2015); $700k(2016); $2,300k (total)
    - Lakeshore 853-2: Install 1-37.3MVA 69-12kV transformer, 1-69kV breaker, 5-15kV breakers, high and low side steel, and associated equipment.

  - Distribution Lines project #146606 $169k (2016)
    - Relocate circuit 132 and circuit 152 exits to new low side steel.

- Transmission Lines project #137756 $98k (2015); $196k (2016); $294k (total)
  - Replace two concrete poles with steel poles to allow distribution underbuild enhancements.

- **Project Timeline**

  - May 2015: Open project.
  - May-Jun 2015: Perform engineering design related tasks; order and purchase major substation equipment. Perform miscellaneous site preparation.
  - Jun-Sept 2015: Order transmission poles and materials.
  - Jan-Jun 2016: Complete grading, foundations and construction of high and low side steel. Replace two transmission poles and transfer circuits.
  - Jun-Oct 2016: Relocate distribution circuits 132 and 152 exits to new steel. Install 37.3MVA 69-12.47 transformer, one 69kV breaker, three 1200 amp line breakers, one 2000 amp tie breaker, one 2000 amp low side breaker and remaining substation major components.
  - Oct-Dec 2016: Substation site cleanup, miscellaneous construction completion. Commission substation.

- **Project Cost**

  The total estimated cost of the project is $2,763k. Cost estimates are consistent with the "Conceptual Level 1" engineering design designation. There is an estimated 10% contingency ($276k) incorporated into the project cost estimates.

Economic Analysis and Risks

- **Bid Summary**
  - The substation transformer and breakers will be ordered using existing contracts and following established Supply Chain procedures.
  - Bids for other substation and transmission material and/or labor will be prepared, if needed, following established Supply Chain procedures.

Budget Comparison and Financial Summary

Financial Detail by Year - Capital ($000s)	2015	2016	2017	Post 2017	Total
1. Capital Investment Proposed	1,671	986			2,657
2. Cost of Removal Proposed	27	79			106
3. Total Capital and Removal Proposed (1+2)	1,698	1,065	-	-	2,763
4. Capital Investment 2015 BP	98	196			294
5. Cost of Removal 2015 BP					-
6. Total Capital and Removal 2015 BP (4+5)	98	196	-	-	294
7. Capital Investment variance to BP (4-1)	(1,573)	(790)	-	-	(2,363)
8. Cost of Removal variance to BP (5-2)	(27)	(79)	-	-	(106)
9. Total Capital and Removal variance to BP (6-3)	(1,600)	(869)	-	-	(2,469)

Financial Detail by Year - O&M ($000s)	2015	2016	2017	Post 2017	Total
1. Project O&M Proposed					-
2. Project O&M 2015 BP					-
3. Total Project O&M variance to BP (2-1)	-	-	-	-	-

The funding for the Transmission Lines project was budgeted in the 2015 Business Plan. The 2015 Distribution Business Plan includes $2.5M in 2015 and $2.563M in 2016 as part of the approved "N-1 Distribution Transformer" initiative. The estimated $2.469M (excluding Transmission amount) for the Lakeshore project will be reallocated from this project through the Corporate RAC process. There is $47k in 2015 that will be funded from other projects, for a minor overage between the two N-1 Distribution Transformer projects compared to budget.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 283
Contract Labor:	$ 540
Materials:	$1,041
Local Engineering:	$ 263
Burdens:	$ 359
Transportation:	$ 1
Contingency:	$ 276
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 2,763

Financial Analysis - Project Summary ($000)	2015	2016	2017	2018	2019	Life of Project
Project Net Income	(20.00)	(51.00)	112.00	149.00	138.00	2,640.00
Project ROE	-4.40%	-4.30%	8.00%	11.10%	10.80%	10.20%

- **Assumptions**
  - Load growth in the Lakeshore area will continue at a greater than average rate due to the fast growing Hamburg area. Estimates are based on recently completed work that is similar in scope.
  - Project will be completed in approximately 18 months after Investment Committee approval.

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

- **Risks**
  Failure to complete the transformer addition at the Lakeshore substation by the recommended date could result in decreased area reliability and potentially long outage durations for existing and future customers in the event of a transformer failure during high load periods. During extreme weather events, there is also a risk of substation transformer and circuit overloads that could lead to equipment and material failure.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the project for $2,763k to provide the necessary capacity to allow timely restoration of all customers in the event of a transformer failure at either Lakeshore or FMC substations, even under peak loading conditions, without the need to install a portable transformer. The project also provides additional capacity for load growth and alleviates the possibility of transformer and circuit overloads which exceed emergency equipment ratings during extreme weather conditions.

Investment Proposal for Investment Committee Meeting on: July 27, 2016

Project Name: _N1DT Contingency Program - KU Spare and Mobile Transformers

Total Expenditures: $_6,135k (Including $292k of contingency) _

Project Number(s): 151598

Business Unit/Line of Business: __Electric Distribution Operations_

Prepared/Presented By: _Tony Durbin/Beth McFarland_

Executive Summary

Electric Distribution Operations (EDO) proposes to secure funding to implement an enhanced spare and mobile transformer strategy in 2016-2017 to support the N-1 Distribution Transformer Contingency Program (N1DT) at KU. The N1DT program is a planned 15 year, approximately $175M program designed to enhance the LG&E/KU customer experience through improved reliability and reduced exposure to high consequence, long duration service interruptions resulting from substation power transformer failures. The N1DT program includes substation/circuit upgrades, capacity additions, improved spare and mobile transformer strategies, and other enhancements for distribution substations. It will provide contingency capacity for larger substation transformer failures and for reducing expected outage durations on smaller transformers where providing full redundancy is not considered cost effective.

EDO's N1DT program incorporates a multi-tiered approach based on transformer size. The strategy adds transformer and circuit contingency and/or implements other proactive steps to reduce outage duration based on the anticipated value added in terms of customers impacted, load at risk, and implementation costs. Substation transformer failure consequences from the perspective of customers and load affected generally increase with the size of the transformer. A tiered contingency approach based on transformer size allows LG&E/KU to cost effectively extend the benefits of the N1DT program to more customers.

This proposed project provides for enhancements to the spare and mobile transformer plan for more rural areas of the KU service territory to reduce outage times for customers where it is not cost effective to build permanent contingency into the system. Specifically, this project includes the purchase of two mobile transformers, two small spare transformers, capital refurbishment of existing spares, and construction of basic storage facilities to store the spare and mobile equipment closer to the substations that they are intended to back up.

The proposed project will begin in 2016 and be completed in 2017, and is not funded in EDO's approved 2016 Business Plan (BP). Requested 2016 funding was approved at the Corporate RAC in May and June. The 2016 Business Plan included $7M and $10M in 2017 and 2018 for N1DT projects and an additional $2.2M and $200k in 2017 and 2018 for the purchase of a large portable transformer. In EDO's 2017 proposed BP, the existing N1DT and portable transformer projects will be reduced in 2017 and 2018 to cover the majority of this funding. $545k will be incremental to the N1DT program in 2017 in the Business Plan.

Background

LG&E/KU is implementing an N1DT (N-1 Distribution Transformer) Contingency Program to enhance the LG&E/KU customer experience through improved reliability and reduced exposure to high consequence, long duration service interruptions due to failure of a substation power transformer.

The N1DT Program is a fifteen-year (2015–2029) plan that includes $175M in funding to implement substation/circuit upgrades, capacity additions, improved spare and mobile transformer strategies, and other enhancements for distribution substations and circuits. In the more densely populated urban areas where transformers typically serve more customers, are larger in size and circuits usually have ties to other sources, adding additional contingency and capacity into the system to reduce outage duration is cost effective. In less dense areas of the KU system where transformers typically serve fewer customers, are smaller in size and circuit ties are few or non-existent, it is often not practical or cost effective to build in contingency for every substation transformer. In these areas a spare and mobile transformer strategy is the most effective solution to reduce outage duration in the event of a substation transformer failure. Effectively implementing this strategy requires an adequate number of spare and mobile transformers be located in close proximity to the transformers in each operating area to eliminate the time associated with transporting mobile or spare transformers from other areas.

A three-tiered N1DT restoration approach is being implemented according to the size of the transformer at risk.

Class I Contingency:
For transformers sized at or below base 3750kVA, typically serving 300 customers or less, a Class I contingency plan is applied. This program will increase the number of spare transformers as well as redistributing all spares throughout the state to reduce transportation and replacement time. Transformers sized at or below 3750kVA, typically can be replaced faster than a mobile transformer can be installed. There are 136 transformers rated 3750kVA or lower in the LG&E/KU service territory.

Class II Contingency:
For transformers at or between base 5MVA and base 10MVA, typically serving less than 1000 customers, Class II contingency is applied. Spare transformers of this size as well as a mobile transformer will be made available in the local area ready for transport. There are 310 transformers rated between 5MVA and 10MVA in the LG&E/KU service territory.

Class III Contingency:
For transformers base 12MVA and greater, typically serving greater than 2500 customers, Class III contingency is applied. Class III contingency will be accomplished by investment in circuit upgrades, capacity additions, or other system enhancements. There are 269 transformers rated 12MVA or greater in the LG&E/KU service territory. Until Class III contingency is implemented in a targeted substation, the mobile/spare strategy will be utilized.

KU currently utilizes two mobile transformers (7.5MVA and 30MVA), both normally located in the Lexington area. Two 15MVA mobiles are recommended for purchase to improve the contingency plan, with one transformer each being located in the eastern (Pineville) and western (Earlington) portions of the KU service territory. Currently, KU also uses mobiles to maintain service when taking power transformers out of service for maintenance, and it is not uncommon to have both mobiles in service at the same time and unavailable to be used for transformer failures. Additional mobiles will benefit Substation Construction & Maintenance in providing more flexibility to obtain such outages while still maintaining preparedness to address an unexpected transformer failure.

For 2016-2017, the following actions are proposed to continue implementation of EDO's N1DT program:

1. Purchase two (2) Mobile Transformers. Each mobile will be rated 15 MVA, 69X34.5 KV DELTA – 13.09X4.36 KV WYE GRD. These mobiles provide the ability to handle various high and low side voltage configurations.

2. Purchase two (2) new spare transformers.
   a. 2.5/3.5 MVA, 67-13.09KV for Earlington
   b. 0.5 MVA, 23-7.2KV for Big Stone Gap

3. Enhance the Pineville storage lot for storage of five (5) additional spare transformers and one new mobile transformer. The enhancements will include construction of concrete foundations for spares, a shelter for the mobile, and installation of AC circuits for cabinet heaters. A shelter will also be constructed for the second mobile transformer, which will be stored in Earlington.

4. Relocate nine (9) spare transformers so that they are stored in closer proximity to relevant substations. (This is $90k OPEX, not capital.)

5. Purchase new bushings for five (5) spare transformers that currently do not pass power factor tests. These bushings will allow for those units to become viable spares.

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

1. Recommendation: NPVRR: ($000s) $8,097
Purchase two new 15 MVA mobile transformers, two new spare transformers, and five sets of new bushings needed to refurbish existing spare transformer stock for use. This

recommendation includes the necessary work to relocate and store targeted transformers closer to affected areas. Ensuring the availability of mobile and spare transformers closer to covered areas is expected to reduce the risk of having to transport a transformer from another area which increases outage duration by an expected six (6) hours. The estimated total cost of this option is $6,135k.

2. Do Nothing: NPVRR: ($000s) $9,702
The Do Nothing option would result in an insufficient number of adequately sized mobile and spare transformers to successfully and consistently implement EDO's N1DT contingency program which was designed to reduce outage durations associated with 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.

   A tally of all distribution substation transformers in the Earlington/Pineville areas that are sized above base-3750 KVA yields 166 units with 129 of them on the "At Risk" list. The average annual peak load for the 129 units at risk is 6726 KVA. Over the past 10 years, KU has averaged 1.6 transformer failures (> base 3750 KVA) per year in the combined Earlington/Pineville areas.

   Thus, it would be prudent to be prepared, from an emergency response standpoint, for at least one failure per year that would benefit from an enhanced spare and portable strategy in the combined Earlington/Pineville areas. If a spare transformer is utilized instead of a portable transformer, we can assume an average of six hours extra time to energize a spare compared to energizing a portable, even longer if the spare has to be transported from another operating area. This delay is primarily a result of prepping the spare unit for shipment and set up/teardown of the crane. A six 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.

   The calculation of the cost of unserved energy yields:
   (1.0 Failure) X (6726 KVA) X (6 Hours) X ($17.20/kW-Hr) = $694k per year.

3. Next Best Alternative(s): NPVRR: ($000s) N/A
No other alternative to speeding service restoration at Class I and II N1DT substations is seen as viable or cost effective. Of the 446 Class I and II transformers, 347 of them are considered at risk. The only alternative to reduce the outage duration for these 347 Class I and Class II N1DT transformers would be to follow the approach for Class III transformers and add transformer capacity and other improvements to remove some or all of them from the N1DT list. The cost could exceed $1.2 billion to remove all 347 Class I and II stations from the N1DT list using an estimated N1DT Class III project cost of $3.5M/station.

Project Description

- **Project Scope and Timeline**

8/1/2016	Purchase two (2) 15 MVA, 69x34.5-13.09x4.36 kV mobile transformers and (2) spare transformers
12/31/2016	Receive spare transformers
7/1/2017	Purchase and receive transformer bushings required for spares
8/1/2017	Receive mobile transformers
9/1/2017	Complete construction of Pineville and Earlington storage enhancements
10/1/2017	Complete relocation of spare transformers (this is OPEX)

- **Project Cost**

The estimated project cost for 2016-2017 is $6,135k; $4,954k to be incurred in 2016, and $1,181k in 2017. Additionally, there will be $90k of OPEX costs associated with relocating nine (9) spare transformers in 2017.

This project is estimated with 5% contingency ($292k).

The estimated burdened costs for the various components of this project are:

KU Mobile Transformer 1	$2,536k
KU Mobile Transformer 2	$2,536k
KU Spare Transformer 1	$178k
KU Spare Transformer 2	$12k
Enhance Pineville storage lot	$415k
Construct Earlington shelter	$107k
Purchase bushings	$59k
Contingency	$292k
Total Cost	$6,135k

The $90k of OPEX required to relocate existing spare transformer to Pineville and Earlington will be reallocated from other projects included in the proposed 2017 BP.

Economic Analysis and Risks

- **Bid Summary**

Competitive bids have already been solicited from three portable manufacturers. One manufacturer did not bid and a second manufacturer did not comply with the design specification. Although the Award Recommendation has not been completed, the portables will be awarded to the third manufacturer, which is Delta Star. Pricing from Delta Star has been incorporated into these estimates.

Costs for two spare transformers and bushings will be bid and purchased using established supply chain procedures and will be obtained later per the Project Scope and Timeline above.

- **Budget Comparison and Financial Summary**

Financial Detail by Year - Capital ($000s)	2016	2017	2018	Post 2018	Total
1. Capital Investment Proposed	4,954	1,181			6,135
2. Cost of Removal Proposed					-
3. Total Capital and Removal Proposed (1+2)	4,954	1,181	-	-	6,135
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)	(4,954)	(1,181)	-	-	(6,135)
8. Cost of Removal variance to BP (5-2)	-	-	-	-	-
9. Total Capital and Removal variance to BP (6-3)	(4,954)	(1,181)	-	-	(6,135)

Financial Detail by Year - O&M ($000s)	2016	2017	2018	Post 2018	Total
1. Project O&M Proposed		90			90
2. Project O&M 2016 BP					-
3. Total Project O&M variance to BP (2-1)	-	(90)	-	-	(90)

This project was not funded in EDO's approved 2016 Business Plan (BP). The proposed project will require funding of $4954k in 2016 and $1181k in 2017 for a total project cost of $6135k. Requested 2016 funding will be approved at the Corporate RAC. The 2016 Business Plan incorporated $7M and $10M in 2017 and 2018 for N1DT projects. The approved 2016 BP also included an approved project for the purchase of a large portable transformer for $2.2M in 2017 and $200k in 2018.

$2.4M in funding for the planned portable transformer purchase will be reallocated to this project and pulled forward into 2016 with an offsetting reduction in the proposed 2017 BP in 2017 and 2018. Additional N1DT funds in the amount of $100k in 2017 and $2,364k in 2018 will also be pulled forward from planned N1DT funding into 2016, also with offsetting reductions in 2017 and 2018. This results in a total of $4,864k in pull forward funding that will see offsetting reductions in the 2017 BP. Following the development of a funding plan and the proposed 2017 BP, higher than expected bids were received for the portable transformers. These higher costs along with late revisions to the scope of work left a funding shortfall of $90k in 2016 and $545k in 2017. Incremental funding in 2016 has been approved by the Corporate RAC. The incremental amount in 2017 is incorporated into the proposed 2017 BP.

The $90k OPEX in 2017 required to relocate existing spare transformers was not included in the approved 2016 BP and will be funded by reallocations from other projects included in the 2017 BP.

Financial Summary ($000s):

Discount Rate:	6.5%
Capital Breakdown:	
Labor:	$ 20
Contract Labor:	$ 440
Materials:	$4,474
Transportation:	$ 4
Local Engineering:	$ 830
Burdens:	$ 75
Contingency:	$ 292
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 6,135

Financial Analysis - Project Summary ($000)	2016	2017	2018	2019	2020	Life of Project
Project Net Income	-	195.00	305.00	293.00	281.00	5,804.00
Project ROE	0.00%	3.40%	8.00%	10.00%	10.00%	9.40%

- **Assumptions**

  KU's installed transformer base ages and failure rates will continue at current rates or possibly increase, requiring an adequate mobile transformer and spare transformer fleet to meet customer commitments. The useful life of a mobile transformer typically exceeds 40 years, and the useful life of typical power transformers normally exceeds 30 years. The current average age of KU’s transformers is 40 years old.

- **Environmental**

  No environmental issues are known at this time. Oil containment will be installed as necessary at the Pineville storage lot.

- **Risks**

  In the event of a transformer failure, the unavailability of a suitably sized mobile unit or spare unit could put thousands of customers at risk for an extended outage, or poor voltage regulation for extended periods.

Conclusions and Recommendation

EDO recommends Investment Committee authorization of $6,135k for the KU Spare and Mobile Transformers component of the N1DT Contingency Program, to enhance its contingency plan for failed substation transformers at KU's Class I and II N1DT stations.

<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

Investment Proposal for Investment Committee Meeting on: February 28, 2018

Project Name: Plainview Distribution Substation Transformer Contingency Project

Total Expenditures: $11,073k (includes $1,007k of contingency)

Project Number(s): Distribution Substations 148490, Distribution Lines 148484, Transmission Lines 151752

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Kevin Patterson/Dan Hawk

Executive Summary

Electric Distribution Operations (EDO) - Electrical Engineering and Planning (EEP) seeks funding authority for distribution substation, distribution circuit, and transmission line improvements in and near the LG&E Plainview Substation. The Plainview Substation is located near the intersection of Shelbyville Road and Hurstbourne Parkway and directly serves approximately 6,700 commercial and residential customers. The purpose of this proposed project is to provide year-round full contingency to serve load at the Plainview TR1, Hurstbourne TR1, Hurstbourne TR2 and Aiken TR1 transformers in support of the Company's Distribution Substation Transformer Contingency Program (N1DT). This will be accomplished by increasing substation capacity at the Plainview Substation through the installation of a second 44.8 MVA transformer. Additionally, transmission and distribution reliability enhancements will be made through substation and circuit upgrades. This project will also improve the reliability of transmission service to the Plainview Substation with the installation of a ring-bus to reduce the likelihood of a transmission related outage.

Approval is requested in the amount of $ 11,073k ($6,088k-2018, $4,985k-2019) to complete the Plainview Distribution Substation Transformer Contingency project. This project is included in the 2018 EDO and Transmission Business Plan (BP) with a total funding level of $8,876k ($4,239k-2018, $4,437k-2019), and is scheduled to begin in the first quarter of 2018 with completion in December 2019. The total cost of the project is more than the budgeted amount due to:

1) the scope of the distribution circuit improvements were altered to reduce impact along Hurstbourne Parkway after the project details were reviewed,
2) the substation cost estimates have increased due to higher equipment costs, contractor expenses and EPCM costs, and
3) additional transmission breakers and line work were added to the scope to provide enhanced transmission reliability to the substation and accommodate distribution work along Shelbyville Road.

The 2018 overrun of $1,849k was approved, through the February Corporate RAC processes. The 2019 budget shortfall of $548k will be addressed in the 2019 BP.

Background

The Distribution Substation Transformer Contingency Program (N1DT) 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 could take up to 36 hours depending on the specific location.

Plainview TR1, Aiken TR1, Hurstbourne TR1 and Hurstbourne TR2 have been identified as part of the N1DT Contingency Program.

Substation Transformer	Customers	Capacity (MVA)	2016 Summer Load (Actual MVA)	2020 Summer Load (Forecasted MVA)
Plainview TR1	6,664	44.8	30.9	31.1
Aiken TR1	5,021	44.8	29.8	30.0
Hurstbourne TR1	6,212	44.8	31.5	31.7
Hurstbourne TR2	3,966	44.8	30.6	30.7

Note: The 2016 Summer Load amounts are 10-15% lower than load levels observed in prior peak years (2010-2011) due to the milder summer conditions. During extreme hot weather, loads can be expected to be higher than observed 2016 levels.

The Plainview Substation is adjacent to both the Aiken and Hurstbourne Substations, has numerous tie circuits, has available space for expansion, and provides the maximum benefit to multiple substations in the N1DT Contingency Program. The installation of a new 44.8 MVA substation transformer and associated improvements in the Plainview Substation is proposed in order to provide the four existing 44.8 MVA transformers at Plainview, Aiken and Hurstbourne with contingency. Over 20,000 customers are served from these four existing transformers.

- **Alternatives Considered**

1. Recommended Option: NPVRR: $12,824k
   The recommended option is to install a new 138/12kV, 44.8 MVA transformer and all associated substation equipment in the Plainview Substation. Also included are transmission and distribution line improvements to provide year round contingency for four area transformers while enhancing the reliability of transmission service to this station. Transmission Reliability recommends the installation of a high side ring-bus because of the 6,664 existing customers at the Plainview Substation and significant transmission line exposure. The addition of a ring-bus eliminates the possibility of a partial substation outage due to a single transmission line fault. The estimated capital cost of this option is $11,073k.

2. Do Nothing Option: NPVRR: $ 12,967k
   This project is consistent with the objectives of the Company's Distribution Substation Transformer Contingency Program. The "do nothing" option was evaluated using standard

corporate metrics to quantify the "Cost of Unserved Energy" benefit for providing contingency throughout the year for four areas substation transformers. Without adequate contingency capacity, the failure of any of the four transformers addressed by this project could result in an extended outage for some customers of up to 24 hours until the transformer can be replaced or a mobile transformer installed. Using a 5% annual probability of a failure of any of the four transformers, a "Cost of Unserved Energy" of $17.20/kwh, a reduction in outage duration of 24 hour outage (48 hour outage at Aiken due to substation size constraints) with the loads going unserved at Plainview (10.0 MW), Aiken (6.0 MW), Hurstbourne 1 (5.0 MW), and Hurstbourne 2 (5.0 MW), the "Cost of Unserved Energy" is approximately $660k annually. The estimated capital cost of this option is $0k.

3. Alternative 1: NPVRR: $16,840k
This option considers the replacement of Aiken TR2 (28.0 MVA) with a larger unit (44.8 MVA) and adding a third 44.8 MVA transformer at Hurstbourne Substation. Extensive circuit additions along Hurstbourne Parkway and Shelbyville Road (including replacement of multiple transmission structures) would also be required. This option is more expensive, is a less effective system design, and results in less distribution reliability improvements than the recommended option and is not recommended. The estimated capital cost of this alternative is $14,500k.

Project Description

- **Project Scope**
  - Substation project #148490: estimated cost $6,565k ($3,519k-2018; $3,046k-2019).
    - Install a new 44.8 MVA, 138-12 kV transformer, 138kV ring-bus, steel package, switchgear, and associated equipment in the Plainview Substation.
  - Distribution project #148484: estimated cost $3,549k ($2,429k-2018; $1,120k-2019).
    - Install approximately 10,000' of 795 AAC, 795 AAC spacer cable, and 1000 Aluminum underground conductor as needed for four (4) new distribution exit circuits and install additional tie switches. Approximately 2500' of new conduit with manholes will also be installed. Contingency is included to cover uncertainty of easement costs and possible rock removal.
  - Transmission project #151752: estimated cost $959k ($140k-2018; $819k-2019).
    - Install approximately 20 new structures along Shelbyville Road to accommodate additional distribution circuits.

  A Network Integration Transmission Service (NITS) request will be submitted to TranServ International for a new delivery point. Loads will primarily be transferred from the existing Plainview transmission delivery point to the new Plainview delivery point so additional transmission investment is not anticipated.

- **Project Timeline**
  - March, 2018: Open projects.
  - April-May, 2018: Perform substation and transmission engineering design related tasks; order major equipment.

- June-August, 2018: Perform distribution engineering design related tasks for planned 2018 work; order materials.
- September-December, 2018: Complete distribution conductor improvements for planned 2018 work; receive major substation and transmission equipment.
- January-April, 2019: Perform substation site preparation and foundation work; perform distribution engineering design related tasks for planned 2018 work; order materials.
- May-August, 2019: Progress on transmission foundations and pole installation; progress on distribution conductor improvements for planned 2018 work.
- September-November, 2019: Install substation structures and equipment; progress on distribution conductor improvements.
- December, 2019: Complete remainder of substation, transmission, and distribution improvements; commission substation.

- **Project Cost**
  - The total estimated cost of the project is $11,073k. The substation cost estimates are consistent with the "Conceptual Level 1" engineering design designation. The distribution and transmission line cost estimates are consistent with the "Preliminary" engineering design designation and are based on field experience from similar projects. There is an estimated 10% of contingency ($1,007k) 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)	**2018**	**2019**	**2020**	**Post 2020**	**Total**
1. Capital Investment Proposed	6,088	4,949	-	-	11,037
2. Cost of Removal Proposed	-	36	-	-	36
3. Total Capital and Removal Proposed (1+2)	6,088	4,985	-	-	11,073
4. Capital Investment 2018 BP	4,239	4,437	-	-	8,676
5. Cost of Removal 2018 BP	-	-	-	-	-
6. Total Capital and Removal 2018 BP (4+5)	4,239	4,437	-	-	8,676
7. Capital Investment variance to BP (4-1)	(1,849)	(512)	-	-	(2,361)
8. Cost of Removal variance to BP (5-2)	-	(36)	-	-	(36)
9. Total Capital and Removal variance to BP (6-3)	(1,849)	(548)	-	-	(2,397)

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 was identified and funded in the 2018 Business Plan at the following levels: Substation project #148490 $4,929k ($2,988k-2018; $1,941k-2019); Distribution project #148484 $3,297k ($1,111k-2018; $2,186k-2019); Transmission project #151752 $450k ($140k-2018; $310k-2019). The 2018 BP amounts are lower than the requested amount by $2,397k. The 2018 incremental funding was approved through the Corporate RAC process in February 2018, while the remaining amount will be addressed through the 2019 BP process.

Financial Summary ($000s):

Discount Rate:	6.58%
Capital Breakdown:	
Labor:	$ 470
Contract Labor:	$ 3,975
Materials:	$ 3,909
Local Engineering:	$ 898
Burdens:	$ 772
Contingency:	$ 1,007
Transportation:	$ 42
Reimbursements:	($ 0)
Net Capital Expenditure:	$11,073

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution and transmission line improvements are consistent with similar past projects.
  - 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**
  - The cost of the distribution portion of the project could escalate because costs are based on similar completed work for other projects of similar scope and size.
  - Additional private easements will need to be obtained to complete work as planned.
  - The potential for rock removal could increase costs, but should be covered by the contingency included for the Distribution Circuit work estimates.
  - Failure to approve this project could negatively impact the company's ability to provide service to existing customers during planned or unplanned outage events.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Plainview Distribution Substation Contingency Project for $11,073k to provide Distribution Substation Transformer Contingency Program (N1DT) benefits in Louisville, KY.

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	

Investment Proposal for Investment Committee Meeting on: May 30, 2018

Project Name: Pleasure Ridge Distribution Substation Transformer Contingency Project

Total Expenditures: $9,947k (includes $933k of contingency)

Project Number(s): Distribution Substations 155386, Distribution Lines 131715, Transmission Lines 157313

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Alan Black/Dan Hawk

Executive Summary

Electric Distribution Operations (EDO) – Electrical Engineering and Planning (EEP) seeks funding authority for distribution substation, distribution circuit, and transmission line improvements in and near the LG&E Pleasure Ridge Substation. The Pleasure Ridge substation is located near the intersection of Dixie Highway and Atlas Powder Road and directly serves approximately 8,000 commercial and residential customers. The purpose of this proposed project is to provide year-round full contingency to serve load at the Pleasure Ridge TR1, Ashby TR1 and TR2 and Terry TR2 transformers in support of the Company's Distribution Substation Transformer Contingency Program (N1DT). This will be accomplished by increasing substation capacity at the Pleasure Ridge Substation through the installation of a second 44.8 MVA transformer. Additionally, transmission and distribution reliability enhancements will be made through substation and circuit upgrades. This project will also improve the reliability of transmission service to the Pleasure Ridge Substation with the installation of a ring-bus to reduce the likelihood of a transmission related outage.

Approval is requested in the amount of $9,947k ($987k-2018, $6,052k-2019, $2,908k-2020) to complete the Pleasure Ridge Distribution Substation Transformer Contingency project. This project replaces previously planned N1DT projects in the 2018 Business Plan (BP) funded at $987k in 2018. The 2019 and 2020 amounts will be requested as part of the 2019 BP process.

Background

The Distribution Substation Transformer Contingency Program (N1DT) 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 could take 36 hours or longer depending on the specific location.

Pleasure Ridge TR1, Ashby TR1 and TR2 and Terry TR2 have been identified as part of the N1DT Contingency Program.

Substation Transformer	Customers	Capacity (MVA)	2016 Summer Load (Actual MVA)	2020 Summer Load (Forecasted MVA)
Pleasure Ridge TR1	8,063	44.8	32.3	33.5
Ashby TR1	4,262	28.0	21.6	21.8
Ashby TR2	5,352	28.0	22.6	22.8
Terry TR2	5,115	44.8	36.0	38.1

Note: The 2016 Summer Load amounts are 10-15% lower than load levels observed in prior peak years (2010-2011) due to the milder summer conditions. During extreme hot weather, loads can be expected to be higher than observed 2016 levels.

The Pleasure Ridge Substation is adjacent to both the Ashby and Terry Substations, has tie circuits, has available space for expansion, and provides the maximum benefit to multiple substations in the N1DT Contingency Program. The installation of a new 44.8 MVA substation transformer and associated improvements in the Pleasure Ridge Substation is proposed in order to provide the existing 44.8 MVA transformers at Pleasure Ridge and Terry, and the two 28.0 MVA transformers at Ashby with contingency. Over 22,000 customers are served from these four existing transformers.

- **Alternatives Considered**

1. Recommended Option: NPVRR: $10,967k
   The recommended option is to install a new 138/12kV, 44.8 MVA transformer and all associated substation equipment in the Pleasure Ridge Substation. Also included are transmission and distribution line improvements to provide year round contingency for four area transformers while enhancing the reliability of transmission service to this station. Transmission Reliability recommends the installation of a high side ring-bus because of the 8,063 existing customers at the Pleasure Ridge Substation and significant transmission line exposure. The addition of a ring-bus eliminates the possibility of a partial substation outage due to a single transmission line fault. The estimated capital cost of this option is $9,947k.

2. Do Nothing Option: NPVRR: $12,355k
   This project is consistent with the objectives of the Company's Distribution Substation Transformer Contingency Program. The "do nothing" option was evaluated using standard corporate metrics to quantify the "Cost of Unserved Energy" benefit for providing contingency throughout the year for four areas substation transformers. Without adequate contingency capacity, the failure of any of the four transformers addressed by this project could result in an extended outage for some customers of up to 24 hours until the transformer can be replaced or a mobile transformer installed. Using a 5% annual probability of a failure of any of the four transformers, a "Cost of Unserved Energy" of $17.20/kwh, a reduction in outage duration of 24 hour outage with the loads going unserved at Pleasure Ridge (10.365 MW), Ashby TR1 and TR2 (10.939 MW), TE (5.569 MW), the "Cost of Unserved Energy" is approximately $555k annually.

3. Alternative 1: NPVRR: $16,277k
   This option considers the replacement of Terry TR1 (28.0 MVA) with a larger unit (44.8 MVA) and adding a third 28.0 MVA transformer at Ashby Substation. Extensive circuit additions along Dixie Highway (including replacement of multiple transmission structures) would also be required. This option is more expensive, is a less effective system design, and results in less distribution reliability improvements than the recommended option and is not recommended. The estimated capital cost of this alternative is $15,000k.

Project Description

- **Project Scope**
  - Substation project #155386: estimated cost $6,430k ($987k-2018; $3,886k-2019; $1,557-2020).
    - Install a new 44.8 MVA, 138-12 kV transformer, 138kV ring-bus, steel package, switchgear, and associated equipment in the Pleasure Ridge Substation.
  - Distribution project #131715: estimated cost $3,315k ($2,129k-2019; $1,186k-2020).
    - Install approximately 7,600' of 1000MCM UG Conductor, 6,250' of 795 AAC spacer cable, along with additional tie switches. Approximately 2700' of new conduit with manholes will also be installed. Contingency is included to cover uncertainty of easement costs and possible rock removal.
  - Transmission project #157313: estimated cost $202k ($37k-2019; $165k-2020).
    - Install two directly embedded dead end structures and two spans of 1272 kcmil 61 strand AAC into the face of steel.

- **Project Timeline**
  - June, 2018: Open projects.
  - June-December, 2018: Perform substation and transmission engineering design related tasks; order major equipment.
  - June-December, 2018: Perform distribution engineering design related tasks for planned 2019 work.
  - January-July, 2019: Receive major substation equipment.
  - May-June, 2019: Order Transmission material.
  - November-December, 2019: Perform transmission line work.
  - August, 2019-February, 2020: Perform substation site preparation and foundation work; complete distribution engineering design related tasks for planned 2019 work; order materials; start construction.
  - March-September, 2020: Install substation structures and new equipment; install remote-end transmission panels; progress on distribution conductor improvements.
  - October-December, 2020: Complete remainder of substation and distribution improvements; commission substation.

- **Project Cost**
  - The total estimated cost of the project is $9,947k. The substation cost estimates are consistent with the "Conceptual Level 1" engineering design designation. The distribution and transmission line cost estimates are consistent with the "Preliminary" engineering design designation and are based on field experience from similar projects. There is an estimated

contingency of $933k 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 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)	2018	2019	2020	Post 2020	Total
1. Capital Investment Proposed	987	6,010	2,885	-	9,882
2. Cost of Removal Proposed	-	42	23	-	65
3. Total Capital and Removal Proposed (1+2)	987	6,052	2,908	-	9,947
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)	(987)	(6,010)	(2,885)	-	(9,882)
8. Cost of Removal variance to BP (5-2)	-	(42)	(23)	-	(65)
9. Total Capital and Removal variance to BP (6-3)	(987)	(6,052)	(2,908)	-	(9,947)

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 replaces N1DT projects previously identified and funded in the 2018 Business Plan to cover 2018 funding. The reallocation of funding for 2018 was approved in the Corporate RAC process. Funding for 2019 and 2020 will be included in the proposed 2019 Business Plan.

Financial Summary ($000s):

Discount Rate:	6.59%
Capital Breakdown:	
Labor:	$ 522
Contract Labor:	$ 3,724
Materials:	$ 3,340
Local Engineering:	$ 618
Burdens:	$ 735
Contingency:	$ 933
Transportation:	$ 75
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 9,947

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution and transmission line improvements are consistent with similar past projects.
  - 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**
  - The cost of the distribution portion of the project could escalate because costs are based on similar completed work for other projects of similar scope and size.
  - Additional private easements will need to be obtained to complete work as planned. Failure to obtain easements could result in transfer of work from distribution to transmission at similar funding level.
  - The potential for rock removal could increase costs, but should be covered by the contingency included for the Distribution Circuit work estimates.
  - Failure to approve this project could negatively impact the company’s ability to provide service to existing customers during planned or unplanned outage events.

Conclusions and Recommendation

It is recommended that the Investment Committee approve the Pleasure Ridge Distribution Substation Contingency Project for $9,947k to provide Distribution Substation Transformer Contingency Program (N1DT) benefits 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 Chief Financial Officer	Date	Paul W. Thompson Chairman, CEO and President	Date

Investment Proposal for Investment Committee Meeting on: February 23, 2017

Project Name: Stonewall Distribution Substation Transformer Contingency Project

Total Expenditures: $8,010k (includes $728k of contingency)

Project Number(s): Distribution Substations 148892, Distribution Lines 152865, Transmission Lines 134245

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: James Cline/Kevin Patterson

Executive Summary

KU Electric Distribution Operations (EDO) - Electrical Engineering and Planning (EEP) seeks funding authority for distribution substation, distribution circuit, and transmission line improvements in and near the KU Stonewall Substation. Stonewall Substation is located on Arrowhead Drive on the southwest side of Lexington, KY and serves approximately 5,494 commercial and residential customers. The purpose of this Investment Proposal is to request substation capacity improvements that includes the installation of a second 37.3 MVA transformer in the Stonewall Substation along with associated transmission and distribution circuit improvements in order to remove the Stonewall, Clays Mill, Parkers Mill 1, and Parkers Mill 2 transformers from the Company's Distribution Substation Transformer Contingency Program (N1DT) list. This project also improves the reliability of transmission service at Stonewall Substation with the installation of two transmission line breakers, reducing the time necessary to fault locate and perform switching in the event of a transmission line outage.

Approval is requested in the amount of $8,010k ($2,626k-2017, $5,384k-2018) to complete the Stonewall Distribution Substation Transformer Contingency project. This project is included in the 2017 EDO and Transmission Business Plan (BP) with a total funding level of $4,621k ($1,997k-2017, $2,624k-2018), and is scheduled to begin in March 2017 with completion in December 2018. The total cost of the project is more than the budgeted amount because:

1) the scope of the distribution circuit improvements increased slightly after the project details were reviewed,
2) the estimate for the unit cost of the distribution circuit improvements plus the unit cost of the transmission work in the Stonewall substation increased significantly, and
3) two 69kV line breakers and associated fiber communications were added to the project to enhance the transmission reliability.

The 2017 overrun of $629k will be reallocated from other EDO and Transmission projects, through the February RAC processes. The 2018 budget shortfall of $2,760k will be addressed in the 2018 BP.

Background

The Distribution Substation Transformer Contingency Program (N1DT) 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 could take up to 36 hours depending on the specific location.

The Stonewall, Clays Mill, Parkers Mill 1, and Parkers Mill 2 are all on the N1DT Contingency Program list.

	Customers	Capacity (MVA)	% Loaded Summer (Actual) (1)	% Loaded 2016 Summer (Forecast)
Stonewall	5,494	37.3	94% (estimated)	83%
Clays Mill	6,095	37.3	90% (estimated)	80%
Parkers Mill 1	2,971	22.4	83%	76%
Parkers Mill 2	4,090	22.4	84% (estimated)	79%

Note (1): The "% Loaded Summer (Actual)" amounts are "estimated" because switching was performed after the last temperature extreme summer peak to help manage the normal service transformer loads. The "estimated" amounts are a representation of the historical summer peak load levels with the present day switching.

The Stonewall Substation is adjacent to both the Clays Mill and Parkers Mill Substations, has multiple tie circuits, has available space for expansion, and provides the maximum benefit to multiple substations on the N1DT Contingency Program list. When the benefit to cost ratio of the proposed improvements are evaluated and compared to other N1DT projects, the Stonewall project ranks at the top of the N1DT Contingency Program list. The installation of a new 37.3 MVA substation transformer and associated improvements in the Stonewall Substation is proposed in order to remove the Stonewall, Clays Mill, Parkers Mill 1, and Parkers Mill 2 transformers from the Company's N1DT Contingency Program list.

- **Alternatives Considered**

1. Recommended Option: NPVRR: $9,197k
   The recommended option is to install a new standard 37.3 MVA transformer, steel package, transformer breaker, and two 69kV line breakers in the Stonewall Substation along with associated transmission and distribution line improvements to provide year round contingency for four area transformers while enhancing the reliability of transmission service to this station. Transmission Reliability recommends the installation of two 69kV line breakers because of the 5,494 existing customers (5,909 customers post project after load transfers) and 652 MW-Miles of transmission line exposure. The addition of line breakers reduces the time necessary to fault locate and perform switching in the event of a transmission line outage. This option is expected to remove the Stonewall, Clays Mill,

Parkers Mill 1, and Parkers Mill 2 transformers from the N1DT Contingency Program list. The estimated capital cost of this option is $8,010k.

2. Do Nothing Option: NPVRR: $11,057k
   This project is consistent with the objectives of the Company's Distribution Substation Transformer Contingency Program. The "do nothing" option was evaluated using standard corporate metrics to quantify the "Cost of Unserved Energy" benefit for providing contingency throughout the year for four areas substation transformers. Without adequate contingency capacity, the failure of any of the four transformers addressed by this project could result in an extended outage for some customers of up to 24 hours until the transformer can be replaced or a mobile transformer installed. Using a 5% annual probability of a failure of any of the four transformers, a "Cost of Unserved Energy" of $17.20/kwh, a reduction in outage duration of 24 hour outage with the loads going unserved at Stonewall (10.2 MW), Clays Mill (7.6 MW), Parkers Mill 1 (5.4 MW), and Parkers Mill 2 (3.7 MW), the "Cost of Unserved Energy" is approximately $555k annually. The estimated capital cost of this option is $0k.

3. Alternative 1: NPVRR: $9,660k
   This option considers the replacement of 2-22.4 MVA with 2-37.3 MVA transformers in the Parkers Mill Substation (plus associated distribution line improvements) plus the installation of transmission line breakers in the Stonewall Substation in order to accomplish similar benefits as the recommended option. This option is more expensive, adds less new transformer and circuit capacity, is a less effective system design, and results in less distribution reliability improvements than the recommended option and is not recommended. The estimated cost of this alternative is $8,423k.

Project Description

- **Project Scope**
  - Substation project #148892: estimated cost $4,375k ($2,062k-2017; $2,313k-2018).
    - Install a new 37.3 MVA, 69-12 kV transformer, 12kV breakers, transformer breaker, two 69kV line breakers, steel package, control house, and associated equipment in the Stonewall Substation; install the mobile transformer to serve the substation load during construction.
  - Distribution project #152865: estimated cost $1,315k ($314k-2017; $1,001k-2018).
    - Install approximately 7,900' of 795 AAC, 795 AAC spacer cable, and parallel 1000 Aluminum underground conductor as needed for two new distribution exit circuits and to relocate other substation exit circuits to the new substation transformer; perform other temporary work as necessary to accommodate the use of the mobile transformer during construction.
  - Transmission project #134245: estimated cost $2,320k ($250k-2017; $2,070k-2018).
    - Install poles and conductor as needed to connect the 69 kV transmission line to the new Stonewall Substation structure; replace transmission poles and install fiber communications as necessary between the Stonewall and Parkers Mill substation to satisfy transmission relaying requirements; perform other temporary work as

necessary to accommodate the use of the mobile transformer in the Stonewall substation during construction.

- A Network Integration Transmission Service (NITS) request was submitted to TranServ International for a new delivery point. Loads will primarily be transferred from the existing Stonewall transmission delivery point to the new Stonewall delivery point, although other loads (estimated net 3.3 MW summer) will be transferred to the Stonewall Substation from adjacent substations.

- **Project Timeline**
  - March, 2017: Open projects.
  - April-May, 2017: Perform substation and transmission engineering design related tasks; order major equipment.
  - June-August, 2017: Perform distribution engineering design related tasks for planned 2017 work; order materials.
  - September-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 $8,010k. The substation cost estimates are consistent with the "Conceptual Level 1" engineering design designation. The distribution and transmission line cost estimates are consistent with the "Preliminary" engineering design designation and are based on field experience from similar projects. There is an estimated 10% of contingency ($728k) 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)	2017	2018	2019	Post 2019	Total
1. Capital Investment Proposed	2,565	4,658	-	-	7,223
2. Cost of Removal Proposed	61	726	-	-	787
3. Total Capital and Removal Proposed (1+2)	2,626	5,384	-	-	8,010
4. Capital Investment 2017 BP	1,997	2,448	-	-	4,445
5. Cost of Removal 2017 BP	-	177	-	-	177
6. Total Capital and Removal 2017 BP (4+5)	1,997	2,625	-	-	4,622
7. Capital Investment variance to BP (4-1)	(568)	(2,210)	-	-	(2,778)
8. Cost of Removal variance to BP (5-2)	(61)	(549)	-	-	(610)
9. Total Capital and Removal variance to BP (6-3)	(629)	(2,759)	-	-	(3,388)

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 the 2017 Business Plan at the following levels: Substation project #148892 $3,231k ($1,566k-2017; $1,665k-2018); Distribution project #152865 $800k ($314k-2017; $486k-2018); Transmission project #134245 $591k ($117k-2017; $474k-2018). The 2017 and 2018 BP amounts are lower than the requested amount by $3,388k, some of which will be addressed through reallocations through RAC processes in 2017, while the remaining amount will be addressed through the 2018 BP process.

Financial Summary ($000s):

Discount Rate:	6.49%
Capital Breakdown:	
Labor:	$ 457
Contract Labor:	$ 2,693
Materials:	$ 2,896
Local Engineering:	$ 615
Burdens:	$ 498
Contingency:	$ 728
Transportation:	$ 123
Reimbursements:	($ 0)
Net Capital Expenditure:	$ 8,010

- **Assumptions**
  - The project unknowns will not exceed the estimated contingency amounts.
  - The estimated cost of the distribution and transmission line improvements are consistent with similar past projects.
  - The wood transmission poles between the Stonewall and Parkers Mill substations will need to be replaced in order to accommodate the fiber communications; the specific number will be determined after a detailed engineering design can be completed.
  - No significant unknown costs for transmission improvements will be associated with the addition of a new service point or the small amount of load transferred from other stations.

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

- **Risks**
  - The cost of the distribution portion of the project could escalate because costs are based on similar completed work for other projects of similar scope and size.
  - Failure to approve this project could negatively impact the company's ability to provide service to existing customers during planned or unplanned outage events.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the Stonewall Distribution Substation Expansion project for $8,010k to provide Distribution Substation Transformer Contingency Program (N1DT) benefits in Lexington, KY.

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

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

Project Name: West Hickman Substation Transformer Addition

Total Approved Expenditures: $4,362k (Approved on 03/31/2016)

Total Revised Expenditures: $5,218k, with an additional $856k requested

Project Number(s): Substation-150717, Distribution-150719, Transmission-150743

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tony Durbin

Reason for Revision

The original investment proposal (attached) for the West Hickman Substation Transformer Addition project was approved by the Investment Committee on March 31, 2016 for $4,362k; the substation portion was $3,150k.

Substation Engineering started to project higher than approved total costs for the substation portion of the project during the third quarter of 2017, primarily due to higher than estimated Company ($366k) and Contractor ($232k) labor costs and overhead burdens ($261k). During September 2017, Substation Engineering submitted an AIP seeking authorization to invest an additional $465k on the substation portion of the project, to enable continuation of construction. The purpose of this investment proposal is to seek authorization to increase the original project value by $856k, the total projected overrun based on Substation Engineering's final cost estimate for the overall project.

Category (Substation Only)	**Original Estimate Amount ($000s)**	**Current Actuals + Additional Estimated Cost ($000s)**	**Difference ($000s)**
Company Labor	$ 52	$ 418	$ 366
Contract Labor	$ 898	$ 1,130	$ 232
Materials	$ 1,427	$ 1,548	$ 121
Local Engineering	$ 359	$ 379	$ 20
Burdens	$ 108	$ 369	$ 261
Contingency	$ 286	$ 41	$ (245)
Transportation	$ 20	$ 55	$ 35
Miscellaneous	$ 0	$ 66	$ 66
Total	$ 3,150	$ 4,006	$ 856

<u>Company Labor</u>

Company labor costs for the project are estimated to run over primarily due to unplanned utilization of company resources for above grade site construction work. When the project design and plans were created in 2015, Substation Engineering originally planned to use contract labor, and budgeted $738k, for all site construction work. Since the original project estimate was completed, contract construction costs for substation projects have escalated more quickly than inflation, likely due to elevated construction activity ongoing regionally. Relatedly, as the West Hickman project progressed during 2017, Substation Engineering experienced higher than estimated site construction costs. Contracted costs ($700k) for below grade construction nearly consumed the total original budget allocation for above and below grade site construction. Substation Engineering ultimately assigned available Company labor to complete the planned above grade construction, and estimates that $385k will be required to finish the associated scope of work.

<u>Contract Labor</u>

Due to the high number of on-going substation projects, Substation Engineering outsourced design engineering for the West Hickman project to Burns and McDonnell. The original estimate for contract engineering on the project was $160k; however, Substation Engineering now estimates that final contract engineering costs on the project will total $435k. For this project, historical engineering costs were used to develop the engineering cost estimate, prior to development of detailed site plans and man-hour estimates. Once the final project cope was defined, and detailed man-hour requirements were calculated, the original project estimate and capital authority levels were not revised to reflect the higher contract engineering man-hour requirements. Substation Engineering should have addressed this variance to original budget earlier in the project execution.

Financial Summary ($000s):	**Approved**	**Revised**	**Explanation**
Discount Rate:	6.5%	6.32%	See explanations above
Capital Breakdown:			
Labor:	$ 103	$ 474	
Contract Labor:	$ 1,531	$ 1,828	
Materials:	$ 1,671	$ 1,817	
Local Engineering:	$ 462	$ 492	
Burdens:	$ 174	$ 441	
Contingency:	$ 397	$ 41	
Transportation:	$ 24	$ 59	
Miscellaneous:	$ 0	$ 66	
Reimbursements:	($ 0)	($ 0)	
Net Capital Expenditure:	$ 4,362	$ 5,218	
NPVRR:	$ 5,475	$ 6,231	

Financial Detail by Year - Capital ($000s)	**Pre-2017**	**2017**	**2018**	**Post 2018**	**Total**
1. Capital Investment Proposed	1,771	3,175	232	-	5,178
2. Cost of Removal Proposed	-	40	-	-	40
3. Total Capital and Removal Proposed (1+2)	1,771	3,215	232	-	5,218
4. Capital Investment 2017 BP	1,371	2,778	-	-	4,149
5. Cost of Removal 2017 BP	3	15	-	-	18
6. Total Capital and Removal 2017 BP (4+5)	1,374	2,793	-	-	4,167
7. Capital Investment variance to BP (4-1)	(400)	(397)	(232)	-	(1,029)
8. Cost of Removal variance to BP (5-2)	3	(25)	-	-	(22)
9. Total Capital and Removal variance to BP (6-3)	(397)	(422)	(232)	-	(1,051)

Financial Detail by Year - O&M ($000s)	**Pre-2017**	**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 2018 BP did not include this project, because it was originally anticipated to be completed in 2017. Transmission has some minor costs in 2018. The incremental funding in 2017 has been approved by the Corporate RAC process and the 2018 carry-over will be covered through the Corporate RAC process as well.

Conclusions and Recommendation
It is recommended that the Investment Committee approve the revised West Hickman Substation Transformer Addition project for $5,218k, an increase of $856k, to ensure adequate capacity for planned and future load additions at the West Hickman substation while removing the West Hickman and Ashland Pipe substations from the N1DT list and improving reliability on the West Hickman to Kentucky River 69kV transmission line.

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	

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 44

Responding Witness: John K. Wolfe

Q-44. Refer to the direct testimony of Lonnie E. Bellar, pages 52-53, wherein he discusses the DCC and the costs thereof.

a. Provide a breakdown of the $13M capital cost, including how the costs will be allocated between each company.

A-44.

a. The costs are split 42% LG&E and 58% KU:

Amount	Category
$ 297,000	Labor
$ 9,841,000	Contract Labor
$ 2,467,000	Materials
$ 64,000	Miscellaneous
$ 497,000	Burdens/Local Engineering
$ 167,000	Property Tax Capitalization
$ 13,333,000	**Total**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 45

Responding Witness: Lonnie E. Bellar

Q-45. Refer to the direct testimony of Lonnie E. Bellar, pages 53, wherein he discusses the planned "additional building on existing property at the South Service Center in Louisville."

a. Explain this proposed building, including the need for it to service customers. Any response should detail the cost justification for the investment, including detail of the expected savings resulting thereof.

b. Further, provide a breakdown of the estimated capital cost, including how the costs will be allocated between each company.

c. Are any capital costs or O&M expenses included in the forecasted period for recovery in this matter? If the response is in the affirmative, provide citation to all such costs.

A-45.

a. The proposed building on existing property at the South Service Center will provide a location that will place engineering in a consolidated location, bringing together groups that are currently located at various facilities because of space constraints. This co-location will centrally focus and improve operational support by addressing the current lack of adequate engineering work space. This proposed facility will resolve ongoing facility inadequacies by providing a protection and control engineering laboratory, needed storage for documentation and prints, and training and meeting facilities. As new employees are arriving, with limited (if any) industry experience and require a more regimented and progressive training program that incorporates new "virtual" technology, computer learning programs, hand-on training labs, this new facility will provide a sustainable training and laboratory operation. Construction of this facility facilitates execution of the company's capital and maintenance programs thus improving overall service to customers. Considering the justification outlined, no savings evaluations have been performed by the company.

b. All capital expenses are allocated to LG&E only. The following chart summarizes projected capital spend for the South Operations Engineering Center:

South Ops Engineering Center	**2019**	**2020**	**2021**	**Total By Category**
Outside Services	$ 2,320,800	$ 3,784,900	$ 3,111,300	**$ 9,217,000**
Labor – Straight Time	$ 341,036	$ 365,770	$ 407,788	**$ 1,114,594**
All Other Costs	$ 39,343	$ 60,970	$ 53,469	**$ 153,782**
Total by Year	**$ 2,701,179**	**$ 4,211,640**	**$ 3,572,557**	**$ 10,485,376**

c. As the building is not anticipated to be completed and operational prior to the end of the forecasted period, no O&M expenses were included in the forecasted period. Capital costs for the building are included in the forecasted period and are referenced in the following citations:

<u>Filing Requirements</u>
Schedule B-4.2 – Electric Operations, Page 6 of 8, Line 105
Schedule B-4.2 – Gas Operations, Page 2 of 4, Line 37

<u>PSC 1-17</u>
Attachment No. 1, Page 2 of 11, Line No. 105
Attachment No. 2, Page 1 of 7, Line No. 37

<u>PSC 1-18</u>
Attachment No. 1, Page 2 of 13, Line No. 105
Attachment No. 2, Page 1 of 8, Line No. 37

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 46

Responding Witness: John K. Wolfe

Q-46. Refer to the direct testimony of Lonnie E. Bellar, page 53, where he states that the DCC "facility is specifically designed to house 12-hour shift employees."

a. Explain what Mr. Bellar intended to indicate with this statement, including what design differences were necessary or implemented to accommodate "12-hour shift employees."

A-46.

a. The referenced DCC facility will house Distribution System Operators (DSO's) who work scheduled 12-hour shifts. DSO's also routinely work longer duration shifts when necessary to respond to abnormal distribution system operating conditions resulting from weather extremes.

Modern ergonomic workstations are being placed in the referenced DCC to provide for healthy working conditions for personnel who routinely work extended hours in a seated position.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 47

Responding Witness: Lonnie E. Bellar

Q-47. Refer to the direct testimony of Lonnie E. Bellar, page 55.

a. Provide the table presented on page 55 for the period June 30, 2018, to April 30, 2020.

A-47.

a. The following chart summarizes distribution capital expenditures by company from June 30, 2018, to April 30, 2020 (in millions).

	KU	**LG&E**	**Total**
Connect New Customer	$77	$58	$135
Enhance The Network			
Distribution Automation	*$22*	*$29*	*$51*
Circuit Hardening/Reliability	*$25*	*$15*	*$40*
Transformer Contingency	*$10*	*$15*	*$25*
Other	*$48*	*$25*	*$73*
Maintain The Network	$69	$88	$157
Repair The Network	$11	$16	$27
Miscellaneous	$4	$1	$5
Total	$266	$247	$513

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 48

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-48. Refer to the direct testimony of Lonnie E. Bellar, page 56, and Exhibit LEB-6 to Mr. Bellar's testimony.

a. Provide the same exhibit but with an additional column down the right hand side providing the amounts for June 30, 2018, to April 30, 2020.

b. For which of the projects listed have the Companies requested and received CPCNs?

c. For which of the projects listed do the Companies intend to request a CPCN?

A-48.

a. See attached.

b. With the exception of the Distribution Automation, which the Companies received a Certificate of Public Convenience and Necessity ("CPCN") in Case No. 2016-00371, the Companies have not applied for a CPCN for any of the projects for which cost recovery is sought in their applications. KRS 278.020(1) requires a utility to obtain a CPCN only for construction that is not "an ordinary extension of an existing system in the usual course of business." The projects included in the application are extensions of the Company's systems in the ordinary course of business and do not require a CPCN in compliance with 807 KAR 5:001 Section 15(3).

Except for the Distribution Automation discussed above, none of the projects listed in LEB-6 for which cost recovery is sought in the Companies' applications require a CPCN as each meets the regulatory definition of an extension in the ordinary course of business.

c. See the response to part b.

Smart Grid Investments
2019 BP
$000

Project	2019	2020	2021	2022	2023	Total	January 1, 2018 to October 31, 2019	June 30, 2018 to April 30, 2020
LG&E								
Distribution and Customer Services:								
Advanced Metering Systems (AMS) Opt In DSM	$ 250	$ 30	$ 32	$ 33	$ 34	$ 378	$ 312	$ 444
Distribution Automation	16,557	14,384	14,384	2,550	3,450	51,325	28,457	29,485
Electro-Mechanical Relay Replacement	3,000	2,500	2,500	2,500	2,500	13,000	2,673	3,336
Fuse Savings Pilot	350	350	490			1,190	302	452
Transmission:						-		
Control Houses	-	-	2,062	2,065	1,875	6,002	29	28
Fiber/Telecom	-	-	-	-	-	-	-	-
Relay Panels	3,959	2,542	2,178	2,171	2,873	13,722	6,801	6,294
RTU's	610	874	1,120	1,125	1,302	5,031	900	1,037
Switch - Auto	371	-	-	-	-	371	2,348	1,234
Switch - Motor Operated	156	507	-	-	-	663	391	524
Total LG&E	**$ 25,253**	**$ 21,187**	**$ 22,766**	**$ 10,443**	**$ 12,033**	**$ 91,682**	**$ 42,213**	**$ 42,834**
KU								
Distribution and Customer Services:								
Advanced Metering System (AMS) Opt In DSM	$ 250	$ 31	$ 32	$ 33	$ 34	$ 378	$ 554	$ 444
Distribution Automation	11,686	9,590	6,590	1,700	2,300	31,866	23,808	22,222
Electro-Mechanical Relay Replacement	3,000	2,500	2,500	2,500	2,500	13,000	2,776	3,637
Fuse Savings Pilot	150	150	210			510	130	195
KU SCADA Expansion	4,936	4,998	5,085	5,000	5,000	25,019	6,525	7,976
Transmission:						-		
Control Houses	3,687	5,242	4,464	3,994	3,520	20,906	5,845	6,815
Fiber/Telecom	-	345	349	-	-	694	-	-
Relay Panels	2,535	4,999	4,517	4,386	5,722	22,159	4,737	5,141
RTU's	2,573	2,843	2,133	2,119	2,359	12,027	3,804	5,111
Switch - Auto	953	683	-	-	-	1,636	4,013	2,755
Switch - Motor Operated	3,079	1,737	1,795	2,238	-	8,849	3,644	4,362
Total KU	**$ 32,850**	**$ 33,118**	**$ 27,675**	**$ 21,969**	**$ 21,434**	**$ 137,046**	**$ 55,837**	**$ 58,658**

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 49

Responding Witness: Christopher M. Garrett

Q-49. Contributions in Aid of Construction ("CIAC"): Provide the CIAC balances for each month in 2016, 2017, and 2018 YTD for each company. Explain how CIACs are reflected in the base year and forecasted cost of service.

A-49. See below for CIAC by month for 2016, 2017, and 2018 YTD. CIAC results in a reduction to capitalization and rate base as reflected in CWIP:

Month	CIAC	Month	CIAC
Jan-16	$ 1,060,075.56	Jun-17	757,389.33
Feb-16	681,403.17	Jul-17	948,984.44
Mar-16	334,686.88	Aug-17	841,223.01
Apr-16	1,577,734.12	Sep-17	1,728,327.69
May-16	1,063,885.32	Oct-17	886,493.92
Jun-16	906,205.07	Nov-17	1,845,145.16
Jul-16	865,141.35	Dec-17	1,297,123.71
Aug-16	1,381,296.73	Jan-18	1,557,199.64
Sep-16	287,585.69	Feb-18	1,674,227.67
Oct-16	730,546.58	Mar-18	1,270,801.23
Nov-16	834,957.85	Apr-18	1,139,082.35
Dec-16	930,739.49	May-18	1,046,113.08
Jan-17	601,401.59	Jun-18	793,108.54
Feb-17	925,092.20	Jul-18	338,934.34
Mar-17	889,268.23	Aug-18	1,295,272.75
Apr-17	2,139,735.11	Sep-18	943,560.86
May-17	754,863.19	Oct-18	935,593.00

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 50

Responding Witness: Christopher M. Garrett

Q-50. Do the Companies recover income taxes assessed on CIAC in base rates?

a. If the response is in the affirmative, provide the amount of taxable CIAC income reflected in the base and forecasted test years.

b. If the response is in the negative, how do the Companies recover income taxes assessed on CIAC?

A-50. Yes, the Company recovers income tax assessed on CIAC in base rates.

a. LG&E has $12,000,000 in both the base and forecasted test years for taxable CIAC income.

b. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 51

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-51. Reference the Bellar testimony at p. 52, wherein he discusses the ongoing construction of a new Distribution Control Center located adjacent to the existing Transmission Control Center. State whether the Companies have obtained a CPCN for the construction of this facility.

A-51. The Companies did not apply for a Certificate of Public Convenience and Necessity ("CPCN") for the Distribution Control Center. KRS 278.020(1) requires a utility to obtain a CPCN only for construction that is not "an ordinary extension of an existing system in the usual course of business."

Construction of the Distribution Control Center did not require a CPCN as it meets the regulatory definition of an extension in the ordinary course of business.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 52

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-52. Reference the Bellar testimony at p. 53, wherein he discusses the construction of two new facilities for distribution operations. State whether the Companies intend to file a petition with the Commission to obtain a CPCN for the construction of these facilities.

A-52. The South Service Center and the new facility in Elizabethtown are both in the planning stages. The Companies do not intend to apply for a Certificate of Public Convenience and Necessity ("CPCN") for either facility. KRS 278.020(1) requires a utility to obtain a CPCN only for construction that is not "an ordinary extension of an existing system in the usual course of business." The Public Service Commission's regulations define an extension in the ordinary course of business as an extension that does not create a wasteful duplication of plant, conflict with the existing certificates or service of other utilities operating in the same area or involve sufficient capital outlay to materially affect the existing financial condition of the utility or result in increased charges to the utility's customers. The cost of neither facility is expected to reach the threshold level to be considered a materially capital outlay. Moreover, the proposed facilities will either completely replace or augment an existing facility and will not be duplicating an existing facility.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 53

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-53. With regard to Exhibit LEB-6, "Smart Grid Investments" attached to the Bellar testimony, identify for which projects the Companies either have obtained, or plan to obtain a CPCN.

A-53. See the response to AG 1-48(b) and (c).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 54

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-54. Reference the Bellar testimony, p. 6, wherein he discusses the construction of a new power generation technical training center at Trimble Station, and of a new safety and technical training center at the LG&E East Operations Center.

a. Was any thought given to combining the two new facilities into one? If not, why not?

b. Will the Companies be filing an application for a CPCN for one or both of these facilities? If not, explain why not.

A-54.

a. The technical training center at Trimble County Station is located in a warehouse that was remodeled to suit the training needs of power plant personnel. The shops, work laboratories and tools are designed specifically to train individuals responsible for the maintenance and operations of a power plant although the classrooms are multi-purpose and can be used by various departments.

Likewise, the LG&E East Operations facilities is designed to train individuals responsible for electric and gas distribution operations. The training space for transformers, transformer banks, mock poles, plastic fusion and underground primary cable termination is unique to the work conducted by those individuals. Additionally, the location of the East Operation facility is located at one of the operations centers making it easier for those employees and others in the city and state to gather. Lastly, the Gas Department is a Louisville centered operation and it would not be practical to train the employees at a power plant in Trimble County.

b. The Companies did not request a CPCN for the technical training center located at the Trimble County generating station, which was completed in 2017, or the training center at LG&E's East Operations center that is expected to be completed in early 2019.

KRS 278.020(1) requires a utility to obtain a CPCN only for construction that is not "an ordinary extension of an existing system in the usual course of business." The Public Service Commission's regulations define an extension in the ordinary course of business as an extension that does not create a wasteful duplication of plant, conflict with the existing certificates or service of other utilities operating in the same area or involve sufficient capital outlay to materially affect the existing financial condition of the utility or result in increased charges to the utility's customers.

Both projects meet the regulatory definition of an extension in the ordinary course of business and does not require a CPCN. Neither conflicts with a CPCN or existing service of another utility. Neither is expected to duplicate existing facilities. The center at Trimble County involved the conversion of part of an existing warehouse at a cost of $1.7 million, was specifically designed for the training of generation employees and is solely equipped for that purpose. It is intended to improve system reliability through better trained generation plant personnel. It does not materially affect the Companies' financial condition. The East Operations Center will be used primarily for gas, electric, and transmission employees and is designed for outdoor instruction to reflect their work environment. Its expected capital cost at $2.6 million is not considered material.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 55

Responding Witness: Lonnie E. Bellar / Robert M. Conroy

Q-55. Refer to the direct testimony of Lonnie E. Bellar, pages 59-60, wherein he described the $91.2 million transmission line replacement/upgrade.

a. Provide the Company's analyses which evidences that the portion of the project wherein the Company "will replace segments of predominately 16-inch pipeline with 20-inch diameter pipeline, to achieve the uniform diameter," is a cost-beneficial investment.

b. Cite to the Company's application for a CPCN for this 13.2 mile transmission line upgrade.

c. Explain what portion of the $91.2 million price tag that the 13.2 mile transmission line replacement represents.

d. Explain the need for the 1.45 mile replacement of the pipeline connecting the Western Kentucky and Magnolia pipelines. Any response should explain the condition of the current pipeline, including why it is no longer adequate for service.

A-55.

a. While a formal analysis has not been completed, replacing the 13.2 miles is cost beneficial based on the following assessment:

- The replacements will enable each enhanced inline inspection tool to be run from one end of the pipeline to the other end in each of the WK A and WK B pipelines.

- Some multi-diameter enhanced inline inspection tools are not currently offered. As a result, the alternative to replacing the 13.2 miles of pipeline to achieve uniform diameter would be to complete a separate set of inline inspection tool runs for each change in pipeline diameter. To accomplish this, over 20 segments would be inspected separately in total between the WK A and WK B pipelines. The cost for an enhanced inline inspection assessment of a single-diameter pipeline is projected to be $2.5 million. Inline inspections are repeated every seven years.

- The WKA and WKB pipelines are equipped with above ground facilities at each end to launch and receive tools. Separate tools runs in the middle of the pipeline would require separating the pipelines and installing temporary tool launching and receiving equipment, then removing the temporary equipment after the tool to reconnect the pipelines. This would require isolating at least a portion of the pipeline each time.

- Replacing the 13.2 miles to get a uniform diameter for both lines facilitates coordination with tool vendors for inspecting the WKA and WKB pipelines as only one set of single-diameter tools would be needed to inspect each line versus coordination of multiple sets of single-diameter tool runs to accommodate each segment with different pipeline diameter~~s~~.

- 20-inch diameter pipeline makes up approximately 70% of the current pipeline for the WKA and WKB pipelines and greater than 50% for each pipeline. Replacements allowing conformity to 20-inch diameter pipe required the least amount of replacement to get to a single diameter. The 20-inch diameter is also adequate from a system planning perspective.

b. LG&E has not requested a CPCN for the transmission line upgrades. As explained in Mr. Bellar's testimony, this project involves the replacement of existing transmission line segments, and is in the ordinary course of business. The upgrades pertain to ten separate segments in two transmission lines and were described cumulatively.

c. Approximately $77.4 million has been included for the 13.2 miles. Of this amount, $9.6 million is included in the forecasted test period.

d. The pipeline is being replaced because its short length makes running enhanced ILI tools cost prohibitive for the length of pipe inspected.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 56

Responding Witness: Robert M. Conroy

Q-56. Refer to the direct testimony of Lonnie E. Bellar, page 60, wherein he describes the "Bullitt County pipeline project."

a. Is this the project for which LG&E received a CPCN in its last rate case, Case No. 2016-00371.

A-56.

a. Yes.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 57

Responding Witness: Lonnie E. Bellar

Q-57. Refer to the direct testimony of Lonnie E. Bellar, pages 61-61, wherein he describes the Nelson County Reinforcement Project. Mr. Bellar states that "the primary driver for this project is to extend an additional gas supply to the west side of the existing distribution system to accommodate additional growth. Mr. Bellar further states that the "existing system could support some modest commercial and residential growth."

a. Explain how much additional growth the existing system could accommodate.

b. Provide the studies or forecasts the Company depended on when assuming that growth in the short or medium term will outpace the capacity available on this portion of the system.

c. Are any costs associated with this project included in the Company's forecasted period in this matter? If so, cite to same.

A-57.

a. The west side of the Bardstown Gas System is fed from the medium pressure distribution system that extends from the current gas supplies coming primarily from (2) regulator stations located along highway 62 north of Hwy 245 and along Hwy 245 just to the south of CR-1615 (Glenwood Dr). With current supplies the existing west side of the system can support some additional small commercial and residential growth requiring lower loads and delivery pressures. However, due to the supplies being on the east side of the system, the west side of the system would be limited to support larger commercial or industrial requests requiring higher loads and potentially higher delivery pressures. The Nelson County Reinforcement Project will bring a high pressure distribution system to this corridor to support planned and future development in the area. The new pipeline will be sized to have pressure to support future residential, commercial and industrial growth on the west side of the system, in addition to providing an additional supply to the existing Bardstown distribution system.

b. As discussed in the response to part (a) of the question, system planning analysis has shown that the west side of the Bardstown system would be limited in supporting larger commercial or industrial load requests without the proposed pipeline reinforcement. Factors considered supporting the need for reinforcement to provide additional capacity include:

(1) The Company has been approached by an existing commercial gas customer with substantial load that will be moving to the western area of Nelson County.

(2) The Company has been approached in the past by another business with a commercial load request (capacity is currently available for this load). The business opted not to pay for the main extension at that time.

(3) In discussions with officials, Nelson County is focusing commercial and industrial development on the northwest area of the county as development in the industrial park has reached near capacity.

(4) The Kentucky Department of Transportation has presented two corridor options for a bypass that will provide a western route around Bardstown that will support future traffic flow and development. The proposed pipeline will terminate in the location of the proposed bypass near Hwy 245.

(5) Since 2015, the Company has received 28 commercial load requests from the Bardstown area and 12 have occurred along and to the north and west of Highways 62 and 150 in Bardstown. Commercial loads in this area will continue to diminish available capacity on the western side of Bardstown.

c. Yes, there is $31,619 of capital in the forecasted test period for the Nelson County Reinforcement Project.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 58

Responding Witness: Christopher M. Garrett

Q-58. Cash Working Capital. Provide a reconciliation of total operating expense reflected in the forecasted cost of service (Schedule C.1) to the total expenses lagged in the Companies' requested cash working capital allowances (Schedule B-5.2).

	Schedule C.1	Schedule B-5.2	Difference
	(A)	(B)	(C)
KU			
Total O&M Expenses	884,639,921	877,467,419	(7,172,503)
Total Depreciation and Amortization Expense	268,954,148	347,669,956	78,715,807
Total Taxes Other Than Income	43,682,224	45,617,136	1,934,912
Total Income Tax Expense	24,634,790	46,746,420	22,111,630
	1,221,911,084	1,317,500,930	95,589,847
LG&E - Electric			
Total O&M Expenses	627,292,494	635,106,277	7,813,783
Total Depreciation and Amortization Expense	155,800,380	228,887,386	73,087,006
Total Taxes Other Than Income	34,932,925	36,773,893	1,840,968
Total Income Tax Expense	24,281,656	43,595,949	19,314,292
	842,307,455	944,363,505	102,056,050
LG&E - Gas			
Total O&M Expenses	93,616,747	221,950,793	128,334,046
Total Depreciation and Amortization Expense	38,418,048	40,461,755	2,043,707
Total Taxes Other Than Income	11,768,640	12,584,590	815,950
Total Income Tax Expense	5,322,515	7,982,424	2,659,909
	149,125,951	282,979,562	133,853,612

A-58. See attached. The reconciliation includes Jurisdictional Adjustments (Schedule D-2) for Schedule C-1, which remove other rate mechanisms amounts not included in base rates. The jurisdictional cash working capital on Schedule B-5.2 removes only applicable other rate mechanism cash working capital amounts (e.g., ECR mechanism).

LG&E - Electric	Schedule C-1	Schedule B-5.2	Difference	Jurisdictional Adjustments Schedule D-2	Jurisdictional Pro Forma Adjustments to Forecasted Period Schedule D-2.1	Amortization of Regulatory Assets and Liabilities	Regulatory Debits	Total Reconciliation	Difference
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=SUM(D-G)	(I)=(H+C)
Total O&M Expenses	627,292,494	635,106,277	7,813,783	(12,605,094)	(1,054,764)	5,846,075		(7,813,783)	-
Total Depreciation and Amortization Expense	155,800,380	228,887,386	73,087,006	(65,694,674)		(5,846,075)	(1,546,257)	(73,087,006)	-
Total Taxes Other Than Income	34,932,925	36,773,893	1,840,968	(1,840,968)				(1,840,968)	-
Total Income Tax Expense	24,281,656	43,595,949	19,314,293	(18,883,701)	(1,798,041)			(20,681,742)	(1,367,450)

Correction to Total Income Tax Expense:	
Current: Federal (1)	8,524,549
Current: State (1)	2,192,074
Deferred: Federal and State (Including ITC) (1)	34,246,775
Total Income Tax Expense (Schedule C-2.1)	44,963,398
Total Income Tax Expense (Schedule B-5.2)	43,595,949
Difference	(1,367,450)

(1) Source file: Att_LGE_PSC_1-53_Sch_E_Electric.xlsx tabs "Current Tax F" and "Deferred Tax F".

LG&E - Gas	Schedule C-1	Schedule B-5.2	Difference	Jurisdictional Adjustments Schedule D-2	Jurisdictional Pro Forma Adjustments to Forecasted Period Schedule D-2.1	Amortization of Regulatory Assets and Liabilities	Regulatory Debits	Total Reconciliation	Difference
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)=SUM(D-G)	(I)=(H+C)
Total O&M Expenses	93,616,747	221,950,793	128,334,046	(128,316,101)	(279,501)	261,556		(128,334,046)	-
Total Depreciation and Amortization Expense	38,418,048	40,461,755	2,043,707	(1,782,151)		(261,556)	-	(2,043,707)	-
Total Taxes Other Than Income	11,768,640	12,584,590	815,950	(815,950)				(815,950)	-
Total Income Tax Expense	5,322,515	7,982,424	2,659,909	(2,460,857)	69,736			(2,391,121)	268,788

Correction to Total Income Tax Expense:	
Current: Federal (1)	2,455,183
Current: State (1)	(75,553)
Deferred: Federal and State (Including ITC) (1)	5,334,006
Total Income Tax Expense (Schedule C-2.1)	7,713,637
Total Income Tax Expense (Schedule B-5.2)	7,982,424
Difference	268,788

(1) Source file: Att_LGE_PSC_1-53_Sch_E_Gas.xlsx tabs "Current Tax F" and "Deferred Tax F".

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 59

Responding Witness: William Steven Seelye

Q-59. Schedule B-5.1 reports the inclusion of Fuel Stock, Gas Stored Underground, Materials and Supplies, and Prepayments under Other Working Capital Allowances on Schedule B-1. Have the test period operating expenses associated with these items been removed from cash working capital determined under the lead-lag method on Schedule B-5.2?

a. If the response is in the affirmative, explain why there are lagged expenses related to Fuel, Non-Fuel Commodities, Purchased Power, and Purchased Gas in cash working capital, as computed under the lead-lag method.

b. If the response is in the negative,

i. Explain why not removing the related expense from cash working capital under the lead-lag method does not lead to double counting in rate base?

ii. Provide the related expense reflected in each lagged item on Schedule B-5.2 for the forecast test year.

A-59. No.

a. Not applicable.

b.

i. Removing these expense items from the analysis of expense leads would increase cash working capital. For example, for coal expenditures the expense lead was determined as the difference between the time the coal is recorded in inventory and when the payment for the coal clears the Company's bank account. This difference results in positive expense lead days, which reduces cash working capital. Schedule B-5.1 includes inventory and prepayment amounts for which the Company incurs carrying costs until expensed in connection with providing service to customers. Therefore, there is no double counting in rate base because the cash working capital determined from the expense lead calculation in the lead/lag study and the prepayment or inventory items included in rate base measure two different and off-setting timing differences.

ii. Fuel and gas expenses are separately identified on Schedule B-5.2. Information is not readily available to determine the expense amounts attributable to Prepayments and Materials and Supplies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 60

Responding Witness: Christopher M. Garrett / William Steven Seelye

Q-60. Schedule B-5.2 reflects the inclusion of average balances related to Pension, OPEB, Regulatory Debits, and Regulatory Assets/Liabilities under Additional Cash Working Capital Items. Have the test period operating expenses associated with these items been removed from cash working capital under the lead-lag method?

a. If the response is in the affirmative, explain why there are lagged expenses related to Pension, OPEB, Regulatory Debits, Amortization of Regulatory Assets, and Amortization of Regulatory Liabilities in cash working capital, as computed under the lead-lag method.

b. If the response is in the negative:

i. Explain why not removing the related expense from cash working capital under the lead-lag method does not lead to double counting in rate base.

ii. Provide the related expense reflected in each lagged item on Schedule B-5.2 for the forecasted test year.

A-60. The items referenced received zero expense lead days which has the effect of removing the expenses from the analysis (as mentioned in Question No. 64). Also, see Page 1 for the base period and Page 4 for the forecasted test period of Schedule B-5.2.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 61

Responding Witness: Christopher M. Garrett

Q-61. The adjustment to remove ECR Cash Working Capital is based on the 1/8th principle, rather than the lead-lag method.

a. Provide a justification for the difference in methodology.

b. If the operating expenses proposed in base rates are synchronized with lagged expenses, would it be fair to say the ECR adjustment in cash working capital is unnecessary?

A-61.

a. The Commission approved the ES Forms setting forth the cash working capital methodology for the ECR mechanism which is the 1/8th formula.

b. No. Rate Base computations must correspond to Commission approved methods for base rates and other rate mechanisms.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 62

Responding Witness: Christopher M. Garrett

Q-62. Refer to the direct testimony of witness William Steven Seelye, page 102, wherein he states, "Mr. Garrett provided the balance sheet analyses used for the study of cash working capital based on amounts from the Companies' forecast." Provide a copy of the referenced balance sheet analyses.

A-62. The balance sheet analyses for LG&E refers to Schedule B-5.2, Pages 2-3 for the base period and Pages 5-6 for the forecasted test period. It is the schedule referenced in Question No. 60 and was provided as part of Tab 55 of the Filing Requirements.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 63

Responding Witness: Daniel K. Arbough / William Steven Seelye

Q-63. Refer to the direct testimony of witness William Steven Seelye, page 104, wherein he indicates the revenue lag includes a "bank lag, which is the period from when the customer payment is received to when the Companies have access to funds."

a. Provide bank documentation or other evidence to support the appropriateness of adding one day to the revenue lag.

b. Do the expense leads measure the bank lag associated with the period from when vendor payments are disbursed to when the Companies no longer have access to the funds?

A-63.

a. See attached.

b. The expense leads measure the time from when the service or expense was incurred to the time when cash payment for such service or expense cleared the Company's bank account (i.e., when the cash was no longer available to the Company). The bank lag is embedded in this time period.

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Effective November 12th, 2018

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Welcome to U.S. Bank and thank you for opening an account with us. This Agreement provides the general rules that apply to the account(s) you have with **U.S. Bank** described herein. Additional rules will be provided in:

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2. disclosures we give to you when you use additional products and services (for example our *Online and Mobile Financial Services Agreement and Fee Guide);*
3. periodic statements;
4. user guides;
5. *Consumer Privacy Pledge* brochure;
6. any appropriate means such as direct mail and notices on or with your statement, including any statements or notices delivered electronically; and
7. disclosures we give you about ATM and Debit Card Overdraft Coverage (applicable to certain consumer accounts, refer to the **Insufficient Funds and Overdrafts** section on page 6 for details).

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By providing a written or electronic signature on a signature card or other agreement or contract, opening, or continuing to hold an account with us, you agree to the most recent version of this Agreement, which is available to you at your local U.S. Bank branch, at www.usbank.com, or by calling U.S. Bank 24-Hour Banking at a number listed on the last page of this booklet.

This Agreement represents the sole and exclusive agreement between you and us regarding the subject matter described herein and supersedes all previous and contemporaneous oral agreements and understandings. If any terms of your signature card, resolution, or certificate of authority are inconsistent with the terms of this Agreement, the terms of this Agreement will control. Any other variations to this Agreement must be acknowledged by us in writing.

If you have any questions, please call us. Our most commonly used phone numbers are printed on the back of this booklet.

DEFINITIONS

The following definitions apply in this Agreement except to the extent any term is separately defined for purposes of a specific section. The words **"we," "our,"** and **"us"** mean **U.S. Bank National Association ("U.S. Bank").** We are a national bank. We are owned by **U.S. Bancorp.**

U.S. Bancorp and U.S. Bank own or control other companies, directly and indirectly. The members of this family of companies are our **"affiliates."**

The words **"you"** and **"your"** mean each account owner and anyone else with authority to deposit, withdraw, or exercise control over an account. If there is more than one owner, then these words mean each account owner separately, and all account owners jointly.

The term **"account"** means any savings, transaction (for example, checking, NOW Account), and time deposit (for example, certificate of deposit or CD) account or other type of account you have with us, wherever held or maintained.

An **"owner"** is one who has the power to deal with an account in his, her or its own name. An **"agent,"** in contrast, is one whose power to withdraw from an account comes from, or is on behalf of, the owners. Authorized signers, designated corporate officers, trustees, attorneys-in-fact, and convenience signers are examples of agents.

Entities such as corporations, limited liability companies, partnerships, estates, conservatorships, and trusts are not natural persons, and can only act through agents. In such cases, it is the **"entity"** that is the owner.

"Personal accounts" are consumer accounts in the names of natural persons (individuals). They are to be distinguished from **"non-personal accounts"** which are accounts in the name of businesses, partnerships, trusts and other entities.

Except where it is clearly inappropriate, words and phrases used in this document should be interpreted so the singular includes the plural and the plural includes the singular.

CELLULAR PHONE CONTACT POLICY

By providing us with a telephone number for a cellular phone or other wireless device, including a number that you later convert to a cellular number, you are expressly consenting to receiving communications—including but not limited to prerecorded or artificial voice message calls, text messages, and calls made by an automatic telephone dialing system—from us and our affiliates and agents at that number. This express consent applies to each such telephone number that you provide to us now or in the future and permits such calls for non-marketing purposes. Calls and messages may incur access fees from your cellular provider.

"you" includes, without limitation, your revocable trust, any partnership in which you are a general partner, any prior or successor entity by way of an entity conversion, and any other series of your series limited liability company (as applicable). In addition to this legal right, you give us and our affiliates the contractual right to apply, without demand or prior notice, all or part of the property (including money, certificates of deposit, securities and other investment property, financial assets, etc.) in your accounts, against any debt any one or more of you owe us or our affiliates. If your account is a joint account, you agree we may consider each joint owner to have an undivided interest in the entire account, so we may exercise our contractual right of setoff against the entire account. This includes, for example, debts that now exist and debts that you may incur later, your obligations under a guaranty, and also includes all fees you owe us or our affiliates. We will not be liable to you if enforcing our rights of setoff against your account(s) leaves insufficient funds to cover outstanding items or other obligations. You agree to hold us harmless from any claim arising as the result of our enforcement of our rights of setoff in, or enforcement of our rights of setoff against, your account(s).

Our contractual right of setoff does not apply:

1. to an account that is an IRA or other tax-deferred retirement account;
2. to a debt that is created by a consumer credit transaction under a credit card plan (but this does not affect our rights under any consensual security interest); or
3. if our records demonstrate to our satisfaction that the right of withdrawal that a depositor/debtor has with us only arises in a representative capacity (for example, only as an authorized signer, attorney-in-fact or a fiduciary) for someone else.

This right of setoff is in addition to any security interest that we or an affiliate of ours might have in your deposit account.

SECURITY INTEREST IN ACCOUNTS

You grant to us and our affiliates, a security interest in all your accounts with us, and all property in your accounts (including money, certificates of deposit, securities and other investment property, financial assets, etc.), to secure any amount you owe us or our divisions, department, and affiliates, now or in the future. This includes, for example, debts that now exist and debts that you may incur later, your obligations under a guaranty, and also includes all fees you owe us or our affiliates. For purposes of this section, "account" includes any account you have with us or any of our affiliates (including, without limitation, agency, custody, safekeeping, securities, investment, brokerage, and revocable trust accounts) and "you" includes, without limitation, your revocable trust, any partnership in which you are a general partner, any prior or successor entity by way of an entity conversion, and any other series of your series limited liability company (as applicable). In order to provide us and our affiliates with control over your account and all property in your account for purposes of perfecting the security interest granted above, you agree that we shall comply with any and all order, notices, requests and instructions originated by us or any of our affiliates directing disposition of the funds in your account without any further consent from you, even if such instructions are contrary to your instructions or demands or result in our dishonoring items which are presented for payment.

If your account is a joint account, you agree we may consider each joint owner to have an undivided interest in the entire account, so we may exercise our security interest against the entire account. We may enforce our security interest without demand or prior notice to you. You agree, for purposes of this security interest, that our affiliates may comply with any instructions we give them regarding your accounts held with them, without further consent. You also agree that we may comply with any instructions regarding your accounts that we receive from our affiliates pursuant to a security interest they have in your accounts with us. We will not be liable to you if enforcing our security interest against your account(s) leaves insufficient funds to cover outstanding items or other obligations.

You agree to hold us harmless from any claim arising as the result of our security interest in, or enforcement of our security interest against, your account(s).

SECURITY

It is your responsibility to protect the account numbers, including card numbers and electronic access devices (e.g., an ATM card, debit card, username and password or PIN) we provide to you for your account(s). Do not discuss, compare, or share information about your account number(s) with anyone unless you are willing to give him or her full use of your money. An account number can be used by thieves to encode your number on a false demand draft which looks like and functions like an authorized check.

If you furnish your access device and grant actual authority to make transfers to another person (a family member, coworker or employee, for example) who then exceeds that authority, you are liable for the transfers unless we have been notified that transfers by that person are no longer authorized.

Your account number can also be used to electronically remove money from your account. If you provide your account number in response to a telephone solicitation for the purpose of making a transfer (to purchase a service or merchandise, for example), payment can be made from your account even though you did not contact us directly and order the payment.

You must also take precaution in safeguarding your blank checks. Notify us at once if you believe your checks have been lost or stolen. As between you and us, if you are negligent in safeguarding your checks, you must bear the loss entirely yourself or share the loss with us (we may have to share some of the loss if we failed to use ordinary care and if we substantially contributed to the loss).

We reserve the right to place a hold on your account if we suspect irregular, fraudulent, unlawful or other unauthorized activity involved with your account. We may attempt to notify you of such a hold, but we are not required to provide notice prior to placing the hold. You agree that we may maintain such a hold until all claims against you or us to the funds held in your account, whether civil or criminal in nature, have been resolved fully in our sole satisfaction.

ARBITRATION

This section does not apply to any dispute in which the amount in controversy is within the jurisdictional limits of, and is filed in, a small claims court. This Arbitration Provision shall not apply to a party who is a covered borrower under the Military Lending Act. These arbitration provisions shall survive closure of your account or termination of all business with us. If any provision of this section is ruled invalid or unenforceable, this section shall be rendered null and void in its entirety.

Arbitration Rules: In the event of a dispute relating to or arising out of your account or this Agreement, you or we may elect to arbitrate the dispute. At your election, the arbitration shall be conducted by either JAMS or the American Arbitration Association ("AAA") (or, if neither of these arbitration organizations will serve, then a comparable substitute arbitration organization agreed upon by the parties or, if the parties cannot agree, chosen by a court of competent jurisdiction). If JAMS is selected, the arbitration will be handled according to its Streamlined Arbitration Rules unless the Claim is for $250,000.00 or more, in which case its Comprehensive Arbitration Rules shall apply. If the AAA is selected, the arbitration will be handled according to its Commercial Arbitration Rules. You may obtain rules and forms for JAMS by contacting JAMS at 1.800.352.5267 or www.jamsadr.com and for the AAA by contacting the AAA at 1.800.778.7879 or www.adr.org. Any arbitration hearing that you attend will take place in the federal judicial district in which you reside. Without regard to which arbitration body is selected to resolve the dispute, any disputes between you and us as to whether your claim falls within the scope of this arbitration clause shall be determined solely by the arbitrator, and not by any court.

Arbitration Process: Arbitration involves the review and resolution of the dispute by a neutral party. The arbitrator's decision will generally be final and binding. At your request, for claims made to consumer accounts, we will advance your filing and hearing fees for any claim you may file against us; the arbitrator will decide whether we or you will ultimately be responsible for those fees. Arbitration can only decide our or your dispute and cannot consolidate or join claims of other persons who may have similar claims. There will be no authority or right for any disputes to be arbitrated on a class action basis.

Effects of Arbitration: If either of us chooses arbitration, neither of us will have the right to litigate the dispute in court or have a jury trial. In addition, you will not have the right to participate as a representative or member of any class of claimants, or in any other form of representative capacity that seeks monetary or other relief beyond your individual circumstances, pertaining to any dispute subject to arbitration. There shall be no authority for any claims to be arbitrated on a class action or any other form of representative basis. Arbitration can only decide your or our claim, and you may not consolidate or join the claims of other persons who may have similar claims, including without limitation claims for public injunctive or other equitable relief as to our other customers or members of the general public. Any such monetary, injunctive, or other equitable relief shall be limited solely to your accounts, agreements, and transaction with us. Notwithstanding the foregoing, any question as to the validity and effect of this class action waiver shall be decided solely by a court of competent jurisdiction, and not by the arbitrator.

ATTORNEY'S FEES

Where used, "attorney's fees" includes our attorney's fees, court costs, collection costs, and all related costs and expenses. Notwithstanding any provision in this Agreement to the contrary, any provision for attorney's fees in this Agreement shall not be enforceable in any dispute governed by the laws of California or Oregon.

FUNDS AVAILABILITY: YOUR ABILITY TO WITHDRAW FUNDS – ALL ACCOUNTS

This funds availability policy applies to deposits into a checking or savings account made at a branch or ATM. This policy may not apply to deposits made remotely through a mobile or other electronic device.

Some sections of this disclosure apply to all accounts and all customers. There are special sections for New Accounts, Commercial Accounts, Wealth Management Accounts and Retail Consumer and Business Accounts. We will make that clear in the section headings.

Funds "availability" means your ability to withdraw funds from your account, whether those withdrawals are to be in cash, by check, automatic payment, or any other method we offer you for access to your account. If deposited funds are not "available" to you on a given day, you may not withdraw the funds in cash and we may not use the funds to pay items that you have written or honor other withdrawals you request. If we pay items that you have written or honor other withdrawals before funds are available to you, we may charge a fee for this. Please review the product pricing information brochure for information regarding overdraft fees associated with your accounts.

Please remember that even after the item has "cleared," we have made funds available to you, and you have withdrawn the funds, you are still responsible for items you deposit that are returned to us unpaid and for any other problems involving your deposit. See our **Returned Deposited and Cashed Items** section.

DETERMINING THE AVAILABILITY OF A DEPOSIT – ALL ACCOUNTS

The day funds become available is determined by counting business days from the day of your deposit. Every day is a business day except Saturdays, Sundays, and federal holidays. If you make a deposit in person before our "cutoff time" on a business day we are open, we will consider that day to be the day of your deposit for purposes of calculating when your funds will become available. However, if you make a deposit after the cutoff time, or on a day we are not open, we will consider that the deposit was made on the next business day we are open.

Our cutoff times vary from branch to branch. The earliest cutoff time at any of our branches is 2:00 p.m. (local time at the branch).

In addition, cutoff times may also vary depending on whether it is a deposit envelope ATM or a no deposit envelope ATM. If you make a deposit before 6:00 p.m. (local time, at the ATM location) for a deposit envelope ATM or before 8:00 p.m. (local time, at the ATM location) for a no deposit envelope ATM on a business day we are open, we will consider that day to be the day of your deposit. If you make a deposit at a deposit envelope ATM on or after 6:00 p.m. (local time), or on or after 8:00 p.m. (local time) for a no deposit envelope ATM or on a day we are not open, we will consider the deposit to be made on the next business day we are open.

Deposits you send by mail are considered deposited on the business day it arrives if it arrives by the cutoff time at the branch of deposit. In all cases, availability of any deposit assumes that a requested withdrawal will not overdraw the account.

IMMEDIATE AVAILABILITY – ALL ACCOUNTS

The following types of deposits will usually be available for withdrawal immediately under normal circumstances:

- Cash (if deposited in person to an employee of ours);
- Electronic direct deposits;
- Wire transfers; and
- The first $200.00 from the total of all other deposits made on any given day.

Cash and wire transfer deposits are subject to the **Special Rules for New Accounts** and the $200.00 availability is subject to the rule in the section titled **Longer Delays May Apply.**

LONGER DELAYS MAY APPLY

Government Checks, Cashier's Checks, and Other Types of Special Checks. If you make a deposit of one of the following items in person to one of our employees, our policy is to make the funds from those deposits available no later than the first business day after the day of deposit:

- State and local government checks that are payable to you;
- Cashier's, certified, and teller's checks that are payable to you; and
- Federal Reserve Checks, Federal Home Loan Checks, and U.S. Postal Money orders that are payable to you.

If you do not make your deposit in person to an employee of the bank (for example, if you mail us the deposit), funds from these deposits may be available no later than the second business day after the day of deposit. However, we may delay funds for a longer period of time, see section titled **Longer Delays May Apply – Safeguard Exceptions.**

Case-by-Case Delays. In some cases, we will not make all of the funds that you deposit available to you as provided above. Depending on the type of check that you deposit, funds may not be available until the second business day after the day of your deposit. The first $200.00 of your deposit, however, will be available no later than the first business day after the day of deposit, and usually immediately.

If we are not going to make all of the funds from your deposit available on the first business day, we will notify you at the time you make your deposit. We will also tell you when the funds will be available. If your deposit is not made directly to one of our employees (including a deposit made at an ATM) or if we decide to take this action after you have left the premises, we will mail you the notice by the day after we receive your deposit.

If you will need the funds from a deposit right away, you should ask us when the funds will be available.

Safeguard Exceptions. In addition, funds you deposit by check may be delayed for a longer period under the following circumstances:

- We believe a check you deposit will not be paid.
- You deposit checks totaling more than $5,000.00 on any one day.
- You redeposit a check that has been returned unpaid.
- You have overdrawn your account repeatedly in the last six months.
- There is an emergency, such as failure of computer or communications equipment.

We will notify you if we delay your ability to withdraw funds for any of these reasons, and we will tell you when the funds will be available. They will generally be available no later than the seventh business day after the day of your deposit.

RETAIL CONSUMER, BUSINESS AND COMMERCIAL ACCOUNTS

Our general availability policy for these accounts is to make funds available to you on the first business day after the day of deposit. We generally make some portion of a day's deposits available for withdrawal immediately. See the previous section for the types and amounts of deposits that are available immediately.

WEALTH MANAGEMENT ACCOUNTS

Our general availability policy for **Private Client Accounts** is to make funds you deposit available to you immediately. This immediate availability policy includes all deposits at any ATM. The section above titled **Longer Delays May Apply** also applies to your accounts. If we impose a delay as provided in that section, then the sections titled **Cashing Checks** and **Other Accounts** may also apply.

DEPOSITS AT AUTOMATED TELLER MACHINES – RETAIL CONSUMER, BUSINESS AND COMMERCIAL ACCOUNTS

Our Machines. If you make a deposit at an ATM identified as ours with the U.S. Bank name, your deposit will generally be available on the first business day after the day of deposit. However, in certain circumstances, and at U.S. Bank's discretion, the funds may not be available until the second business day after the day of deposit.

Other Machines. Generally, deposits at an ATM that is not identified as ours with the U.S. Bank name are not permitted. If we permit a deposit at an ATM that is not identified as ours with the U.S. Bank name, your deposit will not be available until the fifth business day after the day of deposit.

SPECIAL RULES FOR NEW ACCOUNTS – RETAIL CONSUMER AND BUSINESS ACCOUNTS

If you are a new customer, the following special rules will apply during the first 30 days your account is open.

Funds from electronic direct deposits and deposits of cash and wire transfers to your account will be available on the day we receive the deposit. The first $5,000.00 of a day's total deposits of cashier's, certified, teller's, traveler's, on-us checks (checks drawn on U.S. Bank), and federal, state and local government checks will be available on the first business day after the day of your deposit if the deposit meets certain conditions. For example, the checks must be payable to you (and you may have to use a special deposit slip). The excess amount over $5,000.00 will be available on the fifth business day after the day of your deposit. If your deposit of these checks (other than a U.S. Treasury check) is not made in person to one of our employees, the first $5,000.00 will not be available until the second business day after the day of your deposit.

Funds from all other check deposits will generally be available on the fifth business day after the day of your deposit. In certain instances, we may hold funds from other check deposits for longer than five business days. For example, if we receive a check that falls within the Safeguard Exception description above, we may delay funds for up to seven business days. If we do so, we will provide you with a hold notice at the time of deposit or when we learn that we will hold the funds from the deposit.

CASHING CHECKS

If we cash a check for you that is drawn on another bank, we may withhold the availability of a corresponding amount of funds that are already in your account. Those funds will be available at the time funds from the check we cashed would have been available if you had deposited it.

OTHER ACCOUNTS

If we accept for deposit a check that is drawn on another bank, we may make funds from the deposit available for withdrawal immediately but delay your availability to withdraw a corresponding amount of funds that you have on deposit in another account with us. The funds in the other account would then not be available for withdrawal until the day the deposited item would have been available, which will usually be the first business day after the day of deposit.

EFFECTIVE JANUARY 1, 2018

Business Accounts & Services and Transaction Banking Services

Disclosure and Agreement

MUFG UnionBank®

EFFECTIVE JANUARY 1, 2018

Business Accounts & Services

Disclosure and Agreement

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INTRODUCTION

Welcome to MUFG Union Bank, N.A. ("Union Bank"). Your account is backed by the reputation and resources of one of the largest banks on the West Coast, as well as by coverage of the Federal Deposit Insurance Corporation (FDIC) to permissible limits.

Most accounts may be accessed in person at a Union Bank® branch location, through Online Banking or Telephone Banking, or by using your ATM Card or Union Bank Debit Mastercard BusinessCard® ("Debit Card"). Not all accounts and services are offered at all times at every Union Bank branch for all account types.

This *Business Account & Services and Transaction Banking Services Disclosure and Agreement* also known as *All About Business Account & Services and Transaction Banking Services Disclosure and Agreement*, Bank Depositor Agreement (signature card), applicable fee schedule, other related documents we may provide you, and any amendments contain the terms of our agreement ("Account Agreement") with you for your account and any related services. This Account Agreement supersedes all previous agreements related to its subject matter including any oral or written communication. Except as otherwise stated, this Account Agreement does not alter or amend the terms or conditions of any other agreement you have with us.

Business Accounts

Business accounts are those accounts used for other than personal, family, or household purposes.

Customer Identification

To help the government fight money laundering and the funding of terrorism, federal law requires all financial institutions to obtain, verify, and record information that identifies each customer (individual(s) and/or entity(ies)) that opens an account, and to understand the anticipated activity of the account.

What this means: When you open an account, we will ask for information on the legal formation for your entity, such as name, address, and a tax identification number. We will ask your name, address, date of birth, and other information that will allow us to identify you and others authorized to use the account. We will ask to see a driver's license or other identifying documents. We may also ask for information about the ownership structure of your entity(ies) such as individuals with ownership and control over the entity.

We may further ask you for specific information regarding the nature of anticipated activity, the sources of your funds, the purposes of transactions, the anticipated frequency of such transactions, the relationship you have with persons to whom you send funds and the persons who send funds to you, the

English. We may decline to process any instruction written in a language other than English, whether issued by you or another person.

Facsimile Signatures

What is a facsimile signature: A facsimile signature is a procedure or mechanism that causes any check to be drawn on your account with a typed signature, facsimile signature, notation, mark, or other form of mechanical symbol, rather than your actual handwritten signature.

What we require for their use: You agree not to use facsimile signatures on checks unless you provide us with representative samples and we approve their use.

About paying facsimile Items: We may refuse to accept or may pay Items bearing facsimile signatures at our discretion.

What you're responsible for:

- You agree to assume full responsibility for any and all payments made by us when we rely on signatures that resemble the actual or facsimile signature(s) you provided (without regard to variation in color or size) in connection with your accounts or services.
- You authorize us to pay any check that appears to bear your authorized facsimile signature, including, but not limited to, Items created by you that display a computer-generated signature (regardless of whether you provided us with a representative sample) without further inquiry.
- You agree to indemnify, defend, and hold us harmless from any and all actions, claims, losses, damages, liabilities, costs, and expenses (including attorneys' fees) arising directly or indirectly from the misuse or the unlawful or unauthorized use or copying of facsimile signatures (whether affixed manually, by stamp, mechanically, electronically, or otherwise).

Funds Availability Policy

Your Ability to Withdraw Funds – Our policy is to make funds from your cash and check deposits available to you on the 1st Business Day after the Business Day we receive your deposit. Electronic direct deposits will be available on the day we receive the deposit. Once they are available, you can withdraw the funds in cash, and we will use the funds to pay checks that you have written, or other Items presented against your account. Please keep in mind, however, that after we make funds available to you and you have withdrawn the funds, you are still responsible for checks you deposit that are returned to us unpaid.

For determining the availability of your deposits, every day is a Business Day except Saturdays, Sundays, and federal holidays.

If you make a deposit before the close of business on a Business Day that we are open, or otherwise state as our Business Day, we will consider that day to be the day of your

deposit. If you make a deposit on a Business Day at one of our ATMs before 9:00 p.m. Pacific Time, we will consider that day to be the day of your deposit. However, if you make a deposit after this hour or on a day that is not considered a Business Day, we will consider that the deposit was made on the next Business Day we are open.

This *Funds Availability Policy* also does not apply to checks deposited other than at a staffed facility at the Bank, at a Union Bank ATM, night depository, lockbox, Express kiosk, or by mail addressed to Union Bank.

This *Funds Availability Policy* does not apply to checks drawn on banks located outside the United States, checks drawn in a foreign currency, or to checks deposited using Mobile Banking or Remote Deposit Service.

Longer Delays May Apply – In some cases, we will not make all of the funds that you deposit by check available to you on the 1st Business Day after the day of your deposit. Depending on the type of check that you deposit, funds may not be available until the 2nd Business Day after the day of your deposit. The first $200 of your deposit, however, will be available on the 1st Business Day after the day of your deposit.

If we are not going to make all of the funds from your deposit available on the 1st Business Day after the day of your deposit, we will notify you at the time you make your deposit. We will also tell you when the funds will be available. If your deposit is not made directly to one of our employees, or if we decide to take this action after you have left the premises, we will mail you the notice by the Business Day after we receive your deposit. If you will need the funds from a deposit right away, you should ask us when the funds will be available.

In addition, some or all of the funds you deposit by check may be delayed for a longer period under the following circumstances:

- We believe a check you deposit will not be paid.
- You deposit checks totaling more than $5,000 on any one day.
- You redeposit a check that has been returned unpaid.
- You have overdrawn your account repeatedly in the last 6 months.
- There is an emergency, such as failure of computer or communications equipment, that prevents us from making your deposit available to you under the timeframes set forth in our *Funds Availability Policy*.

We will notify you if we delay your ability to withdraw funds for any of these reasons, and we will tell you when the funds will be available. They will generally be available no later than the 7th Business Day after the Business Day of your deposit.

Special Rules for New Accounts – If you are a new customer, the following special rules will apply during the first 30 days your account is open.

Funds from electronic direct deposits to your account will be available on the day we receive the deposit. Funds from deposits of cash, wire transfers, and the first $5,000 of a day's total deposits of cashier's, certified and teller's checks, and federal, state and local government checks will be available on the 1st Business Day after the day of your deposit if the deposit meets certain conditions.

For example, the checks must be payable to you. The excess over $5,000 will be available on the 7th Business Day after the day of your deposit. If your deposit of these checks (other than a U.S. Treasury check) is not made in person to one of our employees, the first $5,000 will not be available until the 2nd Business Day after the day of your deposit. Funds from all other check deposits will be available on the 7th Business Day after the day of your deposit.

Remote Deposit Service

Generally, funds representing a deposit using Remote Deposit Services, will be available for withdrawal the Business Day after deposit if the remote check deposit is made prior to 8:00 p.m. Remote check deposits made on a non-Business Day will generally be available on the 1st Business Day after the Business Day of deposit. However, in some cases, we may delay funds availability up to the 2nd Business Day after the Business Day of your deposit. We will notify you (e.g., by email or text) if we delay availability of your deposit. Funds availability rules set forth in Federal Reserve Regulation CC do not apply to checks deposited using Remote Deposit Services. See the *Business Accounts & Services and Transaction Banking Services Disclosure and Agreement* for more information.

Mobile Check Deposits

Generally, funds representing a deposit using Mobile Check Deposit will be available to you on the 1st Business Day after the Business Day the deposit is received if the mobile check deposit is made prior to 9:00 p.m., Pacific Time. Mobile check deposits made on a non-Business Day will generally be available on the 1st Business Day after the Business Day the deposit is received. However, in some cases, we may delay funds availability up to the 7th Business Day after the Business Day the deposit is received. We will notify you (e.g., by email or text) if we delay availability of your deposit. Funds availability rules set forth in Federal Reserve Regulation CC do not apply to checks deposited using Mobile Check Deposit. See your *Online Banking Service Agreement* for more information.

We may, at our sole discretion, also hold funds you deposit for any reason necessary that we believe would limit your and/or our losses.

Each check deposited through a mobile device will count as one Combined Transaction.

Governing Law

To the extent this Account Agreement is subject to the laws of any state, it will be subject to the law of the state where your account is maintained, without regard to its conflict of laws principles. Your accounts and services also will be subject to applicable clearinghouse, Federal Reserve Bank, funds transfer system, image exchange, and correspondent bank rules ("Rules"). You agree that we do not have to notify you of a change in the Rules, except to the extent required by law. If there is any inconsistency between the terms of this Account Agreement and the Rules, the terms of this Account Agreement shall supersede the Rules, unless prohibited by the Rules.

Inactive Accounts and Unclaimed Property

Accounts become inactive when there has been no transaction or positive contact with us for a certain period of time, as follows:

- 12 consecutive months for transaction (demand deposit) accounts
- 18 consecutive months for savings accounts
- 24 months after the first maturity date or date of last customer contact for time deposit accounts

Positive contact will prevent an account from becoming inactive. Types of positive contact include:

- A deposit or withdrawal performed by you to or from the account. This does not include Bank-initiated transactions, such as service charges, interest payments, or automated deposits and withdrawals.
- Correspondence electronically or in writing concerning the account.
- A signed letter from you relating to the account's disposition.
- An indication from you of your interest in the account, such as contacting us to state your intention to maintain the account, or another record on file with us.

The inactive period begins on the date of the last transaction, last positive contact with us, or first maturity of a time deposit, whichever is latest. We may refuse to post any transactions to an inactive account unless we can confirm that you initiated the transaction. All inactive interest-earning accounts continue to earn interest, except for time deposit accounts that do not automatically renew. Service charges for inactive accounts are the same as those for active accounts. Charges are not reimbursed for inactive accounts that are later reclassified as active. Also, we may change the delivery of account statements for inactive accounts.

You may receive a written notice that your funds may be surrendered to a state government due to inactivity. The requirement to send a notice is based on the account balance

Effective February 2018

Deposit Agreement and Disclosures

Facts about corporate and commercial deposit account programs

Welcome to Bank of America Merrill Lynch, and thank you for opening an account with us. When you open a corporate deposit account with us, you agree to the terms and conditions discussed in this publication. Please read this publication carefully and keep it for your records. Throughout this publication, the words “you,” “your” and “yours” refer to the accountholder(s). “We,” “us” and “our” refer to Bank of America, National Association.

Bank of America Merrill Lynch

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Foreign currency checks

You may not write checks or give other withdrawal orders on your account, which order payment in foreign currency. If we receive such a check or order, we may refuse to accept or process it without any liability to you.

Foreign exchange transactions

If we assign a currency exchange rate to your foreign exchange transaction, such exchange rate will be determined by us based upon market conditions. We consider many factors in setting our exchange rates, including and without limitation: exchange rates charged by other parties, desired rates of return, market risk and credit risk. You acknowledge that exchange rates for retail and commercial transactions, and for transactions effected after regular business hours and on weekends, are different from the exchange rates for large inter-bank transactions effected during the business day, as reported in The Wall Street Journal or elsewhere. Exchange rates offered by other dealers, or shown at other sources (including online sources) may be different from our rates. We do not accept any liability if our rates are different from rates offered or reported by third parties, or offered by us at a different time, at a different location, for a different transaction amount, or involving a different payment media (bank-notes, checks, wire transfers, etc.).

Funds availability: When funds are available for withdrawal

We may negotiate a separate funds availability agreement with you. If we do not do so, then the following funds availability terms will apply to your account.

Your ability to withdraw funds. Our policy is to make funds from electronic direct deposits and incoming wire transfers available to you on the day we receive the deposit. Our general policy is to make funds from check deposits available to you no later than the first business day after the day we receive your deposit, when the check is drawn on a financial institution within the same local Federal Reserve district. Check deposits drawn on financial institutions in other districts may be made available on subsequent days. Once they are available, you can withdraw the funds in cash; and we will use the funds to pay checks that you have written. For determining the availability of your deposits, every day is a business day, except Saturdays, Sundays, and federal holidays.

If you make a deposit at a banking center before 2:00 p.m. local time, or such later time as may be posted at that banking center, on a business day that we are open, we consider that day to be the day of your

deposit. However, if you make a deposit in a banking center after such time, or on a day when we are not open, we consider that the deposit was made on the next business day we are open.

Other deadlines may apply for deposits made through other channels.

Government, official and other special types of checks. If you make a deposit in person to one of our employees, and meet the other conditions noted below, our policy is to make funds from the following types of deposits available no later than the first business day after the day of your deposit:

- U.S. Treasury checks that are payable to you
- State and local government checks that are payable to you and are deposited to an account in the same Federal Reserve District that issued the check
- Cashier's, certified and teller's checks that are payable to you

Other delays may apply. There are other situations that may affect funds availability. Depending on the type of check that you deposit, we may place a hold on certain checks and not make funds available until the fifth business day after the day of your deposit. In such a case, we generally notify you at the time you make your deposit. We also tell you when the funds will be available. If your deposit is not made directly to one of our employees, or if we decide to take this action after you have left the premises, we mail you the notice by the next business day after we receive your deposit.

If you need the funds from a deposit right away, you should ask us when the funds will be available.

In addition, we may delay the availability of funds you deposit by check for a longer period under the following circumstances:

- We believe a check you deposit will not be paid.
- You deposit checks totaling more than $5,000 on any one day.
- You redeposit a check that has been returned unpaid.
- You have overdrawn your account repeatedly in the last six months.
- There is an emergency, such as failure of communications or computer equipment.

We will notify you if we delay your ability to withdraw funds for any of these reasons, and we will tell you when the funds will be available. They will generally be available no later than the eleventh business day after the day of your deposit.

Cash withdrawal limitation. If we delay availability of your deposit, we place certain limitations on withdrawals in cash or by similar means. In general, $200 of a deposit is available for withdrawal in cash or by similar means no later than the first business day after the day of deposit. In addition, a total of $400 of other funds becoming available on a given day is available for withdrawal in cash or by similar means at or after 5:00 p.m. on that day. Any remaining funds will be available for withdrawal in cash or by similar means on the following business day.

Similar means include electronic payment, issuance of a cashier's or teller's check, certification of a check, or other irrevocable commitment to pay, such as a debit card transaction.

Holds on other funds. If we cash a check for you that is drawn on another financial institution, we may withhold the availability of a corresponding amount of funds that are already in your account. If we accept for deposit a check that is drawn on another financial institution, we may make funds from the deposit available for withdrawal immediately but delay your ability to withdraw a corresponding amount of funds that you have on deposit in another account with us. In either case, we make these funds available in accordance with our policy described above for the type of check that was cashed or deposited.

Special rules for new accounts. If you are a new customer, the following special rules may apply during the first 30 days after the account is open.

Funds from electronic direct deposits to your account are available on the day we receive the deposit. Funds from deposits of cash, wire transfers, and the first $5,000 of a day's total deposits of cashier's, certified, teller's, traveler's, and federal, state and local government checks are available no later than the first business day after the day of your deposit, if the deposit meets certain conditions. For example, the checks must be payable to you and deposited in person to one of our employees. The excess over $5,000 is available by the ninth business day after the day of your deposit. If your deposit of these checks (other than a U.S. Treasury check) is not made in person to one of our employees, the first $5,000 will not be available until the second business day after the day of your deposit. Funds from all other check deposits are generally available by the ninth business day after the day of your deposit. However, we may place longer holds on certain items for other reasons, such as large deposits. (See "Other delays may apply" in this section.)

Funds transfer services

A funds transfer is the process of carrying out a payment order that leads to paying a beneficiary. The payment order is the set of instructions you give or we receive regarding a funds transfer. The beneficiary is the person who receives the payment.

The following provisions apply to funds transfers you send or receive through us. If you have a specific agreement with us for these services, these provisions supplement but do not contradict that agreement. The terms "funds transfer," "payment order" and "beneficiary" are used here as they are defined in Article 4A of the Uniform Commercial Code – Funds Transfers, as adopted by the state whose law applies to the account for which the funds transfer service is provided.

We may charge fees for sending or receiving a funds transfer. These fees are described in the list of charges we may make available to you.

If you transfer funds in U.S. dollars to a non-U.S. dollar account, your payment may be converted into the local currency of the non-U.S. dollar account by an intermediary bank or the receiving bank (and we may receive compensation in connection with any such conversion.)

Fedwire. Fedwire is the electronic funds transfer system of the U.S. Federal Reserve Banks. When you send a payment order or receive a funds transfer, we or other banks involved in the funds transfer may use Fedwire. If any part of a funds transfer is carried out by Fedwire, your rights and obligations are governed by Regulation J of the U.S. Federal Reserve Board.

Sending funds transfers. You may subscribe to certain services we offer, or you may give us other instructions to pay money or have another bank pay money to a beneficiary.

This "Sending funds transfers" section applies to wire transfers and transfers we make between Bank of America accounts. It does not apply to Automated Clearing House ("ACH") system funds transfer services. You may only give us payment orders for ACH system funds transfers (where ACH services are available) if you have a separate agreement with us for these services. For blocking or filtering ACH receipts, see "Automated Clearing House (ACH) blocks and filters services" in this Agreement.

You are solely responsible for ensuring that payment instructions that are sent on your behalf are valid instructions authorized by your organization. While we may in some circumstances implement internal controls to monitor customer payments, including mechanisms that may evaluate the risk of possible fraudulent activity, such monitoring is done solely at our discretion and is not a component of the Security Procedures. You hereby acknowledge that we do not guarantee or ensure that such monitoring will be effective in preventing frauds against your accounts and agree that we may process payments verified by the Security Procedure regardless of the results of transaction monitoring. We will be considered to have acted in good faith and in compliance with the Security Procedures, regardless of the results of transaction monitoring.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 64

Responding Witness: William Steven Seelye

Q-64. Refer to Exhibit WSS-36 which presents the individual revenue lags and expense leads developed for each Company.

a. For each item with an expense lead of 0 (e.g., pension and OPEB expense, depreciation, amortization, and deferred taxes), clarify whether the intention is to reflect an exclusion from cash working capital or an actual expense lead of 0 days in the computation.

b. If the item with an expense lead of 0 should be reflected in the computation as shown in Schedule B-5.2, explain and provide supporting workpapers for the determination of 0 days.

A-64.

a. The intention of including an expense lead of 0 for the referenced items shown on Exhibit WSS-36 is to exclude these items from the calculation of cash working capital.

b. See the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 65

Responding Witness: Christopher M. Garrett

Q-65. What is the statutory payment date(s) for the KPSC Assessment?

A-65. The statutory payment date for the KPSC Assessment is July 31^{st} of the KPSC's upcoming fiscal year (July 1^{st} of the current year through June 30^{th} of the following year).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 66

Responding Witness: Christopher M. Garrett

Q-66. What are the statutory payment dates for sales tax, school tax, and franchise fees?

A-66. Per 103 KAR 25:131 - The sales tax for a large taxpayer, which is defined as averaging a monthly sales and use tax liability exceeding \$10,000, is required to be remitted by the 25th of each month.

Per Kentucky Revised Statute 160.615 - The school tax is due and payable monthly on or before the twentieth day of the next succeeding calendar month.

There are no statutory payment dates for franchise fees. The payment dates for franchise fees are agreed upon and specified by each municipality and LG&E when executing a franchise agreement.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 67

Responding Witness: William Steven Seelye

Q-67. For LG&E, explain why the billing lag for Electric (3.85) and Gas (3.95) are different. Are customers not issued combined bills?

A-67. Customers are issued combined bills if they receive both electric and gas service from the Company. However, the LG&E serves electric-only customers, gas-only customers, and combined electric and gas customers. The timing of when meters are read is dependent upon each particular customer's meter read date within its applicable window. All customers assigned to the same meter read window will be invoiced on the same date regardless of which day during the window their meter(s) was (were) read. Therefore, the analysis performed indicated a slight variance due to the timing of when the electric-only customer or gas-only customer meters were read compared to the combined electric and gas customer meters.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 68

Responding Witness: Daniel K. Arbough

D. Operating Expenses

Q-68. Refer to Schedule C-1, sponsored by Chris M. Garrett, in which "Electric Sales Revenue" is proposed to increase, but "Other Operating Revenues" is proposed to decrease.

a. Explain why it is reasonable to assume Other Operating Revenues will decrease in the forecasted test period.

A-68.

a. It is reasonable to assume that Other Operating Revenues will decrease in the forecasted period based on:

- The initial adjustment to the "Forecasted Adjustments At Current Rates" (Column 2 on Schedule C-1) is a reduction based on the lower historic trending average experienced in these accounts as explained on Schedule D-1 page 1 of 9.

- Furthermore, the reduction reflected in the "Proposed Increase" (Column 4) is primarily related to the proposed change in the late payment charge (see support at Exhibit WSS-14), the reduction in the proposed return check fee (see support at Exhibit WSS-18) and the reduction in the rate for excess facilities (see support at Exhibit WSS-16).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 69

Responding Witness: Christopher M. Garrett

Q-69. Refer to the direct testimony of Chris M. Garrett, pages 26-27, wherein he discusses the Companies' adjustments to operating revenues "that concerns OSS revenues related to the ECR calculation." Mr. Garret notes that the adjustments were performed "in a manner generally consistent with the methodology" used in the 2009, 2012, 2014 and 2016 base rate cases.

a. Explain what differences exist between previous methodologies used in the past base rate cases cited and the methodology used in these matters.

A-69. The 2009 and 2012 cases used historical test year data and the 2014 and 2016 cases used forecast period data.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 70

Responding Witness: Robert M. Conroy

Q-70. Refer to the direct testimony of Lonnie E. Bellar, page 20, wherein he describes the revenues the Companies derive from the sale of ash.

a. Explain why these revenues are reflected in the environmental surcharge mechanism and not through base rates.

A-70. The revenues related to beneficial reuse projects are included in the environmental surcharge mechanism via 2009 ECR Plan Project 25 as approved by the PSC in Case No. 2009-00198.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 71

Responding Witness: Daniel K. Arbough

Q-71. Refer to the direct testimony of Lonnie E. Bellar, pages 20-21, wherein he discusses refined coal facilities and the actual or anticipated revenues from same.

a. Provide citations to the test year where the revenues or anticipated revenues from the Ghent, Trimble County and Mill Creek stations are incorporated.

b. Explain whether these revenues or anticipated revenues are reflected or anticipated to be reflected in base rates or through the environmental surcharge.

A-71.

a. Refer to Schedule D-1 Electric, page 1 of 9, line 16. LG&E refined coal revenues for Trimble County and Mill Creek stations that were under contract at time of filing are reflected in account 456. See the response to KU Case No. 2018-00294, AG Question No. 71, for KU station anticipated revenues.

b. Refined coal revenues are anticipated to be reflected in base rates.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 72

Responding Witness: David S. Sinclair

Q-72. Reference the Bellar testimony, p. 21, wherein he discusses refined coal projects at Ghent, Trimble and Mill Creek.

a. Have the Companies been able to quantify any additional savings arising from reduced mercury and NOX emissions? If not, are the Companies aware of whether any other utilities' coal-fired generation stations utilizing similar refined coal systems have been able to achieve any such emission reductions?

b. Have the companies been able to achieve any additional savings through the Section 45 Production Tax Credit? Provide a quantification of any such savings, and indicate where in the application they can be found, and the accounting treatment afforded.

A-72.

a. No. The Companies have not performed any tests to quantify additional savings because performing such tests would be extremely difficult and imprecise in an environment with varying operating conditions (e.g., coal quality, ambient conditions, equipment performance, load levels, etc.). Prior to implementation, the Companies were able to perform tests demonstrating no adverse impacts on facility operations and their costs. The Companies are not aware of any other utilities that are quantifying additional savings.

b. The Companies are not achieving any additional savings through the tax credit.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

Case No. 2018-00295

Question No. 73

Responding Witness: Christopher M. Garrett

E. Operating Expenses

Q-73. Refer to the direct testimony of Chris M. Garrett, page 32, wherein he discusses advertising expenses.

a. Did the Companies remove all advertising expense, or only that advertising expense that did not produce a "material benefit" to ratepayers.

b. If the response to subpart a., above, indicates the latter, provide the advertising expense not removed for ratemaking purpose, including the rationale for each expense that it produces a "material benefit" for ratepayers. If necessary, break out these expenses and explanations by utility.

A-73.

a. The Companies removed advertising related to institutional and promotional expenses and only included safety and educational advertising.

b.

Advertising Category	Forecast Period	Benefit
Customer Newsletters & Direct Mailings	$ 262,600	The customer newsletter, which is included with the bill, and other direct mailings are the primary way in which LG&E reaches its customer to explain items related to their service including, but not limited to, safety, saving money, reducing energy, and changes to their service.
Customer Education	$1,040,000	LG&E believes it is important to ensure that customers understand how they can reduce energy and save money on their gas and electric bills. In the absence of many residential demand side

		management programs that helped customers understand the importance of energy management, LG&E is educating customers on various techniques they can do on their own to reduce the amount of energy they consume. The education process comes in a variety of forms to ensure we meet our customers in their varied ways they consume information.
Telephone Book Listings & Customer Information	$ 192,280	Telephone book listing and other directory services remain essential to ensuring our customers have the information they need to contact us.
Gas Safety	$ 234,000	Given the inherent dangers of natural gas, it is vital to ensure our customers understand how to avoid issues with their natural gas service and steps to take in the event they smell natural gas.
Other Safety & Education	$ 50,572	Safety is our number one priority and educating our customers, beginning at an early age, improves the chances that they will behave safely around natural gas and electricity.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 74

Responding Witness: Lonnie E. Bellar / Daniel K. Arbough / Christopher M. Garrett

Q-74. Refer to the direct testimony of Chris M. Garrett, page 37, wherein he states, "major outages typically occur on an eight-year cycle."

a. Provide evidence that outages occur on an eight-year cycle, rather than a shorter or longer schedule.

b. Provide the historical expenses for years 2013 through 2018 and forecasted expenses for years 2018 through 2024.

c. Explain why amortizing the regulatory deferrals over the same period as the "eight-year major outage cycle" is reasonable.

A-74.

a. See below for a list of the most recent turbine overhaul outage dates for units included in the forecasted test year. Typical time between outages is approximately 8 years, taking into consideration actual run time.

Unit	Major Outage Dates	
Trimble 1	2009	2017
Trimble 2	Began Commercial Operation in 2010	2018
Mill Creek 1	2004	2013
Mill Creek 2	2003	2012
Mill Creek 3	2004	2011
Mill Creek 4	2006	2014

b. See attached for 2013 through 2018 historical expenses and 2018 through 2022 forecasted expenses. Years 2023 and 2024 are outside of the eight-year cycle used to calculate the eight-year average outage expense included in the forecasted test year.

c. Outage expense included in base rates per the Company's last base rate case was set using an eight-year average of outage costs. Amortizing the deferred costs that are less than or exceed the eight-year average over an eight-year cycle is consistent with the ratemaking treatment for outage expense.

LG&E Outage - Not normalized Unit	FERC	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual YTD October
0311 - TRIMBLE COUNTY 1 - GENERATION	510	$ 111,518	$ 99,690	$ -	$ -	$ 657,584	$ -
	511	6,261	-	2,327	(987)	294,536	2,184
	512	945,856	4,464	2,192,311	86,660	4,191,657	74,958
	513	142,810	11,994	300,174	6,218	2,884,257	336,964
	514	-	-	-	-	6,324	-
0321 - TRIMBLE COUNTY 2 - GENERATION	510	-	46,072	-	66,543	-	-
	511	-	-	727	-	-	13,537
	512	533	531,445	131,801	299,329	406,179	832,993
	513	385	45,075	37,244	223,707	44,738	507,532
0401 - LGE GENERATION - COMMON	510	113,441	(213,381)	(90,334)	(7,152)	1,483	-
	513	-	-	-	-	-	-
0141 - CANE RUN 4 - GENERATION[1]	500	-	-	-	-	-	-
	510	-	-	-	-	-	-
	511	-	-	-	-	-	-
	512	120,277	468,671	-	-	-	-
	513	38,394	83,706	-	-	-	-
	514	-	-	-	-	-	-
0151 - CANE RUN 5 - GENERATION[1]	500	-	-	-	-	-	-
	511	-	-	-	-	-	-
	512	955,239	264,620	-	-	-	-
	513	217,596	58,038	-	-	-	-
	514	-	-	-	-	-	-
0161 - CANE RUN 6 - GENERATION[1]	510	-	-	-	-	-	-
	511	-	282	-	-	-	-
	512	319,077	589,175	707	-	-	-
	513	204,896	229,866	394	-	-	-
0211 - MILL CREEK 1 - GENERATION	510	278,017	-	426,475	-	205,869	-
	511	10,987	-	-	-	137	-
	512	2,538,798	90,155	1,969,498	190,030	2,399,835	595,185
	513	3,081,978	16,606	234,337	125,463	1,306,372	100,895
	514	-	-	-	-	-	1,181
0221 - MILL CREEK 2 - GENERATION	510	9,956	-	394,549	-	-	-
	511	-	-	-	-	-	-
	512	1,688	2,035,209	1,963,564	1,768,972	279,504	2,123,097
	513	2,834	235,191	622,480	1,347,379	97,951	2,272,268
	514	-	-	-	-	1,892	4,862
0231 - MILL CREEK 3 - GENERATION	510	338,409	283,456	-	112,896	-	-
	511	-	-	-	-	-	44,758
	512	3,252,673	34,968	327,318	2,942,769	192,702	2,459,145
	513	659,233	20,126	124,442	1,775,339	164,988	480,718
	514	124	-	-	-	-	-
0241 - MILL CREEK 4 - GENERATION	510	-	182,368	162,660	252,274	-	387,379
	511	-	-	-	12,335	8,270	24,210
	512	1,167,712	3,003,378	382,445	2,702,899	1,202,084	2,757,753
	513	124,182	3,756,372	123,461	574,125	163,038	1,518,116
	514	-	-	-	-	1,023	1,306

LG&E Outage - Not normalized Unit	FERC	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual YTD October
0212 - MILL CREEK-SO2 UNIT 1	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
0222 - MILL CREEK-SO2 UNIT 2	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
0232 - MILL CREEK-SO2 UNIT 3	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
0242 - MILL CREEK-SO2 UNIT 4	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
0172 - CANE RUN CC GT 2016	549	-	-	16,661	4,276	51,227	6,504
	551						-
	552	-	-	1,631	21,191	37,823	28,318
	553	-	-	43,139	219,940	431,030	169,479
	554	-	-	18,166	68,835	80,200	89,442
0431 - PADDYS RUN GT 12	553	27,835	-	-	-	-	-
	554	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	553	43,835	99,436	57,388	76,976	137,702	179,512
	554	409	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	553	-	-	-	-	720	4,662
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	553	-	-	-	-	-	20,662
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553	-	-	737	-	19,708	53,308
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	553	-	-	-	-	18,101	10,711
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	553	-	-	-	-	-	24,133
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	553	-	-	-	-	-	22,487
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	553	-	-	-	-	243,103	-
	554	-	-	15,726	-	-	17,672
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	551	-	-	-	-	-	-
	552	-	-	-	-	-	-
	553	16,232	44,418	12,786	4,560	(2,174)	-
	554	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	553	(24,548)	91,942	(43,973)	20,726	-	-
							-
Total		**$ 14,706,633**	**$ 12,113,341**	**$ 9,428,840**	**$ 12,895,303**	**$ 15,527,861**	**$ 15,165,930**

(1) Cane Run units 4,5 and 6 were retired in 2015.

LG&E Outage - Not normalized Unit	FERC	Base Year	Test Year	2019 Plan	2020 Plan	2021 Plan	2022 Plan
0311 - TRIMBLE COUNTY 1 - GENERATION	510	$ -	$ -	$ -	$ -	$ 187,500	$ -
	511	2,184	-	-	-	-	-
	512	18,976	2,699,137	2,699,138	218,400	3,121,007	219,225
	513	327,857	799,252	799,250	-	817,955	-
	514	-	-	-	-	-	-
0321 - TRIMBLE COUNTY 2 - GENERATION	510	-	39,187	-	39,187	-	-
	511	13,537	-	-	-	-	-
	512	782,958	192,178	151,856	204,222	74,962	922,571
	513	437,854	632,642	217,111	661,142	-	157,295
0401 - LGE GENERATION - COMMON	510	-	-	-	-	-	-
	513		-	-	-	-	-
0141 - CANE RUN 4 - GENERATION[1]	500	-	-	-	-	-	-
	510	-	-	-	-	-	-
	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
	513	-	-	-	-	-	-
	514	-	-	-	-	-	-
0151 - CANE RUN 5 - GENERATION[1]	500	-	-	-	-	-	-
	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
	513	-	-	-	-	-	-
	514	-	-	-	-	-	-
0161 - CANE RUN 6 - GENERATION[1]	510	-	-	-	-	-	-
	511	-	-	-	-	-	-
	512	-	-	-	-	-	-
	513	-	-	-	-	-	-
0211 - MILL CREEK 1 - GENERATION	510	-	-	200,000	-	450,000	-
	511	-	-	-	-	-	-
	512	594,837	975,000	1,730,001	450,000	1,820,001	515,000
	513	97,927	2,405,000	5,590,001	245,000	1,450,000	180,000
	514	1,181	-	-	-	-	-
0221 - MILL CREEK 2 - GENERATION	510	-	620,000	-	620,000	-	-
	511	-	-	-	-	-	-
	512	2,034,104	1,760,002	425,000	1,760,001	535,000	1,477,001
	513	2,526,632	2,160,000	300,000	2,160,000	225,000	2,200,001
	514	4,862	-	-	-	-	-
0231 - MILL CREEK 3 - GENERATION	510	-	1,177,500	1,177,500	-	-	-
	511	44,758	-	-	-	-	-
	512	2,474,261	1,730,000	2,055,000	449,999	1,755,001	525,000
	513	423,613	5,400,000	5,675,000	245,000	1,405,000	225,000
	514	-	-	-	-	-	-
0241 - MILL CREEK 4 - GENERATION	510	755,000	-	-	-	-	750,000
	511	-	-	-	-	-	-
	512	3,163,453	425,000	425,000	2,040,001	532,000	1,730,001
	513	2,650,327	220,000	220,000	1,635,000	222,000	5,389,999
	514	201	-	-	-	-	-

LG&E Outage - Not normalized Unit	FERC	Base Year	Test Year	2019 Plan	2020 Plan	2021 Plan	2022 Plan
0212 - MILL CREEK-SO2 UNIT 1	511	-	-	-	-	-	-
	512	-	-	-	-	-	145,000
0222 - MILL CREEK-SO2 UNIT 2	511	-	-	-	-	-	-
	512	-	-	-	-	-	150,001
0232 - MILL CREEK-SO2 UNIT 3	511	-	-	-	-	-	-
	512	-	-	-	-	150,001	100,000
0242 - MILL CREEK-SO2 UNIT 4	511	-	-	-	-	-	-
	512	-	-	-	-	100,001	150,001
0172 - CANE RUN CC GT 2016	549	-	-	-	-	-	-
	551		137,500	-	137,500	-	-
	552	6,781	-	-	-	-	-
	553	(130,216)	932,338	-	932,339	-	576,217
	554	278,430	1,263,947	293,138	970,808	277,686	396,921
0431 - PADDYS RUN GT 12	553	-	-	-	-	-	-
	554	-	-	-	-	-	-
0432 - PADDYS RUN GT 13	553	665,111	126,452	126,452	85,571	131,455	89,001
	554	-	-	-	-	-	-
0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE	553	4,715	6,099	12,479	13,639	45,249	62,649
0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE	553	20,670	8,999	3,199	8,999	11,899	105,279
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553	34,325	7,781	7,781	4,081	5,931	24,801
0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE	553	14,632	10,741	10,741	4,821	4,821	7,781
0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE	553	7,169	8,521	8,521	11,481	82,891	4,081
0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE	553	14,939	7,781	7,781	4,821	94,731	4,821
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	553	-	-	-	-	-	-
	554	17,672	-	-	-	-	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	551	-	-	-	-	-	-
	552	-	-	-	-	-	-
	553	27,900	9,595	300,154	9,595	9,739	9,885
	554	-	-	-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	553	-	19,398	9,627	9,771	347,905	10,067
Total		**$ 17,316,650**	**$ 23,774,050**	**$ 22,444,732**	**$ 12,921,378**	**$ 13,857,735**	**$ 16,127,598**

(1) Cane Run units 4,5 and 6 were retired in 2015.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 75

Responding Witness: Lonnie E. Bellar

Q-75. Refer to the direct testimony of Lonnie E. Bellar, page 19, wherein he states that "[i]n the calendar year 2018, the Companies have generated more than $11.4 million for the benefit of customers as a result of Off-System Sales ("OSS") of power produced by the Companies' generation facilities.

a. Explain if the $11.4 million amount is the amount of profit in total earned from OSS in 2018, or the amount allocated to customers.

A-75.

a. The $11.4 million amount is the amount that has been allocated to customers for calendar year 2018 through August. The monthly amounts are reported to the Commission as part of the OSS adjustment clause schedule – Page 1 of 3, line 3 as *Customer Share of OSS Margins*.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

Case No. 2018-00295

Question No. 76

Responding Witness: Elizabeth J. McFarland

Q-76. Refer to the direct testimony of Lonnie E. Bellar, page 30, wherein he states, "the Companies project operating expenses related to meter readers and field service contracts to significantly increase over current spending on these services." Further reference Schedule C-2.1 Page 4 of 12 and Page 10 of 12.

a. Other than the slight change in jurisdictional percentage, explain and provide support for the increase in METER READING EXPENSES located on line No. 106 on both referenced pages of Schedule C-2.1.

A-76.

a. Meter Reading and Field Service contracts will expire on May 31, 2019. Staffing issues signaled changing market conditions and likely increases in costs for these services. An RFI was issued in May 2018 for both meter reading and field service pricing and six responses were received. An RFP was issued in July 2018. RFP responses have been received and the Company is in the process of evaluating the bidders. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Attachment pages provided under confidential seal have been removed.

METER READING LABOR BREAKDOWN for LGE TERRITORY

Labor Classification	%xDirect labor $ *	Meter Reader			
Total Number of Meter Readers		50			
Estimated Annual Hrs/Meter Readers		2,024	101,200		
Base Pay Rate		18.00			
FICA and M/C	7.65%	1.38			
SUI	0.80%	0.14			
FUI	0.60%	0.11			
Workers Comp. Dollars	1.64%	0.30			
City Tax					
TOTAL REGULATORY		1.92			
Holiday pay	2.70%	0.49		7 days paid	
Vacation cost	4.00%	0.72			
TOTAL BENEFITS		1.21			
Group Insurance Cost	6.60%	1.19			
Bonus Dollars	20.00%	3.60		Yearly retention bonus and accuracy bonus, burdened	
Umbrella Ins.	1.00%	0.18			
General Liability Ins.	0.50%	0.09			
Small tools	4.65%	0.84			
Vehicles		6.67			
Depreciation bldg.(Rent)		0.00			
Administrative Cost: (including some penalties)	18.60%	3.35			
Local - Payroll		0.00			
Corp Overheads		0.00			
Field Supervision/ Superintendent/ Management	21.80%	3.92		Burdened	
Lodging/Per Diem	0.90%	0.16			
Safety training	3.70%	0.67			
Others (PLEASE LIST ANY OTHER)					
Overtime compensation	4.95%	0.89		Burdened	
Communications	1.50%	0.27			
Drug test	0.90%	0.16			
TOTAL OVERHEADS		21.99			
Total Burden Cost per hour		43.12			
Total Burden Cost x Annual Hrs (Cell C6)		87,277.10			
Total Annual Burden Cost					4,363,854.84
Annual Meters Read					8,252,722
Cost per Meter Read Before Profit					0.529
Profit (%)					12.7%
Cost Per Meter Read				$	0.596

**** Note if cost item cannot be calculated as % of direct labor, note how cost calculated***

METER READING LABOR BREAKDOWN for LGE TERRITORY

Labor Classification	%xDirect labor $	**Meter Reader**	
Total Number of Meter Readers		55	
Estimated Annual Hrs/Meter Readers		1,992	
Base Pay Rate		13.00	
FICA and M/C	7.65%	0.99	
SUI	5.10%	0.66	
FUI	0.60%	0.08	
Workers Comp. Dollars	6.43%	0.84	
City Tax			
TOTAL REGULATORY		2.57	
Holiday cost per employee per year		747.36	
Vacation cost per employee per year		622.80	
TOTAL BENEFITS per employee hour		0.69	
Backgrounding, uniform & Other per employee per hour		0.94	
Bonus Dollars per employee hour		1.00	
General Liability & Umbrella Ins per employee hour		0.34	
Small tools per employee hour		0.81	
Vehicles per employee hour		7.83	
Administrative Cost:			
Corp Overheads	22.50%	2.93	
Field Supervision/Superintendent per employee hour		9.67	
Lodging/Per Diem per employee hour		0.04	
Safety training per employee hour		0.52	
Others (PLEASE LIST ANY OTHER)- Mobilization/Demobilization per employee hour		0.23	
TOTAL OVERHEADS		24.29	
Total Burden Cost per hour		27.55	
Total Burden Cost x Annual Hrs (Cell C6)		54,874.08	
Total Annual Burden Cost			54,874.08
Total Direct Labor Pay			25,896.00
Annual Meters Read			8,005,140
Cost per Meter Read Before Profit			0.555
Profit (%)	10.00%		0.055
Cost Per Meter Read			0.610

**** Note if cost item cannot be calculated as % of direct labor, note how cost calculated***

METER READING LABOR BREAKDOWN for LGE TERRITORY

Labor Classification	%xDirect labor $ *	Meter Reader		
Total Number of Meter Readers		60		
Estimated Annual Hrs/Meter Readers		2,016		
Base Pay Rate		14.50		
FICA and M/C	7.65%	1.11		
SUI	2.70%	0.39		
FUI	0.60%	0.09		
Workers Comp. Dollars	4.70%	0.68		
City Tax	0.00%	0.00		
TOTAL REGULATORY		2.27		
Holiday pay	4.37%	0.63		
Vacation cost	3.97%	0.58		
TOTAL BENEFITS		1.21		
Group Insurance Cost	12.00%	1.74		
Bonus Dollars	0.00%	0.00		
Umbrella Ins.	1.93%	0.28		
General Liability Ins.	2.50%	0.36		
Small tools	0.32%	0.05		
Vehicles				
Depreciation bldg.(Rent)		0.00		
Administrative Cost:				
Local - Payroll	9.40%	1.36		
Corp Overheads	24.49%	3.55		
Field Supervision/ Superintendent	36.49%	5.29		
Lodging/Per Diem		0.00		
Safety training	0.81%	0.12		
Others: Overtime	4.96%	0.72		
Others: Uniforms, Azuga, GPS	1.63%	0.24		
TOTAL OVERHEADS		13.71		
Total Burden Cost per hour		31.68		
Total Burden Cost x Annual Hrs (Cell C6)		63,875.82	3,832,549.06	
Total Annual Burden Cost				3,896,424.87
Annual Meters Read				8,252,722
Cost per Meter Read Before Profit				0.47
Profit (%)				20%
Cost Per Meter Read				0.57

**** Note if cost item cannot be calculated as % of direct labor, note how cost calculated***

Item No.	Item Name	Quantity	UOM	%age to Wage Rate	Straight Pay Hourly Rate	Overtime Hourly Rate	Total Standard Pay Rate	Total OT Pay Rate
1	HourlyWage Rate	1	Each		14.000	21.000		
Reg1	Fica	1	Each	0.077	1.071	1.607		
Reg2	Sui	1	Each	0.051	0.714	1.071		
Reg3	Fui	1	Each	0.006	0.084	0.126		
Reg4	WC	1	Each	0.064	0.900	0.900		
Reg 5	City Tax	1	Each	0.000	0.000	0.000		
TotalReg	**TOTAL REGULATORY**	1	Each	0.198	2.769	3.704	2.769	3.704
Ben1	Holiday	1	Each	0.023	0.320	0.320		
Ben2	Vacation	1	Each	0.019	0.270	0.270		
Ben3	Group Insurance	1	Each	0.000	0.000	0.000		
Ben4	401K	1	Each	0.000	0.000	0.000		
Ben 5	Bonus	1	Each	0.071	1.000	1.000		
Ben 6	Msc.	1	Each	0.970	13.581	16.101		
TotalBen	**TOTAL BENEFITS**	1	Each	1.084	15.171	17.691	15.171	17.691
Over1	Liability Insurance	1	Each	0.000				
Over2	Admin	1	Each	0.000				
Over 3	Equip & Tools	1	Each	0.000				
Over 4	Other	1	Each	0.000				
TotalOv	**TOTAL OVERHEAD**	1	Each	0.155	2.170	3.255	2.170	3.255
P1	Profit	1	Each	0.714	10.000	10.000	10.000	10.000
TB1	**Total Burden**	1	Each	2.151	30.110	34.650	30.110	34.650
Billable Rate	**Billable Rate**	1	Each				44.110	55.650

Item No.	Item Name	Quantity	UOM	%age to Wage Rate	Straight Pay Hourly Rate	Overtime Hourly Rate	Total Standard Pay Rate	Total OT Pay Rate
1	HourlyWage Rate	1	Each		19.000	28.500		
Reg1	Fica	1	Each	0.076	1.450	2.180		
Reg2	Sui	1	Each	0.009	0.174	0.000		
Reg3	Fui	1	Each	0.002	0.040	0.000		
Reg4	WC	1	Each	0.025	0.475	0.660		
Reg 5	City Tax	1	Each	0.000	0.000	0.000		
TotalReg	**TOTAL REGULATORY**	1	Each	0.113	2.139	2.840	2.139	2.840
Ben1	Holiday	1	Each	0.080	1.520	0.000		
Ben2	Vacation	1	Each	0.000	0.000	0.000		
Ben3	Group Insurance	1	Each	0.080	1.520	0.000		
Ben4	401K	1	Each	0.000	0.000	0.000		
Ben 5	Bonus	1	Each	0.000	0.000	0.000		
Ben 6	Msc.	1	Each	0.000	0.000	0.000		
TotalBen	**TOTAL BENEFITS**	1	Each	0.160	3.040	0.000	3.040	0.000
Over1	Liability Insurance	1	Each	0.010	0.190	0.285		
Over2	Admin	1	Each	0.080	1.520	0.000		
Over 3	Equip & Tools	1	Each	0.045	0.860	0.000		
Over 4	Other	1	Each	0.100	1.900	0.000		
TotalOv	**TOTAL OVERHEAD**	1	Each	0.155	2.945	4.418	2.945	4.418
P1	Profit	1	Each	0.080	1.520	2.280	1.520	2.280
TB1	**Total Burden**	1	Each	0.508	9.644	9.538	9.644	9.538
Billable Rate	**Billable Rate**	1	Each				28.644	38.038

Item No.	Item Name	Quantity	UOM	%age to Wage Rate	Straight Pay Hourly Rate	Overtime Hourly Rate	Total Standard Pay Rate	Total OT Pay Rate
1	HourlyWage Rate	1	Each		16.500	24.750		
Reg1	Fica	1	Each	7.65%	1.262	1.890		
Reg2	Sui	1	Each	0.60%	0.099	0.150		
Reg3	Fui	1	Each	2.70%	0.446	0.670		
Reg4	WC	1	Each	4.70%	0.776	1.160		
Reg5	City Tax	1	Each	0.00%	-	-		
Total Reg	**TOTAL REGULATORY**	1	Each	15.65%	2.583	3.870		
Ben 1	Holiday	1	Each	4.37%	0.721	-		
Ben 2	Vacation	1	Each	3.97%	0.655	-		
Ben 3	Group Insurance	1	Each	12.00%	1.980	-		
Ben 4	401K	1	Each	3.00%	0.495	0.740		
Ben 5	Bonus	1	Each	0.00%	-	-		
Ben 6	Msc.	1	Each	0.00%	-	-		
TotalBen	**TOTAL BENEFITS**	1	Each	23.34%	3.851	0.740		
Over1	Liability Insurance	1	Each	2.50%	0.413	0.620		
Over2	Admin	1	Each	42.93%	7.083	-		
Over3	Equip & Tools	1	Each	5.00%	0.825	-		
Over4	Other	1	Each	70.10%	11.566	-		
TotalOver	**TOTAL OVERHEAD**	1	Each	120.53%	19.887	0.620		
P1	Profit	1	Each	20.00%	3.300	4.950		
TB1	**Total Burden**	1	Each	179.52%	29.621	5.230		
Billable Rate	Billable Rate	1	Each				46.121	34.930

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 77

Responding Witness: Daniel K. Arbough / Lonnie E. Bellar

Q-77. Vegetation Management: Provide the following information related to Vegetation Management non-storm related O&M and capital expenditures. Provide this information separately for Transmission and Distribution.

a. The accounting policy for each company that determines what Vegetation Management expenditures are charged to Capital and what are charged to O&M.

b. For O&M Expenses:

i. The total dollars budgeted by company, by year, for 2013–2017 and 2018 YTD.

ii. The total dollars spent by company, by year, for 2013–2017 and 2018 YTD.

iii. Please explain over/under variances from budget by company, by year, by functional area (Transmission, Distribution).

c. For Capital:

i. The total dollars budgeted by company, by year, for 2013–2017 and 2018 YTD.

ii. The total dollars spent by company, by year, for 2013–2017 and 2018 YTD.

iii. Please explain over/under variances by company, by year, by functional area (Transmission, Distribution).

d. Explain the Companies' methodologies and policies regarding what level of detail each Company plans and budgets for Vegetation Management.

A-77.

a. LG&E and KU do not have a policy specific to Vegetation Management. The Companies rely on Accounting Policy 650 – Capital – Additions and Retirements Policy and Procedures to determine what Vegetation Management expenditures are charged to Capital and what are charged to O&M.

   Accounting Policy 650 – Capital – Additions and Retirements Policy and Procedures was provided as an attachment to the response to PSC 1-8.

b. See attached for O&M costs for actual and budget for 2013-2017 and 2018 through October, with variance explanations.

c. See attached for Transmission capital costs for actual and budget for 2013-2017 and 2018 through October, with variance explanations. Capital totals for Distribution tree trimming are not readily available as associated costs are charged against numerous reliability improvement or system enhancement capital projects.

d. The Companies plan and budget Distribution Vegetation Management work at the Company level consistent with the Louisville Gas and Electric Company and Kentucky Utilities Company Distribution Vegetation Management Plan filed with the Kentucky Public Service Commission on December 19, 2007. The Companies plan and budget Transmission Vegetation Management work using the expected number of crews and equipment needed to support the vegetation management program. The Company also uses established rates from their long-term vegetation management contractors for planning and budgeting.

Vegetation Management O&M Expenses
Actual vs Budget 2013-2018
(000's)

Distribution

	2013				2014				2015				2016				2017				YTD 10/31/2018			
Description	**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**	
LGE	$ 6,733,617	$ 7,126,214	$ 392,597	a	$ 8,373,773	$ 6,792,581	$ (1,581,192)	b	$ 9,517,473	$ 7,703,724	$ (1,813,749)	b	$ 8,653,865	$ 9,564,712	$ 910,847	b	$ 7,841,253	$ 9,287,000	$ 1,445,747	b	$ 6,633,621	$ 6,954,770	$ 321,149	b

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.

Transmission

	2013				2014				2015				2016				2017				YTD 10/31/2018			
Description	**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**		**Actual**	**Budget**	**Variance (Over)/Under**	
LGE	$ 1,058,716	$ 1,049,082	$ (9,634)		$ 684,828	$ 1,949,582	$ 1,264,754	c	$ 793,880	$ 1,971,770	$ 1,177,890	c	$ 1,773,848	$ 1,138,429	$ (635,419)	c	$ 2,374,306	$ 2,292,155	$ (82,151)		$ 2,235,047	$ 3,300,648	$ 1,065,601	d

c Actual vegetation maintenace expenses varied by company and from budget based upon aerial inspections and just in time trimming needs.

d Lower than budget through the first 10 months of 2018 due to the timing for 345kV clearing, cycle clearing, and hazard tree removal work.

Vegetation Management Capital Expenses - Transmission
Actual vs Budget 2013-2018
(000's)

Description	2013 Actual	2013 Budget	2013 Variance (Over)/Under	2014 Actual	2014 Budget	2014 Variance (Over)/Under	2015 Actual	2015 Budget	2015 Variance (Over)/Under	2016 Actual	2016 Budget	2016 Variance (Over)/Under	2017 Actual	2017 Budget	2017 Variance (Over)/Under	YTD 10/31/2018 Actual	YTD 10/31/2018 Budget	YTD 10/31/2018 Variance (Over)/Under
LGE	$ 31,920		$ (31,920) a	$ 58,988		$ (58,988) a	$ 920,747		$ (920,747) a	$ 30,858		$ (30,858) a			$ - a	$ 17,881		$ (17,881) a

a Vegetation Management work is not budgeted as a specific item on a capital projects.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 78

Responding Witness: Daniel K. Arbough

Q-78. Refer to Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) I. Page 214 of 235.

a. Explain why the Companies expect a $3.5M increase in "Total O&M Expense – Mgmt. View" between actual 2017 and forecast 2018. Any response should explain the more than $2M increase in "Outside Counsel" between the two periods.

A-78.

a. Labor savings in 2017 were driven by one vacant position in legal that was being held due to assessment of need; and, due to the timing of hiring the Executive Vice President General Counsel. Both of these positions have now been filled.

Outside Counsel spend for 2017 was atypical due to total spend being $1.2 million less than the average of the prior five years. There were extended periods of minimal activity due to timing issues in two litigation matters that were beyond the Company's control.

Outside Services/Legal Expert Fees are significantly higher in 2018 due primarily to two matters.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 79

Responding Witness: Daniel K. Arbough

Q-79. Refer to Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) I. Page 215 of 235.

a. Explain the significant increase in "Regulatory" expenses between the actual 2017 expenses and the increase to 2018 forecast and further increase in 2019 and beyond.

b. Explain the doubling of "All Other" expenses for 2018 forecast compared to 2017 actual.

A-79. In 2017, actual spend was atypically lower than actual spend seen in the prior five years.

a. The increase from 2017 Regulatory to 2018 Regulatory is driven by five separate matters forecasted at over \$100k each. The increase from 2018 to 2019 is due to six matters forecasted at over \$100K (including three matters over \$400k each).

b. The increase in All Other for 2018 is driven by a single matter forecasted at over \$500k. The remaining increase is spread across over 100 matters.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 80

Responding Witness: Daniel K. Arbough

Q-80. Refer to Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) I. Page 213 of 235, wherein "Major Assumptions" for the 2019 General Counsel Operating Plan states in part:

External Affairs

- Expectation that at least one 2019 legislative issue will require modest outside communications agency spending
- Convergence of legislative, regulatory and legal issues expected to continue (e.g. Solar Share and Planning and Zoning legislation, change in Basic Service Charge and legislations limiting the same, potential change in net metering statute requiring filing of new tariffs, etc.).

a. Are the Companies requesting recovery of anticipated costs of engaging on legislation, including "communications agency spending" in the forecasted period?

A-80.

a. The companies are not requesting recovery of anticipated costs of engaging on legislation, including "communications agency spending" in the forecasted period. These costs are included in non-recoverable accounts.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

Case No. 2018-00295

Question No. 81

Responding Witness: Daniel K. Arbough

Q-81. Directors' and Officers' ("D&O") Liability Insurance: Does the cost of service include any premium costs for D&O insurance either direct charged or allocated? If the response is in the affirmative, provide the following items:

a. Amount included in the base year and forecasted period. If the amount is allocated, provide the allocations.

b. List of officers and directors covered by the insurance.

c. List of acts covered by the insurance.

A-81. Yes, the cost of service includes premium costs for D&O insurance.

a. The amount included in the base year for LG&E is $246,454. The amount included in the forecasted period for LG&E is $240,936. One third of the premium is first allocated from PPL to LG&E and KU Energy LLC ("LKE"). LKE further allocates 46% of the LKE portion of the premium to LG&E.

b. All directors and officers of PPL Corporation and each subsidiary, and employees regardless of job title, if employee is involved in an outside non-profit board or industry association at the request of PPL Corporation or a subsidiary are covered by this insurance.

c. PPL maintains broad directors and officers liability insurance that is designed to indemnify the directors and officers of PPL Corporation and each of its subsidiaries against any liability (including legal expenses, settlements and judgments) arising out of alleged wrongful acts, errors or omissions committed while managing corporate affairs.

PPL's D&O insurance is comprised of Corporate Indemnification and Side A coverages. Corporate Indemnification coverage will reimburse a company for payments made to directors and officers under the indemnification provisions of the company's bylaws. In situations where a company is unable to indemnify a director or officer, such as in the case of a derivative claim brought on behalf of the company by a third party, or in the case of the company's financial inability to pay, Side A coverage provides, on a direct basis and with no deductible, payments for legal expenses, settlements and judgments.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 82

Responding Witness: Robert M. Conroy

Q-82. Refer to the direct testimony of Paul W. Thompson, page 10, wherein he states the "Companies are long-standing supporters of and leaders in economic development in Kentucky."

a. Do the Companies recover through rates specific expenses, investments, monies, salaries, etc. dedicated exclusively or in part to economic development activities?

b. If the response to 4 (a), above, is in the affirmative, indicate where in the Companies' applications those monies are located.

A-82.

a. Yes.

b. The Company's Economic Development departmental expenses are reflected within account 901 Supervision expense.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 83

Responding Witness: Lonnie E. Bellar

Q-83. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 32 of 40, Appendix D, wherein the document discusses the Companies' "plans and processes . . . to address current and future environmental and regulatory requirements."

a. Cite to the portion of the Exhibit where the Companies compared the costs and benefits associated with this variable, particularly where they compared their own "plans and processes" to those that would be administered or adhered to if they were members in an RTO, such as those envisioned by EKPC.

A-83.

a. The Companies have not performed this specific comparison. However, the Companies continually evaluate environmental and regulatory requirements, and regularly review their internal plans processes to address these to ensure that the requirements are met at the least reasonable cost. The Companies also monitor and maintain a working knowledge of the RTOs' plans and processes, evaluate their applicability to the Companies, and reevaluate their internal plans and processes as warranted.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 84

Responding Witness: Daniel K. Arbough

Q-84. Does the Company use credit cards that include rebates? If the response is in the affirmative, provide the following items:

a. Amount of rebate reflected in the cost of service base year and forecasted period. If the amount is allocated, provide the allocations.

b. Actual credit card rebates by year for 2016, 2017, and 2018 YTD. For each year, state the expense accounts where these credit card rebates are reflected and provide a detailed breakdown of those expense accounts.

A-84. Yes.

a. Zero is reflected in the cost of service for the base and forecasted period.

b. The rebate for 2016 was $237,347.75 and the 2017 rebate was $242,836.84. The rebates are recorded in account 921. The rebate for 2018 has not yet been received.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 85

Responding Witness: Christopher M. Garrett

Q-85. Regarding uncollectibles:

a. Explain how the Bad Debt Expense of 0.18% used in the development of Schedule H-1 was derived. Provide the supporting documentation for the derivation.

b. Why is KU and LG&E (gas and electric) bad debt expense used on Schedule H-1 the same if the actual history of bad debt is different as shown in the response to PSC-1-49?

c. Refer to the 2015 Gas Operations % of bad debt to revenue: Explain why the Reserve Account balance was significantly higher in 2015 than the Reserve in 2016 and 2017.

A-85.

a.

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	6,863,748,335	12,541,058	0.182%

b. KU and LG&E (gas and electric) bad debt expense used on Schedule H-1 is not the same. The KU "Uncollectible Accounts Expense" as reported on Schedule H-1 is 0.316% (see the response to Q-85 for KU for derivation), whereas the LG&E (gas and electric) "Uncollectible Accounts Expense as reported on Schedule H-1 is 0.182%.

c. The "Reserve Balance at Beginning of Year" for Gas Operations in 2015 was high as a result of the polar vortex that occurred in the first quarter of 2014. This weather event drove customer bills high and thus resulted in a higher percentage of customer charge-offs related to non-payment. The calculation used to generate the reserve for uncollectibles is driven by a historical net charge-off percentage that decreased in 2016 and 2017, as depicted in part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 86

Responding Witness: Christopher M. Garrett

Q-86. Is it possible, based on the cost allocation manual and service agreements in place, for more than one service company (among LKS, PPL Services, and PPL EU Services) to provide the same kind of services to KU and LG&E?

a. If the response is in the affirmative, fully describe the safeguards in place to prevent more than one service company from allocating duplicate charges for the same service.

b. If the response is in the negative, fully explain the delineation and differentiation of services provided by each service company.

A-86. Yes.

a. During the preparation of the annual budget, LKS Financial Planning and Analysis develops an understanding of the specific services to be provided by LKS, PPL Services, and PPL EU Services and whether these services will benefit KU and LG&E. Extra scrutiny is applied to budgeted charges from departments which exist at both LKS and at either of the two PPL service companies to prevent the duplication of services from being charged to KU and LG&E. Charges which do not benefit KU and LG&E (for such reasons as not being specifically identifiable, attributable to other affiliates, or duplicative) are not budgeted or charged to KU and LG&E. The direct charges bills received from PPL Services and PPL EU Services clearly delineate the source departments from which the charges originate. Actual direct charges are reviewed monthly by the LKS Corporate Accounting, Treasury, Forecasting and Budgeting-Corporate, and Budgeting and Forecasting-Distribution Ops/Customer Services Departments to ensure that charges are billed as expected.

b. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 87

Responding Witness: Robert M. Conroy

Q-87. Provide a narrative explaining the details and how the amounts were estimated for the categories as shown on the Schedules of Rate Case Preparation Costs (Response to Question No. 59[b]). In the narrative, provide purpose and give examples. For example, regarding the Newspaper Advertising category, explain the purpose and content of the advertising, how many newspapers are involved, how many ads and iterations per paper are required, and what the average cost per ad is.

A-87. The Company is required by 807 KAR 5:11.Tariffs Section 8 (2)(b)3 "Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area," to notify customers of any change in a charge, fee, condition of service, or rule regarding the provision for service or the quality, delivery, or rendering of customer's service. The Newspaper Advertising expenses listed on the Schedules of Rate Case Preparation Costs depict the costs associated with publishing said notices. The notices provided by the Company were posted in eighteen (18) newspapers within the Company service territory as ads, and were circulated as required.

Furthermore, the price of placing ads varies per newspaper. For each newspaper, the expenditure ranges from $1,062.96 to $21,538.56 per week. The Certificate of Completed Notice was filed in this proceeding on November 9, 2018.

In addition, the Companies require the assistance of law firms and consultants in preparation of the rate case application.

See the response to PSC 1- 59(b) for a discussion on the basis of the projections.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 88

Responding Witness: Robert M. Conroy

Q-88. Reference Case No. 2018-00120,[13] in which the named complainants alleged that LG&E-KU paid for certain advertisements regarding House Bill 227 of the 2018 General Assembly, Regular Session (Ky. 2018), for the purpose of promotional, political or institutional advertising as set forth in 807 KAR 5:016.

a. State whether one or both companies are seeking rate recovery for any expenses associated with the running of these advertisements or these type of advertisements. If the response is in the affirmative, provide the amount thereof and identify where in the application these expenses can be found.

A-88.

a. No, the Companies are not seeking rate recovery for any expenses associated with the running of the cited advertisements or similar advertisements.

[13] In re: Complaint of Andy McDonald, et al., vs. Kentucky Utilities and Louisville Gas & Electric. Co.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 89

Responding Witness: Lonnie E. Bellar

Q-89. State whether LG&E-KU considered any alternatives to moving to a cycle-based transmission vegetation management plan. If alternatives were considered, identify the alternatives, discuss their respective merits, and state why the Companies rejected them.

A-89. As described in the Transmission System Improvement Plan (TSIP), LG&E and KU retained Environmental Consultants Inc. (ECI) to conduct a comprehensive assessment of the company's existing vegetation management program and make recommendations to align the companies' program with industry best practices. One of the key recommendations from this assessment was the transition to a cyclical program. LG&E and KU did not consider alternatives to this recommendation beyond the previous approach of just in time clearing. LG&E and KU also described in the TSIP that the just in time approach of clearing based on frequent inspections was no longer sufficient to address the risk of grow-ins or danger trees falling on lines from outside the maintained boundaries of the easement.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 90

Responding Witness: Robert M. Conroy

Q-90. Confirm that in LG&E rate case 2003-00433, the Commission in its Final Order dated June 30, 2004,[14] relying in part on data broken down by NARUC operating expense category, at p. 51-52 removed 45.35% of LG&E's dues paid to Edison Electric Institute ("EEI"), for a total exclusion of $88,614, because EEI applied that portion of the dues LG&E paid toward: (i) legislative advocacy; (ii) regulatory advocacy; and (iii) public relations [hereinafter jointly referred to as "covered activities"].

A-90. The Commission's order speaks for itself. The cited pages contain the information quoted above, but do not refer explicitly to NARUC operating expense categories.

[14] Accessible at: https://psc.ky.gov/order_vault/Orders_2004/200300433_06302004.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 91

Responding Witness: Christopher M. Garrett

Q-91. Confirm that since 2007, EEI no longer prepares the same breakout of its activities by NARUC operating expense category.

a. For each rate case since 2007, provide the allocation the Companies utilized in determining the exclusion of particular EEI dues.

b. Provide a narrative explanation of the bases used for each rate case allocation provided in response to subpart a., above.

A-91. LG&E does not rely upon any NARUC reports or other studies for the exclusion from or inclusion in rates of a portion of any organizations dues. LG&E relies on information provided on the invoices received from any organization in order to determine the portion of dues that should be excluded from rates.

a. Following are the allocations that LG&E has used since 2007:

Per books	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	18%	18%	22%	27%	23%	20%	15%	14%	14%	14%
Per rate cases	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	18%			27%		20%		14%		14%

b. The invoices received from EEI are used to determine the allocation used for ratemaking purposes.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 92

Responding Witness: Christopher M. Garrett

Q-92. Reference FR 16(8)(f), Sch. F-1 of the current application.

c. Confirm that in the base period, LG&E paid $309,928.90 in dues to EEI, and excluded $46,792.28.

d. Confirm that for the forecasted period, LG&E seeks to recover $306,562.76 of the dues it believes it will pay to EEI, and to exclude $52,553.68.

e. Confirm that for both the base period and the forecasted test period, EEI has engaged in, and will continue to engage in, inter alia, covered activities.

f. Since EEI no longer breaks out its activities by NARUC operating expense category, provide the basis for LG&E's proposed exclusion of $52,553.68 in EEI dues from the forecasted test period. Provide copies of all documents supporting both the amount of LG&E's proposed exclusion, and the amounts of EEI dues LG&E suggests should be included for recovery.

g. Confirm that based on Commission precedent of excluding 45.35% of EEI dues, LG&E should exclude $167,536.55 from the forecasted period.

A-92.

c. Yes, amounts are confirmed.

d. Yes, amounts are confirmed.

e. LG&E cannot confirm the activity of EEI, but it is assumed in the forecast they will continue their current activities.

f. Based on the invoice for the EEI membership in 2018, 13% of membership dues and 24% of industry issues should be excluded from the cost of service as those expenses relate to influencing legislation. The combined exclusion of the invoice amount is 14%, which is appropriately applied to the forecasted test period. See the response to question 98 for a copy of the invoice.

The 2019 estimate was provided by PPL. The amount excluded for the forecasted test period was 14% of the amount provided.

g. No, the Company does not agree with this position. LG&E excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI. See the response to Question No. 91(b).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 93

Responding Witness: Christopher M. Garrett

Q-93. Reference FR 16(8)(f), Sch. F-1.

h. For the Base Period category, fully identify each vendor falling into the "Various Vendors" and "Other Non-Specific LG&E Dues" categories, as to both recoverable and not recoverable dues.

i. For both the base and forecasted periods, fully identify all vendors falling in the "Other Non-Specific LG&E Dues" category.

j. Confirm whether Electric Power Research Institute (EPRI) engages in any one or all of the covered activities. If confirmed as to any one or more of such covered activities, provide the amount of LG&E dues that EPRI applies to the covered activities, both in dollar terms and percentages of total dues.

k. Confirm that Hunton & Williams, LLP has a lobbying arm/affiliate. Identify the amount of LG&E dues this organization applies toward covered activities, both in terms of dollars and percentages of total dues.

l. Explain whether North American Transmission Forum engages in covered activities. If so, identify the amount of LG&E dues this organization applies toward covered activities, both in terms of dollars and percentages of total dues.

m. Explain whether Steptoe & Johnson LLC engages in covered activities. If so, identify the amount of LG&E dues this organization applies toward covered activities, both in terms of dollars and percentages of total dues.

n. Confirm that the Utility Air Regulatory Group (UAR) engages in covered activities. Identify the amount of LG&E dues that UAR applies toward covered activities, both in terms of dollars and percentages of total dues.

o. Confirm that the Utility Water Act Group (UWAG) engages in covered activities. Identify the amount of LG&E dues that UWAG applies toward covered activities, both in terms of dollars and percentages of total dues.

p. Explain whether the Midwest Ozone Group (MOG) engages in covered activities. If so, identify the amount of LG&E dues MOG applies toward covered activities, both in terms of dollars and percentages of total dues.

q. Explain whether the Utility Solid Waste Activities Group (USWAG) engages in covered activities. If so, identify the amount of LG&E dues that USWAG applies toward covered activities, both in terms of dollars and percentages of total dues.

r. Confirm that the American Gas Association ("AGA") engages in covered activities. Identify the amount of LG&E dues that AGA applies toward covered activities, both in terms of dollars and percentages of total dues.

A-93.

h. See attached the breakdown of vendors falling into "Various Vendors" for both recoverable and not recoverable dues. As indicated in FR 16(8)(f), Sch. F-1, portions of the Base Period Recoverable and Non-Recoverable Dues are not completed in specific vendor detail.

i. As indicated in FR 16(8)(f), Sch. F-1, portions of the Forecasted Period Recoverable and Non-Recoverable Dues are not completed in specific vendor detail.

j. Electric Power Research Institute (EPRI) does not engage in any covered activities.

k. Coal Combustion Residuals (CCR) Legal Resources Group and New Source Review (NSR) Legal Resources Group are billed through Hunton & Williams, LLP. Both groups are not engaged in covered activities.

l. North American Transmission Forum does not engage in covered activities.

m. Steptoe & Johnson LLC is an agent of Midwest Ozone Group that engages in covered activities.

n. Utility Air Regulatory Group (UARG) engages in covered activities.

o. Utility Water Act Group (UWAG) engages in covered activities.

p. Midwest Ozone Group (MOG) engages in covered activities.

q. Utility Solid Waste Activities Group (USWAG) engages in covered activities.

r. American Gas Association ("AGA") engages in covered activities. For the year 2018, 3.1% of AGA dues or $6,552 are non-recoverable.

Breakdown of "Various Vendors" - Recoverable

Vendor Name	Employee Dues
BOSTON COLLEGE	2,300.00
THE INSTITUTE OF INTERNAL AUDITORS	2,221.86
NACE INTERNATIONAL INSTITUTE	1,880.00
LOUISVILLE BAR ASSOCIATION	1,186.80
INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS (IEEE)	1,044.38
PROJECT MANAGEMENT INSTITUTE (PMI)	824.32
ENERGY AND MINERAL LAW	818.40
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	779.58
TANDEM SOLUTION	668.80
HODGENVILLE ROTARY CLUB	660.71
WEATHERBELL ANALYTICS	629.20
WSI CORPORATION	600.00
INDUSTRIAL ASSET MANAGEMENT COUNCIL, INC	592.20
SURVEY SITE	510.00
INFORMATION SYSTEMS SECURITY	507.00
KENTUCKY STATE BOARD OF LICENSURE FOR PROFESSIONAL ENGINEERS AND LAND SURVEYORS	458.00
AMERICAN BAR ASSOCIATION	429.64
UOFL DELPHI CTR	340.60
AMERICAN BIOGAS COUNCIL	340.32
NSPE (NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS)	338.20
INSTITUTE OF MANAGEMENT ACCOUNTANTS	335.80
AICPA	334.00
SOS INT'L LLC	331.50
PROFESSIONAL ENGINEERING LICENSE RENEWAL	328.50
CCIM INSTITUTE	308.00
KENTUCKIANA USERS COUNCIL	300.00
THE LAW CLUB	276.00
SUBSTANCE ABUSE PROGRAM ADMINISTRATORS ASSOCIATION (SAPAA)	275.00
ISACA	252.20
PAYROLL PROFESSIONALS OF KENTUCKIANA	250.00
PUBLIC RELATIONS SOCIETY OF AMERICA	231.00
AMERICAN PAYROLL ASSOCIATION	219.00
LEADERSHIP LOUISVILLE	219.00
STATE OF INDIANA	199.30
ENERGY BAR ASSOCIATION	197.80
THE WALL STREET JOURNAL	193.03
SOCIETY OF HUMAN RESOURCE MANAGEMENT	191.50
CGMA & AICPA	186.75
NBMBAA	175.00
INTERNATIONAL ENERGY CREDIT ASSOCIATION (IECA)	156.00
AIR & WASTE MANAGEMENT ASSOCIATION	140.40
ASSOCIATION OF ENERGY ENGINEERS	140.40
SANS INSTITUTE	122.57
AMERICAN SOCIETY OF SAFETY ENGINEERS	122.39
INDIANA CPA SOCIETY, INC.	121.90
CLE CENTER	114.54
ATD (ASSOCIATION OF TALENT DEVELOPMENT)	114.50
INTERNATIONAL RIGHT OF WAY ASSOCIATION	114.40
WOMEN IN DIGITAL PROFESSIONAL ORGANIZATION	110.40
CPA LICENSE RENEWAL	106.11
INSTITUTE OF SUPPLY MANAGEMENT	105.00
TAX EXECUTIVES INSTITUTE	103.50
KENTUCKIANA CHAPTER OF PMI	92.04
KY ASSOCIATION OF MAPPING PROFESSIONALS	91.25
APICS	90.00

Breakdown of "Various Vendors" - Recoverable

Vendor Name	Employee Dues
ACFE	89.70
ARMA (RECORD MANAGEMENT SOCIETY)	87.50
FOREFLIGHT	82.68
ISC2 (CYBERSECURITY AND IT SECURITY PROFESSIONAL ORGANIZATION)	78.00
UTILITY SAFETY & OPS LEADERSHIP NETWORKS (USOLN)	72.50
NFPA NATL FIRE PROTECT	70.00
FORENSIC CPA SOCIETY	69.00
ASSOCIATION FOR THE ADVANCEMENT OF ARTIFICIAL INTELLIGENCE	55.10
CERTIFIED INFORMATION SYSTEMS SECURITY PROFESSIONAL (CISSP)	44.20
AMERICAN SOCIETY OF MECHANICAL ENGINEERS	44.08
PVA OF JEFFERSON COUNTY	44.00
INDIANA STATE BOARD OF PROFESSIONAL ENGINEERS	41.17
DOWNTOWN HENDERSON PARTNERSHIP	39.60
SOCIETY OF WOMEN ENGINEERS	37.05
AXOSOFT	22.54
KENTUCKY SOCIETY OF PROFESSIONAL ENGINEERS	21.28
KENTUCKY STATE TREASURER	13.40
ASSOCIATED PRESS STYLEBOOK	7.04
AMAZON	(13.80)
Total Employee Dues	24,683.83

Vendor Name	Company Dues
UNIVERSITY OF MISSOURI	4,500.00
PJM INTERCONNECTION LLC	3,962.33
CENTER FOR ENERGY WORKFORCE DEVELOPMENT	2,083.34
KENTUCKY CLEAN FUELS COALITION	1,380.00
URBAN LEAGUE OF GREATER CINCINNATI	1,250.00
HUMAN RESOURCE CERTIFICATION PREPARATION (HRCP) MEMBERSHIP	847.50
INDIANA COAL COUNCIL INC	648.00
NATIONAL ELECTRICAL MANUFACTURING ASSOCIATION (NEMA)	633.60
WORLD TRADE CENTER	360.00
MIDCONTINENT INDEPENDENT SYSTEM OPERATOR INC	333.33
INTERNATIONAL AVAYA USERS GROUP	208.00
INTERNATIONAL ASSOCIATION OF IT ASSET MANAGERS	189.80
PLURALSIGHT	155.48
LOUISVILLE CHAPTER OF KSPE	150.00
SURVEY MONKEY	118.44
CINCINNATI COAL EXCHANGE	84.00
PROJECT MANAGEMENT INSTITUTE (PMI)	82.68
INSTITUTE OF HAZARDOUS MATERIALS MANAGEMENT	57.60
ASCAP	57.04
THE ELEARNING GUILD	51.48
THE WALL STREET JOURNAL	41.33
NEXMO LTD	33.36
KENTUCKY STATE TREASURER	2.48
Total Company Dues	17,229.79
Total Company and Employee Dues	41,913.62

Breakdown of "Various Vendors" - Non-Recoverable

Vendor Name	Amount
BULLITT COUNTY CHAMBER OF COMMERCE	1,000.00
CARROLL COUNTY CHAMBER OF COMMERCE	80.00
COMMERCE LEXINGTON	22.05
ENERGY & MINERAL LAW FOUNDATION	198.00
GREATER LOUISVILLE INC.	360.00
INDIANA COAL COUNCIL INC.	72.00
LOUISVILLE BAR ASSOCIATION	315.00
OLDHAM COUNTY CHAMBER OF COMMERCE	300.00
ROTARY CLUB OF LOUISVILLE	850.00
SHELBY COUNTY CHAMBER OF COMMERCE	719.40
THE ECONOMIST NEWSPAPER	68.40
AMERICAN GO ASSOCIATION (USGO)	225.00
Total	4,209.85

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 94

Responding Witness: Robert M. Conroy

Q-94. Provide copies of the Annual Reports of EEI, EPRI, and of every other organization which require the Companies to pay dues [hereinafter collectively referred to as the "Dues Requiring Organizations"] since the conclusion of the Companies' last rate case.

A-94. The Company does not collect and retain the requested information for its corporate files. The documents requested would require an expensive and burdensome electronic search. The requested information is thus not readily available.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

Case No. 2018-00295

Question No. 95

Responding Witness: Christopher M. Garrett

Q-95. State whether the AGA continues to break out dues that its members pay by operating expense category, as was provided in LG&E's responses to post-hearing data requests, item no. 11, in Case No. 2003-00433.[15] Provide the most recent such break-out.

A-95. Yes, see attached.

[15] Accessible at: https://psc.ky.gov/PSCSCF/2003%20cases/2003-00434/KU_Response_051704.pdf

AMERICAN GAS ASSOCIATION
2019 and 2018 BUDGETS

	$ 2019 ALLOCATION	% 2019 ALLOCATION	$ 2018 ALLOCATION	% 2018 ALLOCATION
Expenses				
Communications	$3,551,000	9.51%	$4,826,000	12.11%
Corporate Affairs	$4,603,000	12.32%	$4,971,000	12.47%
Energy Markets, Analysis, and Standards	$4,503,000	12.06%	$5,556,000	13.94%
General and Administrative	$8,298,000	22.22%	$8,491,000	21.31%
General Counsel and Regulatory Affairs	$2,616,000	7.00%	$3,218,000	8.08%
Government Affairs and Public Policy	$4,390,000	11.75%	$4,401,000	11.04%
Industry Finance & Administrative Programs	$1,073,000	2.87%	$1,161,000	2.91%
Operations and Engineering	$8,319,000	22.27%	$7,225,000	18.13%
Expense Budget *	$37,353,000	100.00%	$39,849,000	100.00%

Notes
AGA estimates that lobbying related expenses, as defined under IRC Section 162, will account for 3.1% of member dues in 2018 and 3.5% of member dues in 2019.

* Does not include certain expenses or activities not funded by annual member company dues.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 96

Responding Witness: Christopher M. Garrett

Q-96. For each Dues Requiring Organization, provide: (i) the amount of dues the Companies paid during the base period; (ii) the amount they are asking to be recovered from customers during the forecasted period. Provide the complete basis for LG&E's determination of whether dues should be recoverable or not recoverable.

A-96. See Tab 59 of the Filing Requirements at page 2. Recoverable and non-recoverable dues are trended based on a review of each component of historical dues. Recovery is based on operational benefit to the customer and prior precedent of the Commission.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 97

Responding Witness: Christopher M. Garrett

Q-97. Provide a copy of the formula(s) used to compute, and the actual calculation of the dues the Company paid to each Dues Requiring Organization since the conclusion of the Company's last rate case.

A-97. See attached. Dues are recorded on LG&E's books based on actual invoices received from such organizations.

Company	Vendor Name	Dues Calculation Method
LGE	American Gas Association	Based off Gas Operating Income
LGE	Edison Electric Institute (EEI)	Based on Total Average number of customers served, total revenue, and generation owned capacity
LGE	Electric Power Research Institute (EPRI)	Based on Generator capacity (coal, gas, hydro, nuclear), peak transmission and thru put on distribution.
LGE	University of Louisville Research Foundation Inc.	Calculation not available
LGE	North American Transmission Forum	Load ratio share
LGE	Hunton and Williams LLP (CCR Legal Resources Group)	Flat annual fee
LGE	Hunton and Williams LLP (NSR Legal Resources Group)	Flat annual fee
LGE	Baker Botts LLP (Class of 85 and Cross Cutting Issues)	Flat annual fee
LGE	Steptoe & Johnson LLC (MOG)	Mega Watts & Size of Company (electric generation capacity only)
LGE	Utility Air Regulatory Group (UARG)	Mega Watts & Size of Company
LGE	Utility Water Act Group (UWAG)	Mega Watts & Size of Company (electric generation capacity only)
LGE	Utility Solid Waste Activities Group (USWAG)	Mega Watts & Size of Company
LGE	University of Missouri	Calculation not available (annual membership & board appt)
LGE	Various Vendors and Other non-specific LG&E dues	Calculation not available

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 98

Responding Witness: Christopher M. Garrett

Q-98. Provide a complete copy of invoices received from each Dues Requiring Organization since the conclusion of the Company's last rate case.

A-98. See attached copies of 2017 and 2018 invoices received from Organization Memberships as presented in FR 16(8)(f), Sch. F-1.

File # 401205

AMERICAN GAS ASSOCIATION

Invoice # 115499

Invoice
for
LG&E-KU, PPL Companies

Jan 12, 2018

Dacia Harris
Budget Analyst I
LG&E-KU, PPL Companies
820 W. Broadway
Louisville, KY 40202

DESCRIPTION	AMOUNT
Dues for 2018 membership year: $211,356.00	
Annual Payment	$211,356.00 LGE

REMIT PAYMENT WITH DUPLICATE COPY OF INVOICE TO:

AMERICAN GAS ASSOCIATION
Post Office Box 79226
Baltimore, MD 21279-0226
Telephone (202) 824-7256
Fax (202) 824-9156

IMPORTANT IRS REQUIRED NOTICE

Dues payments, contributions or gifts to the American Gas Association are not tax deductible as charitable contributions for federal income tax purposes. However, they may be deductible as ordinary and necessary business expenses subject to restrictions imposed as a result of AGA's lobbying activities as defined by the Budget Reconciliation Act of 1993. AGA estimates that the nondeductible portion of your 2018 dues – the portion that is allocable to lobbying is 3.1%.

Included with membership is a one-year subscription to American Gas, the subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers and is not deductible from member dues.

File # 401205

AMERICAN GAS ASSOCIATION

Invoice # 104440

Invoice
for
LG&E-KU, PPL Companies

Jan 25, 2017

Gloria Dickson
Budget Analyst
LG&E-KU, PPL Companies
220 West Main Street
Louisville, KY 40202

DESCRIPTION	AMOUNT
Dues for 2017 membership year: $204,426.00	
Annual Payment	$204,426.00

REMIT PAYMENT WITH DUPLICATE COPY OF INVOICE TO:

AMERICAN GAS ASSOCIATION
Post Office Box 79226
Baltimore, MD 21279-0226
Telephone (202) 824-7256
Fax (202) 824-9156

IMPORTANT IRS REQUIRED NOTICE

Dues payments, contributions or gifts to the American Gas Association are not tax deductible as charitable contributions for federal income tax purposes. However, they may be deductible as ordinary and necessary business expenses subject to restrictions imposed as a result of AGA's lobbying activities as defined by the Budget Reconciliation Act of 1993. AGA estimates that the nondeductible portion of your 2017 dues – the portion that is allocable to lobbying is 6.4%.

Included with membership is a one-year subscription to American Gas, the subscription rate for which is $59.00 per year for U.S. and Canadian subscribers and $110.00 per year for international subscribers and is not deductible from member dues.

Received email 1/26/17

BAKER BOTTS LLP

THE WARNER
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20004-2400

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SAN FRANCISCO
WASHINGTON

December 8, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of December 2017.

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,137.50
KU - $1,779.17

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer [redacted]

3538231 1.2

BAKER BOTTS LLP

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December 18, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental
Policy Manager
LG&E and KU Energy LLC
220 West Main Street
PO Box 32010
Louisville, KY 40202

Statement of Fees for Participation in the Class of '85 Regulatory Response Group

Payment for:

January - December 2018	$39,600
TOTAL AMOUNT DUE	**$39,600***

***Please note that if not paid in full by 12/31/2017, the annual fee will increase to $40,800.**

LGE - $ 15,912.00
KU - $ 24,888.00

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

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WASHINGTON

January 8, 2018

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of January 2018.

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,137.50
KU - $1,779.17

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382311.2

BAKER BOTTS L.L.P.

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WASHINGTON

February 8, 2018

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of February 2018.

TOTAL AMOUNT DUE: $2,916.67

LGE - $ 1,137.50
KU - $ 1,779.17

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382311.2

BAKER BOTTS L.L.P.

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March 8, 2018

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of March 2018.

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,137.50
KU - $1,779.17

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382311.2

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DEC 19 2016
LAW DEPARTMENT

December 14, 2016

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
PO Box 32010
Louisville, KY 40202

Inv. No.
C85-121416

Statement of Fees for Participation in the Class of '85 Regulatory Response Group

December 2016	$3,200
TOTAL AMOUNT DUE	**$3,200**

Summary of Activities: Draft and distribute memoranda and emails to members regarding Clean Air Act issues; review status of EPA and citizen group lawsuits based on various Clean Air Act Programs; send summaries to clients of various Clean Air Act actions; review Federal Register notices and EPA guidance; request clarifications from EPA on various rules; correspondence with EPA staff regarding recent regulatory developments; respond to client questions regarding various Clean Air Act developments.

Please remit to:

LGE – $1,216.00

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

KU – $1,984.00

Taxpayer I.D. [redacted]

Active 24760494.1

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SAN FRANCISCO
WASHINGTON

December 14, 2016

Inv. No. ~~[illegible]~~

Mr. Robert J. Ehrler
Senior Counsel and Environmental
Policy Manager
LG&E and KU Energy LLC
220 West Main Street
PO Box 32010
Louisville, KY 40202

Statement of Fees for Participation in the Class of '85 Regulatory Response Group

Payment for:

January - December 2017	$38,400
TOTAL AMOUNT DUE	**$38,400***

*Please note that if not paid in full by 12/31/2016, the annual fee will increase to $39,600.

Please remit to:

LGE - $15,048
KU - $24,552

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

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January 12, 2017

Invoice #
~~CCI 01 12 17~~

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of January 2017

TOTAL AMOUNT DUE: $2,916.66

LGE - $1,108.33
KU - $1,808.33

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

32023375.1

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BAKERB 02 1017

February 10, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of February 2017

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,108.33
KU - $1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

33422162.1

BAKER BOTTS LLP

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March 7, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of March 2017.

TOTAL AMOUNT DUE: $2,916.67

LGE - 1,108.33
KU - 1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

34284097.1

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April 12, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of April 2017.

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,108.33
KU - $1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35199804.1

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May 5, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of May 2017.

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,108.33
KU - $1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382163.1

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BAKERB 060577
6/5/17

June 5, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of June 2017.

TOTAL AMOUNT DUE: **$2,916.67**

LGE - $1,108.33
KU - $1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382294.1

BAKER BOTTS LLP

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July 5, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

BAKERB071217

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of July 2017.

TOTAL AMOUNT DUE: **$2,916.67**

LGE - $1,108.33
KU - $1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382298.1

BAKER BOTTS LLP

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August 4, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of August 2017.

TOTAL AMOUNT DUE: $2,916.67

LGE - $1,108.33
KU - $1,808.34

Please remit to:

Baker Botts L.L.P.
P.O. Box 301251
Dallas, TX 75303-1251

Taxpayer I.D. [redacted]

35382311.1

Invoice for Membership Dues

EEI
Edison Electric INSTITUTE

Mr. William H. Spence
Chairman, President & CEO
PPL Corporation
2 N 9th Street
Allentown, PA 18101

Date	Invoice Number
12/13/2017	DUES201850

Payment due on or before 1/31/2018

Description	Total
2018 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1]	$1,171,634
Industry Issues [2]	117,163
Restoration, Operations, and Crisis Management Program [3]	15,000
2018 Contribution to The Edison Foundation, which funds IEI [4]	A 30,000
Total	**$1,333,797**

1 The portion of 2018 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2018 industry issues support relating to influencing legislation is estimated to be 24%.

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry–wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:
Bank's Address:
Bank's ABA Number:
Beneficiary:
Beneficiary's Acct No:
Beneficiary's Address:
Beneficiary Reference:

[redacted]

1,333,797
A<30,000>
1,303,797
x .65
847,468.05
LGE * 345,612.7[illegible]
KU * 501,855.30

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

Indirect (CATGB) 2018
2) Office of Chairman

January-December 2018 EEI Membership Dues (invoice attached)
$1,153,181 This payment will be amortized 1/12 to expense each month at PPL Financial and will be allocated to the Business Lines as a Category B cost.

Total for year $1,303,797 — p4
65% to Kentucky (Category B) 65.00% — p7, 9
$847,468.05

Jan-Dec 2017 cost to Kentucky for EEI Membership Dues $847,468.05
Rounded to $847,468.00 — p6

Journal Entry Calculation		
Allocation	Amount	Company
p3 40.77%	$ 345,512.70	LGE p1
59.23%	$ 501,955.30	KU
Total	$ 847,468.00	

2018's EEI Dues allocation % is based on 2016's %

		Calculation of LKE EEI Dues		
		Non-Lobbying	Lobbying	Contribution
Total for year	$1,153,181.00 D	1,123,365.46 A	180,431.54 B	- C
1/12 Amortization each month	8.33%	8.33%	8.33%	0
PPL Financial expense each month	$98,058.42	$93,613.79	$15,035.96	$0.00
65.00% to Kentucky	65.0%	65.00%	65.00%	65.00%
Estimated cost to Kentucky each month for EEI Membership Dues	$62,483.97	$60,848.96	$9,773.37	$0.00
Estimated Category B cost to Kentucky in 2018 for EEI Membership Dues	$749,587.64	$730,187.52	$117,280.44	Expensed not amortized $0.00

Amortization Period: January 2018 - December 2018

Allocation	Amount	Company	Project	Task	Account	Exp Type	Exp Org
40.77%	$ 24,808.12	LGE	119013	EEI GC	930272	0664	026910
59.23%	$ 36,040.84	KU	119012	EEI-GC	930272	0664	026910
40.77%	$ 3,984.60	LGE	119013	EEI Lobby	426491	0664	026910
59.23%	$ 5,788.77	KU	119012	EEI-Lobby	426491	0664	026910

Total amount to be amortized per month
62,483.97

Rounded to	24,808.12
	36,040.84
	3,984.60
	5,788.77
	70,622.33
x12 months LGE	297,697.44
KU	432,490.08
LGE	47,815.20
KU	69,465.24
	847,467.96 <- will need true-up at the end of 2018 once recalculation is completed

Calculation of PPL EEI Dues — p4, 9

	Regular Activities	$	1,171,634.00 — p4, 9
p4 — 13%	Lobbying	$	152,312.42
	EEI Dues	$	1,019,321.58
	Industry Issues	$	117,163.00 — p4
p4 — 24%	Lobbying	$	28,119.12
	EEI Dues	$	89,043.88
	Restore Power	$	15,000.00 — p41
	Contribution to Edison Foundation	$	-
	Lobbying Total	$	180,431.54 B
	Contribution Total	$	- C
	EEI Dues Total	$	1,123,365.46 A
	Total Invoice	$	1,303,797.00 D

p4

Y:\ENERGY\SERVCO\Journal Entries\2018 Journal Entries\01 January 2018\J001-0020-0118 EEI Dues.xlsm Original 2018 Amounts to RAR

2

Invoice for Membership Dues

Edison Electric INSTITUTE

MR. WILLIAM H. SPENCE
CHAIRMAN, PRESIDENT & CEO
PPL CORPORATION
2 N 9TH STREET
ALLENTOWN, PA 18101

Date	Invoice Number
12/07/2016	DUES201752

Payment due on or before 1/31/2017

Description	Total
2017 EEI Membership Dues for:	
Regular Activities of Edison Electric Institute [1]	$1,153,181
Industry Issues [2]	115,318
Restoration, Operations, and Crisis Management Program [3]	15,000
2017 Contribution to The Edison Foundation, which funds IEI [4]	A ~~30,000~~ e
Total	1,283,499 ~~$1,313,499~~

1 The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%. /2

2 The portion of the 2017 Industry Issues support relating to influencing legislation is estimated to be 26%. /2

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry-wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank:
Bank's Address:
Bank's ABA Number:
Beneficiary:
Beneficiary's Acct No:
Beneficiary's Address:
Beneficiary Reference:
[redacted]

1,313,499
<30,000> A
1,283,499
x .66
847,109.34
LGE # 353,427.04
KU # 493,681.96

Approved for Payment:

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

Indirect (CATGB) 2017
2) Office of Chairman

January-December 2017 EEI Membership Dues (Invoice attached)
$1,283,499 This payment will be amortized 1/12 to expense each month at PPL Financial and will be allocated to the Business Lines as a Category B cost.

Total for year		4|	$1,283,499
	66% to Kentucky (Category B)	5|	66.00%
			847,109.34
Jan-Dec 2017 cost to Kentucky for EEI Membership Dues			$847,109.34
	Rounded to	5|	847,109.00

Journal Entry Calculation

Allocation	Amount	Company	
41.72%	$ 353,427.04	LGE	1|
58.28%	$ 493,681.96	KU	1|
Total	$ 847,109.00		

2017's EEI Dues allocation % is based on 2015's %

			Calculation of LKE EEI Dues		
			Non-Lobbying	**Lobbying**	**Contribution**
Total for year		$1,283,499.00 D	1,104,755.97 A	178,743.03 B	- C
	1/12 Amortization each month	8.33%	8.33%	8.33%	0
PPL Financial expense each month		$106,958.25	$92,063.00	$14,895.25	$0.00
	66.00% to Kentucky	66.0%	66.00%	66.00%	66.00%
Estimated cost to Kentucky each month for EEI Membership Dues		$70,592.45	[illegible]0,761.59	$9,830.67	[illegible]0.00
					Expensed not amortized
Estimated Category B cost to Kentucky in 2016 for EEI Membership Dues		[illegible]47,109.40	$729,138.96	$117,970.44	$0.00

Amortization Period: January 2016 - December 2016

Allocation	Amount	Company	Project	Task	Account	Exp Type	Exp Org
41.72%	$ 25,350.68	LGE	119013	EEI GC	930272	0684	026910
58.28%	$ 35,410.90	KU	119012	EEI-GC	930272	0684	026910
41.72%	$ 4,101.59	LGE	119013	EEI Lobby	426491	0684	026910
58.28%	$ 5,729.28	KU	119012	EEI-Lobby	426491	0684	026910

Total amount to be amortized per month
70,592.45

Rounded to		25,350.68
		35,410.90
		4,101.59
		5,729.28
		70,592.45
x12 months	LGE	304,208.16
	KU	424,930.80
	LGE	49,219.08
	KU	68,751.36
		847,109.40 <- will need true-up at the end of 2017 once recalculation is completed

Calculation of PPL EEI Dues

		Regular Activities	$	4| 1,153,161.00	
4|	13%	Lobbying	$	149,913.53	
		EEI Dues	$	1,003,267.47	
		Industry Issues	$	4| 115,318.00	
4|	25%	Lobbying	$	28,829.50	
		EEI Dues	$	86,488.50	
		Restore Power	$	4| 15,000.00	
		Contribution to Edison Foundation	$	-	
		Lobbying Total	$	178,743.03	B
		Contribution Total	$	-	C
		EEI Dues Total	$	1,104,755.97	A
		Total Invoice	$	1,283,499.00	D

U:\ENERGY\SERVCO\Journal Entries\2017 Journal Entries\(01) January 2017\J001-0020-0117 EEI Dues.xlsm Original 2017 Amounts to RAR

ELECTRIC POWER RESEARCH INSTITUTE

INVOICE

Invoice: 90022357
Invoice Date: 01/18/2018
Page: 2 of 2

P.O. Box 10412
Palo Alto CA 94303-0813
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

Customer: David Link
LG&E and KU Energy LLC
220 W Main St
Louisville KY 40202-1395
USA

AMOUNT DUE: 3,455,281.36 USD

19	Protection and Control	1	EA	23,098.48
20	Energy Storage and Distributed Generation	1	EA	130,011.15
21	Distribution Operations and Planning	1	EA	79,266.77
22	Technical Deployment	1	EA	44,470.43
	Deposit Account			247,469.00
			Subtotal:	3,455,281.35
			Amount Due:	3,455,281.36 USD

CPA# 116812 PO# ______________

Project	Task	Exp Type	$$ or % Split
133671	EPRI	0305	$ 82,640.21
133679	EPRI	0305	$ 82,640.21
SRC153955	I-Prepaid	0305	$3,290,000.93

KU - 2,039,800.58
LGE - 1,250,200.35

David J. Link, Ph.D. - Manager R&D — Date 1/30/18

David Sinclair - VP Energy Supply and Analysis — Date 1-30-18

Actual amount is $1.51 lower than amount forecasted in Filing Requirement 16(8)(f).

Lonnie Bellar - SVP Operations — Date 1/30/18

Kent Blake - CFO — Date 1/30/18

Please wire funds to:
Bank of America
[redacted]

Please remit check to:
Electric Power Research Institute
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. [redacted]
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

INVOICE

Invoice: [illegible]
Invoice Date: 01/17/2017
Page: 2 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: 02/16/2017
Customer Ref:
EPRI Quotation No: 20006982

For billing questions, please contact:

Telephone: 650-855-2048
Fax: 650-855-2358
Email: accountsreceivable@epri.com

AMOUNT DUE: **4,716,825.78 USD**

	Environmental Issues			
20	Transmission and Distribution and ROW Environmental Issues	1	EA	107,448.60
21	Fish Protection at Electric Generating Facilities	1	EA	129,284.78
22	Effluent Guidelines and Water Quality Management	1	EA	121,214.48
23	Protection and Control	1	EA	24,591.02
24	Electric Transportation	1	EA	109,181.27
25	Energy Storage and Distributed Generation	1	EA	116,093.76
26	Cyber Security and Privacy	1	EA	131,187.56
	Deposit Account			851,234.00
			Subtotal:	4,716,825.78
			Amount Due:	**4,716,825.78 USD**

4,716,825.78
<81,196.94>
<81,196.94>
4,554,431.90 < KU - *2,869,292.10
LGE - *1,685,139.80

Please wire funds to:
Bank of America
[redacted]

Please remit check to:
EPRI
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. [redacted]
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

ELECTRIC POWER RESEARCH INSTITUTE

INVOICE

Invoice: 90017191
Invoice Date: 01/17/2017
Page: 1 of 2

P.O. Box 10412
Palo Alto CA 94303-0813
USA

Customer No: 30166
Payment Terms: EPRI - Net due in 30 days
Due Date: 02/16/2017
Customer Ref:
EPRI Quotation No: 20006982

Customer: David Link
LG&E and KU Energy LLC
220 W Main St
Louisville KY 40202-1395
USA

For billing questions, please contact:

Telephone: 650-855-2048
Fax: 650-855-2358
Email: accountsreceivable@epri.com

AMOUNT DUE: **4,716,825.78 USD**

Line	Description	Quantity	UOM	Net Amount
1	Integrated Environmental Controls	1	EA	545,222.51
2	Continuous Emissions Monitoring	1	EA	107,209.72
3	Heat Rate Improvement	1	EA	87,172.52
4	Water Management Technology	1	EA	162,393.87
5	Boiler Life and Availability Improvement	1	EA	172,726.19
6	Steam Turbines-Generators and Auxiliary Systems	1	EA	137,162.72
7	Balance of Plant Systems and Equipment	1	EA	36,829.86
8	Boiler and Turbine Steam and Cycle Chemistry	1	EA	103,875.96
9	Fossil Materials and Repair	1	EA	155,516.02
10	Combined Cycle Turbomachinery	1	EA	306,031.04
11	Combined Cycle HRSG and Balance of Plant	1	EA	107,086.21
12	Maintenance Management and Technology	1	EA	142,793.57
13	Operations Management and Technology	1	EA	127,277.81
14	CO2 Capture, Utilization and Storage	1	EA	179,981.32
15	Renewables Technology Status, Cost and Performance	1	EA	62,798.67
16	Solar	1	EA	116,626.10
17	Power Plant Multimedia Toxics Characterization	1	EA	207,200.39
18	Assessment of Air Quality Impacts on Human Health	1	EA	202,700.52
19	Coal Combustion Products -	1	EA	165,985.31

Please wire funds to:
Bank of America
[redacted]

Please remit check to:
EPRI
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. [redacted]
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

EPRI Annual Membership

Contract Period:	01/01/2017 - 12/31/2017
Contact:	Courtney Suyeyasu
Vendor:	EPRI
Invoice #:	90017191
Invoice Amt.:	$ 4,716,825.78
Invoice Date:	01/17/2017

						January - April 2017 Allocation Method: 124651 I-PREPAID			January - April 2017 Allocation Method: 124652 I-PREPAID		May - December 2017 Allocation Method: 124651 I-PREPAID		May - December 2017 Allocation Method: 124652 I-PREPAID	
Company	Exp Org	Exp Type	Project	Task	Amount	Monthly	KU Amort.		LGE Amort.		KU Amort.		LGE Amort.	
0100	008825	0375	133671	EPRI	$ 81,196.94	$ 6,766.41	$ -		$ 6,766.41		$ -		$ 6,766.41	
0100	008825	0375	133679	EPRI	$ 81,196.94	$ 6,766.41	$ -		$ 6,766.41		$ -		$ 6,766.41	
0020	022070	0650	SRC153955	EPRI-274	$ 3,703,197.90	$ 308,599.83	$ 194,417.89	63.00%	$ 114,181.94	37.00%	$ 191,331.89	62.00%	$ 117,267.94	38.00%
0020	022070	0650	SRC153955	EPRISUP	$ 851,234.00	$ 70,936.17	$ 44,689.79	63.00%	$ 26,246.38	37.00%	$ 43,980.43	62.00%	$ 26,955.74	38.00%
					4,716,825.78	$ 393,068.82	$ 239,107.68		$ 153,981.14		$ 235,312.32		$ 157,756.50	

	Servco				LGE			
	Exp Org	Exp Type	Project	Task	Exp Org	Exp Type	Project	Task
Amortization	022070	0650	SRC124652	I-PREPAID	008825	0650	124652	I-PREPAID

	Prepaid KU	Prepaid LGE	4 Month Amortizatio	4 Month Amortization L(	Prepaid KU Balance	Prepaid LGE Balance
3,703,197.90	2,333,014.68	1,370,183.22	777,671.57	$ 456,727.75	1,555,343.11	913,455.47
851,234.00	536,277.42	314,956.58	178,759.15	$ 104,985.53	357,518.27	209,971.05
	2,869,292.10	1,685,139.80			1,912,861.38	1,123,426.52

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA
101 SOUTH TRYON STREET
SUITE 3500
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: NLONG@HUNTON.COM

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: BROSSER@HUNTON.COM

FILE NO: 86837.000002

December 20, 2017

Confidential
Attorney-Client Privilege

J. Gregory Cornett
Associate General Counsel
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

Re: **Coal Combustion Residuals Legal Resources Group**

Retainer for services in connection with the
Coal Combustion Residuals Legal Resources Group for 2018 ....$70,000

PLEASE REMIT PAYMENT BY JANUARY 20, 2018
USE ONE OF THE BELOW METHODS OF PAYMENT

Check Via First-Class Mail

Hunton & Williams LLP
Attention: Kathy Robinson
2200 Pennsylvania Avenue, NW
Washington, DC 20037
Reference – 2018 CCR Annual Dues/86837.2

Wiring Instructions

Bank:
Account Name:

Account No.
ABA Transit Routing No.
Information with wire
Swift Code (Internat'l)

[redacted]

LGE - $26,600
KU - $43,400

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA
101 SOUTH TRYON STREET
SUITE 3500
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: NLONG@HUNTON.COM

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: BROSSER@HUNTON.COM

FILE NO: 86837.000002

January 3, 2017

Confidential
Attorney-Client Privilege

J. Gregory Cornett
Associate General Counsel
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

~~Invoice No. CCR 20~~17

Re: <u>Coal Combustion Residuals Legal Resources Group</u>

Retainer for services in connection with the
Coal Combustion Residuals Legal Resources Group for 2017 .... $70,000

PLEASE REMIT PAYMENT BY JANUARY 20, 2017 USE ONE OF THE BELOW METHODS OF PAYMENT

Check Via First-Class Mail

Hunton & Williams LLP
Attention: Kathy Robinson
2200 Pennsylvania Avenue, NW
Washington, DC 20037
Reference – 2017 CCR Annual Dues/86837.2

Wiring Instructions

Bank:
Account Name:

Account No.
ABA Transit Routing No
Information with wire
Swift Code (Internat'l)

[redacted]

LGE - $26,600
KU - $43,400

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA, SUITE 3500
101 SOUTH TRYON STREET
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: nlong@hunton.com

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: brosser@hunton.com

FILE NO: 54675.000002

December 14, 2017

Confidential
Attorney-Client Privilege

Robert J. Ehrler, Esq.
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40232

Re: **NSR Legal Resources Group**

Retainer for services in connection with the
NSR Legal Resources Group for 2018 ....$35,000

PLEASE REMIT PAYMENT BY JANUARY 20, 2018 USE ONE OF THE BELOW METHODS OF PAYMENT

Check Via First-Class Mail

Hunton & Williams LLP
Attention: Kathy Robinson
2200 Pennsylvania Avenue, NW
Washington, DC 20037
Reference – 2018 NSR Annual Dues/54675.2

Wiring Instructions

Bank: [redacted]
Account Name:

Account No.
ABA Transit Routing No
Information with wire
Swift Code (Internat'l)

LGE – $ 12,250
KU – $ 22,750

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA, SUITE 3500
101 SOUTH TRYON STREET
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: nlong@hunton.com

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: brosser@hunton.com

FILE NO: 54675.000002

December 16, 2016

Inv. No.
~~NSR 2017~~

Confidential
Attorney-Client Privilege

Robert J. Ehrler, Esq.
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40232

Re: NSR Legal Resources Group

Retainer for services in connection with the
NSR Legal Resources Group for 2017 .... $35,000

PLEASE REMIT PAYMENT BY JANUARY 20, 2017
USE ONE OF THE BELOW METHODS OF PAYMENT

Check Via First-Class Mail

Hunton & Williams LLP
Attention: Kathy Robinson
2200 Pennsylvania Avenue, NW
Washington, DC 20037
Reference -- 2017 NSR Annual Dues/54675.2

Wiring Instructions

Bank:
Account Name:

Account No.
ABA Transit Routing No.
Information with wire
Swift Code (Internat'l)
[redacted]

LGE - $12,250
KU - $22,750

North American Transmission FORUM

North American Transmission Forum, Inc.
9300 Harris Corners Parkway
Suite 300
Charlotte, NC 28269
(704) 945-1900
taldred@natf.net
http://www.natf.net

INVOICE

BILL TO
LGE & KU Energy, LLC
220 W. Main Street
Louisville, KY 40202

INVOICE # 1702
DATE 10/06/2017
DUE DATE 01/31/2018
TERMS Net 30

ACTIVITY	AMOUNT
Membership Equal Share 2018	22,000.00
Load Ratio Share Load Ratio Share 2018	51,165.00

BALANCE DUE **$73,165.00**

Project 141057 Task I-COMPANYDUES
Exp Org 023000 Exp Type 0650
Amount Approved 73,165.00
Date Approved
Approved by

Chr Bel
2/8/18

LGE - 25,607.75
KU - 47,557.25

V# 70727

North American Transmission FORUM

North American Transmission Forum, Inc.
9300 Harris Corners Parkway
Suite 300
Charlotte, NC 28269
(704) 945-1900
taldred@natf.net
http://www.natf.net

INVOICE

BILL TO
LGE & KU Energy, LLC
220 W. Main Street
Louisville, KY 40202

INVOICE # 1605
DATE 10/03/2016
DUE DATE 12/31/2016
TERMS Net 30

DATE	ACCOUNT SUMMARY	AMOUNT
11/09/2015	Balance Forward	$55,401.00
	Payments and credits between 11/09/2015 and 10/03/2016	-55,401.00
	New charges (details below)	61,829.00
	Total Amount Due	$61,829.00

ACTIVITY	AMOUNT
Membership Equal Share 2017	22,000.00
Load Ratio Share Load Ratio Share 2017	39,829.00

TOTAL OF NEW CHARGES	61,829.00
BALANCE DUE	**$61,829.00**

Invoices are dated with a 12/31/2016 due date. You can pay in 2016 or no later than 1/31/2017. Contact Teresa Aldred @ 704-945-1923 if you need anything changed to process. Email copy was sent on 10/3/16 to Member Reps

LGE - $ 21,621.86
KU - $ 40,867.14

RECEIVED
OCT 06 2016
ACCOUNTS PAYABLE

MIDWEST OZONE GROUP

MEMBERSHIP INVOICE

November 27, 2017

LG&E / KU
Attention: Robert Ehrler
220 West Main Street
Louisville, KY 40202

2018 Assessment based upon 1.25 share,
due on or before March 31, 2018

$68,750.00 Current Dues

LGE - $24,062.50
KU - $44,687.50

Please make payment to: Steptoe & Johnson, PLLC
Agent for MOG
c/o David M. Flannery
Post Office Box 1588
Charleston, West Virginia 25326

MIDWEST OZONE GROUP

MEMBERSHIP INVOICE

November 4, 2016

Inv. No.
~~[illegible]~~

LG&E / KU
Attention: Robert Ehrler
220 West Main Street
Louisville, KY 40202

2017 Assessment based upon 1.25 share,
due on or before March 31, 2017

$68,750.00 Current Dues

LGE - $ 24,062.50
KU - $ 44,687.50

Please make payment to: Steptoe & Johnson, PLLC
Agent for MOG
c/o David M. Flannery
Post Office Box 1588
Charleston, West Virginia 25326

UNIVERSITY OF LOUISVILLE RESEARCH FOUNDATION
SPONSORED PROGRAMS FINANCIAL ADMINISTRATION
INVOICE

UNIVERSITY OF LOUISVILLE.

Invoice Detail:

Invoice ID:	LG&E INV2018-001
Invoice Date:	2018-02-21
Payment Terms:	IMMED

Bill To:
Jessi J. Logsdon
Sourcing Leader, Corporate Purchasing
LG&E and KU Services Company
820 E. Broadway
Louisville, KY 40202

Project Detail:

UofL Ref:	OGMB160808P
PI:	Prater, Glen
Project:	Industry/University Cooperative Research Center for Efficient Vehicles and Sustainable transportation Systems (EV-STS) NSF EV-STS I/U CRC

Current Amount Due: **$50,000.00**

Invoiced Items:

FY 2018-2019 EV-STS Membership Dues Currently Payable: **$50,000.00**

With payment of this invoice, LG&E and KU Services Company will have an EV-STS Membership through 06/30/2019. EV-STS Membership Agreement signed by Stephanie R. Pryer on 04/20/17 (Sponsorship Effective 07/01/17).

Please make payment in **US Dollars**, and include a copy of this invoice with payment.
Remit To: University of Louisville Research Foundation, Inc.
Office of Sponsored Programs Administration

Attention: Andrea Welch
300 East Market Street, Suite 300
Louisville, KY 40202-1959

LGE - $19,000
KU - $31,000

Andrea Welch
Andrea Welch
Grant Management Accountant

CPA# PO#

Project	Task	Exp Type	$$ or % Split
SRC153955	UNIVERSITY	0650	100%

Proponent (up to $1k) Date 2/22/18
~~Group/ Team Leader (up to $10k)~~ ~~Date~~
Manager (up to $100k) Date 2/26/18

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. Gary H. Revlett
Director, Environmental Affairs
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Invoice

Invoice # : 209242
Invoice Date: 12/13/2017
FEIN: 13-0659550

Description	Quantity	Price	Discount	Amount
2018 UARG Membership Dues - Mr. Gary H. Revlett	1	$281,841.00	$0.00	$281,841.00

This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the calendar year 2018. If you have questions about the program, please contact Andrea Field at 202-955-1558. If you have questions regarding this invoice or to make payment arrangements, please contact Carol Scates, in EEI's Internal Accounting Department, at 202-508-5428.

Invoice Total	$281,841.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$281,841.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice1 #: 209242

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

LGE - $109,917.99
KU - $171,923.01

Payment Method

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. Gary H. Revlett
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Invoice

Invoice # : 192522
Invoice Date: 12/01/2016
FEIN: 13-0659550

Description	Quantity	Price	Discount	Amount
2017 UARG Membership Dues – **ACTUAL DUES AMOUNT**	1	$268,376.00	$0.00	$268,376.00

LGE - $ 101,982.88
KU - $ 166,393.12

This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the calendar year 2017. If you have questions about the program, please contact Andrea Field at 202-955-1558. If you have questions regarding this invoice or to make payment arrangements, please contact Carol Ray, in EEI's Internal Accounting Department, at 202-508-5428.

Invoice Total	$268,376.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	**$268,376.00**

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 192522

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Payment Method

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804-788-8200
FAX 804-788-8218

Invoice #102128134
November 29, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through October 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	78.22
Legal Fees and Expenses	$	8,799.77
Credit	$	0
TOTAL DUE	**$**	**8,877.99**

LGE - $3,462.42
KU - $5,415.57

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102129784
December 19, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through November 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	8,391.66
Credit	$	0
TOTAL DUE	**$**	**8,391.66**

LGE - $ 3,272.75
KU - $ 5,118.91

EIVED
06 2018
PAYABLE

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102131210
January 26, 2018
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through December 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	882.82
Legal Fees and Expenses	$	8,612.29
Credit	$	()
TOTAL DUE	**$**	**9,495.11**

LGE - $3,703.09
KU - $5,792.02

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

Invoice #102132441
February 21, 2018
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through January 2018 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	
Legal Fees and Expenses	$	8,105.17
Credit	$	0
TOTAL DUE	**$**	**8,105.17**

LGE - $3,161.02
KU - $4,944.15

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102134496
March 16, 2018
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through February 2018 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	
Legal Fees and Expenses	$	8,695.21
Credit	$	0
TOTAL DUE	**$**	**8,695.21**

LGE - $ 3,391.13
KU - $ 5,304.08

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

Invoice #102108220B
August 25, 2016
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through July 2016 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	82.53
Legal Fees and Expenses	$	9,591.19
Total Due	$	9,673.72
Amount Paid	$	(7,255.29)
BALANCE DUE	**$**	**2,418.43**

LGE - 894.82
KU - 1,523.61

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

Invoice #102113260
December 15, 2016
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through November 2016 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	122.17
Legal Fees and Expenses	$	6,609.67
Credit	$	0
TOTAL DUE	$	**6,731.84**

LGE - 2,558.10
KU - 4,173.74

RECEIVED
JAN 2 0 2017
ACCOUNTS PAYABLE

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102114903
January 31, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through December 2016 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	123.02
Legal Fees and Expenses	$	19,119.79
Credit	$	0
TOTAL DUE	**$**	**19,242.81**

ACCOUNTS PAYABLE
FEB 07 2017
RECEIVED

LGE - 7,119.84
KU - 12,122.97

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102116294
February 28, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through January 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	7,413.77
Credit	$	0
TOTAL DUE	**$**	**7,413.77**

LGE - 2,743.09
KU - 4,670.68

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102116911
March 16, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through February 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	9,109.63
Credit	$	0
TOTAL DUE	**$**	**9,109.63**

LGE - 3,370.56
KU - 5,739.07

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102118542
April 25, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through March 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	7,196.26
Credit	$	0
TOTAL DUE	**$**	**7,196.26**

LGE - 2,662.62
KU - 4,533.64

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102119593
May 22, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through April 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	10,258.59
Credit	$	0
TOTAL DUE	**$**	**10,258.59**

LGE - 3,898.26
KU - 6,360.33

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102121047
June 26, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through May 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	193.86
Legal Fees and Expenses	$	8,899.94
Credit	$	0
TOTAL DUE	**$**	**9,093.80**

LGE - 3,455.64
KU - 5,638.16

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102122602
July 28, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through June 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	8,288.56
Credit from May Invoice	$	(124.47)
TOTAL DUE	**$**	**8,164.09**

LGE - 3,162.35
KU - 5,001.74

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102124457
August 30, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through July 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	9,698.13
Credit	$	()
TOTAL DUE	**$**	**9,698.13**

LGE - 3,782.27
KU - 5,915.86

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102125945
October 2, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through August 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	11,016.42
Credit	$	()
TOTAL DUE	**$**	**11,016.42**

LGE - 4,296.40
KU - 6,720.02

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102127227
October 26, 2017
29142.050001

Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through September 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

Consultant Charges	$	0.00
Legal Fees and Expenses	$	10,791.88
Credit	$	0
TOTAL DUE	**$**	**10,791.88**

LGE - 4,208.83
KU - 6,583.05

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. William Paul Puckett
Sr. Environmental Engineer
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Invoice

Invoice # : 210212
Invoice Date: 01/16/2018
[redacted]

Description	Quantity	Price	Discount	Amount
2018 USWAG Membership Dues - Mr. William Paul Puckett	1	$68,175.00	$0.00	$68,175.00

RECEIVED
JAN 26 2018
ACCOUNTS PAYABLE

This invoice is for the 2018 Utility Solid Waste Activities Group (USWAG) Membership Dues. The portion of 2018 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes is estimated to be 3%. If you have questions concerning the USWAG program, please contact Jim Roewer, at 202-508-5645. If you have questions regarding payment for this invoice, please contact Carol Scates, in EEI's Internal Accounting Department, at 202-508-5428.

Invoice Total	$68,175.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	$68,175.00

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice1 #: 210212

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

LGE - # 26,588.25
KU - # 41,586.75

Payment Method

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. W. Michael Winkler
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Invoice

Invoice # : 194276
Invoice Date: 01/25/2017
[redacted]

Description	Quantity	Price	Discount	Amount
2017 USWAG Membership Dues	1	$67,500.00	$0.00	$67,500.00

This invoice is for the 2017 Utility Solid Waste Activities Group (USWAG) Membership Dues. The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes is estimated to be 3%. If you have questions concerning the USWAG program, please contact Gayle Novak, at 202-508-5654. If you have questions regarding payment for this invoice, please contact Carol Ray, in EEI's Internal Accounting Department, at 202-508-5428.

Invoice Total	$67,500.00
Taxes	$0.00
Amount Paid	$0.00
PLEASE PAY	$67,500.00

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 194276

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Payment Method

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

LGE - $21,600

KU - $45,900

ACAA 2018 Membership Dues Invoice

ACAA

Make payment to "ACAA" - 38800 Country Club Drive, Farmington Hills, MI 48331 – Phone: (720) 870-7897

RECEIVED
OCT 16 2017

Member Primary Point of Contact:

LG&E and KU Services Company
Kenneth Tapp
By-Products Coordinator
220 West Main Street, 4th Floor
Louisville KY 40202

Phone: (502) 627-3154

Email: kenny.tapp@lge-ku.com

RECEIVED
OCT 16 2017
By [signature]

Billing Contact (If other than Primary POC):

Billing POC:

Invoice Date: 11/1/2017	Processing Rep: ajb	ACAA Tax ID: [redacted]	Invoice Number: lg&e2018
Invoice Detail:			
Unadjusted Dues:	$15,000.00	Dues For:	Utility 2018 Category U Member Dues
Discount (If Applied)	0.00%	Terms:	On Receipt
Total Due:	$15,000.00	Invoice Comments:	
Paid To Date:	$0.00		
Balance Remaining:	$15,000.00	DatePaid (ACAA Use Only)	

Thank you for your continuing support of ACAA and the CCP Industry!

LGE - 7,200
KU - 7,800

ACAA Educational Foundation

Members are encouraged to consider making a tax deductible donation to the ACAA Educational Foundation (501(c)(3)). The Foundation promotes the sponsorship of educational conferences and scholarships and support of educational and scientific publications and activities related to the beneficial use of coal combustion products.

Donations to the Foundation should be made out to: "ACAA Educational Foundation" and mailed to the ACAA office.

Donation Amount: ____________________

A receipt for your donation will be sent to your organization's primary point of contact addressed above unless you request otherwise.

Advancing the management and use of coal combustion products.

ACAA **American Coal Ash Association**

October 2017

To All ACAA Members:

It is time to renew your membership in the American Coal Ash Association. We thank you for your support in 2017 and ask for your continued support in 2018. As you consider your investment in the mission of the ACAA we ask you to consider the following facts.

- The markets for beneficial use of coal combustion products (CCP) continue to improve. The most recent data available indicates strong recovery in some markets from the regulatory threat from the U.S. Environmental Protection Agency (EPA). In total, beneficial use is now over 50%. At the beginning of this century the beneficial use rate was just over 29%. The progress is real and substantial.
- As the use of coal as a fuel for generating electricity stabilizes in the 30% to 35% range, availability of CCP is stabilizing as well. Investment in the infrastructure needed to meet market demand is beginning to make a difference. Some increased activity in CCP imports has been noted. Increased interest in reclaiming CCP from surface impoundments and landfills has the potential to meeting the growing demand for CCP. The ACAA has been working hard to inform user groups as to the future availability of the materials that have proven to be so important to our economy.
- With a new administration taking over the federal government in 2017, the ACAA has been actively involved with new management at the EPA to unwind some of the actions of previous management that have been so damaging to our members. Great progress has been made. We are committed to building on this momentum in 2018.
- The 2017 World of Coal Ash was a record-setting event by any standard. Attendance and technical content was well beyond previous records. The strength of this event speaks to the importance and interest in our industry.

In 2018 the ACAA will mark its 50th anniversary. Incorporated in Washington, D.C. on March 8, 1968 as the National Ash Association, the ACAA has served as the voice for the beneficial use industry helping to divert hundreds of millions of tons of CCP from disposal units to uses that are *environmentally responsible, technically appropriate, commercially competitive, and supportive of a more sustainable society.* Our mission remains unchanged and is more important than ever.

We hope you will elect to renew your ACAA membership and help us to continue to advance our mission.

Sincerely,

Thomas H Adams

Thomas H. Adams, Executive Director

38800 Country Club Drive, Farmington Hills, Michigan 48331-3439
Office: 720-870-7897 Fax: 720-870-7889 Email: info@ACAA-USA.org Website: http://www.ACAA-USA.org

September 13, 2017

Carbon Utilization Research Council

1050 Thomas Jefferson Street, NW; Suite 700; Washington, DC 20007

INVOICE

Ms. Caryl Pfeiffer
Director, Corporate Fuels & By-Products
LG&E and KU
220 West Main Street
P.O. Box 32030
Louisville, KY 40202

Enclosed are 2018 membership dues to the Carbon Utilization Research Council in the amount of:

- 2018 Full Council Membership — $30,000

<15,000>

15,000

Please make check payable to:
Carbon Utilization Research Council

And remit to:

LGE - $7,200

Judy Bernstein
Carbon Utilization Research Council
1050 Thomas Jefferson Street, NW, Suite 700
Washington, DC 20007-3877

KU - $7,800

Notification Regarding Nondeductibility of the Portion of Dues Payment Allocable to Lobbying Activities

The Reconciliation Act that was enacted in 1993 eliminated the deduction for lobbying expenses previously available to certain taxpayers under section 162(e) of the Internal Revenue Code, effective for expenses incurred after December 31, 1993. A portion of 2018 dues of the Carbon Utilization Research Council will be allocable to lobbying activities carried on by the council, and therefore will be nondeductible. **For 2018, the percentage of each dues payment estimated to be allocable to lobbying expenditures is 50 percent.**

CORE MEMBERSHIP RENEWAL FORM

Utilities Technology Council™

Current Expiration Date: 9/30/2017

LG&E and KU Services Company
John Pulliam, Telecom Engineer
820 W Broadway,
Louisville, KY 40202-2218

Membership Renewal Notice
UTC's 2018 membership year runs from October 1, 2017 through December 31, 2018. UTC membership fees are based on total gross annual revenues from the most recent fiscal year. Calculate your annual fee based on the table shown below.

ANNUAL REVENUE	MEMBERSHIP DUES
Revenue < $15	$625
$15< ≤ Revenue ≤ $25M	$938
$25M ≤ Revenue ≤ $50M	$1,875
$50M < Revenue ≤ $100M	$3,125
$100M < Revenue ≤ $250M	$4,688
$250M < Revenue ≤ $500M	$6,250
$500M < Revenue ≤ $750M	$9,375
$750M < Revenue ≤ $1.25B	$12,500
$1.25B < Revenue ≤ $5B	$18,750
$5B < Revenue ≤ $10B	$25,000
Revenue > $10B	$37,500

Please note: *Dues are calculated for 15 months of membership for 2018 only. Contributions or gifts to UTC are not deductible as charitable contributions for Federal income tax purposes. However, they may be tax deductible as ordinary and necessary business expenses. For these purposes, UTC estimates that 5% of your membership fee will be allocable to nondeductible lobbying activities during the ensuing fiscal year.* **UTC offers three effortless ways to renew your organization's membership in the association.**

BY MAIL: UTC Membership
P.O. Box 79358
Baltimore, MD 21279-0358 USA

[redacted]

Please detach lower portion and remit with payment.

Utilities Technology Council™

Core Membership Renewal: 2017-2018

15 month Dues Calculation:
12 months (*15000*) + 3 months (*3750*) = Amount Due: $ 18750

LGE - 9,750
KU - 9,000

Amount Enclosed = $________

If paying by credit card, please indicate card type: ☐ **Visa** ☐ **MasterCard** ☐ **American Express**

Cardholder's Name | Card Number | Expiration Date

Billing Address | City/State | Zip/Postal Code | Cardholder's Signature

PLEASE SEND A COPY OF THE INVOICE W ITH YOUR PAYMENT

PLEASE MAKE CORRECTIONS TO PRIMARY CONTACT NFORMATION BELOW IF NECESSARY.

Name John Pulliam **Title** Telecom Engineer

Company LG&E and KU Services Company

Address 820 W Broadway Louisville, KY 40202-2218

Phone: **E-mail Address** john.pulliam@lge-ku.com

Questions? Please contact Tiffany Bennett, Membership Manager, at 1.202.833.6822 or tiffany.bennett@utc.org

Pd. by phone w corp card Tues 12/13/16

SGA Linking People, Ideas, Information

Invoice Number	Invoice Description	Invoice Date	Invoice Due Date	Order Number	PO#
684521	Southern Gas Association - Distribution SGA Gas Member (10/01/2016-09/30/2017)	09/15/2016	10/01/2016	440695	

Bill To: 220
LG&E and KU Energy LLC
220 W. Main Street
Louisville, KY 40202

Ship To: 220
LG&E and KU Energy LLC
220 W. Main Street
Louisville, KY 40202

Date	Description	Type	Quantity	Rate	Tax	Tax Rate	Amount
09/15/2016	SGA Distribution Membership	INVLINE	1				17,400.00
12/13/2016	Payment	PAYMENT					-17,400.00
						Total Invoice:	17,400.00
						Total Payment:	-17,400.00
						Balance:	0.00

Southern Gas Association
3030 LBJ Freeway, Suite 1500, Dallas, TX 75234
***Phone:** 972-620-8505 **Fax:** 972-620-1613*
***Email:** memberservices@southerngas.org*

Kentucky Gas Association
2896 Butterworth Road
P.O. Box 29
Murray, KY 42071

Phone # 800.455.9427 n.morton@kygas.org
Fax # 270.489.0061 www.kygas.org

Sales Receipt

[illegible]	[illegible]
9/6/2017	1181

[illegible]
Barry R Walker Louisville Gas & Electric Company 820 West Broadway Louisville, KY 40202

[illegible]	Payment Method	[illegible]
	Visa	

Description	[illegible]	Rate	Amount
Distribution Corporate Membership Dues Renewal for Fiscal Year 2017 - 2018 for Louisville Gas & Electric Company (Barry R. Walker)		10,000.00	10,000.00
		Total	$10,000.00

2017

SGA *Linking People, Ideas, Information*

Invoice Number	Invoice Description	Invoice Date	Invoice Due Date	Order Number	PO#
690809	Southern Gas Association (10/01/2017-09/30/2018)	09/27/2017	10/01/2017	443876	

Bill To: 220
LG&E and KU Energy LLC
220 W. Main Street
Louisville, KY 40202

Ship To: 220
LG&E and KU Energy LLC
220 W. Main Street
Louisville, KY 40202

Date	Description	Quantity	Rate	Tax	Tax Rate	Amount
09/27/2017	SGA Distribution Membership	1				17,400.00
10/03/2017	Payment					-17,400.00
					Total Invoice:	17,400.00
					Total Payment:	-17,400.00
					Balance:	0.00

Southern Gas Association
3030 LBJ Freeway, Suite 1500, Dallas, TX 75234
Phone: 972-620-8505 Fax: 972-620-1613
Email: memberservices@southerngas.org

F   ED

MAR 07 2018

AC   S YABLE

FRI
FINANCIAL RESEARCH INSTITUTE

University of Missouri-Columbia
Phone: 573-882-3800

ENTERED

March 1, 2018

Invoice Number: 18-1018

Robert Conroy
Vice President, State Regulation & Rates
LG&E & KU Energy
220 West Main Street
Louisville, KY 40202

Project:	SRV21440
Task:	DUES COMPANY
Expense Type:	0650
Expense Org:	021440
Signature	[signature]
Approval Signature	[signature]
Approval Date	3/5/18

Financial Research Institute / Public Utility Division Advisory Board Appointment	
Appointment Term	**Amount Due**
May 1, 2018 – April 30, 2019	**$10,000.00**

Please make your check payable to: **University of Missouri-FRI/PUD**

The University of Missouri/FRI's tax identification number is [redacted]

LGE - $4,500 (under $5M)
KU - $5,500

Mail payment to: Financial Research Institute/Public Utility Division
Trulaske College of Business
401A Cornell Hall
Columbia, MO 65211

PLEASE REMIT PAYMENT ON OR BEFORE APRIL 15, 2018

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 99

Responding Witness: Christopher M. Garrett

Q-99. Provide any and all documents in the Companies' possession that depict how each Dues Requiring Organization spends the dues it collects, including the percentage that applies to all covered activities.

A-99. See the responses to Question Nos. 94 and 98.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 100

Responding Witness: Christopher M. Garrett

Q-100. Provide a detailed description of the services each Dues Requiring Organization provided to the Company since the conclusion of the Company's last rate case. Of these services or benefits, state which benefits accrue to ratepayers, and how.

A-100. Company employees participate in various industry associations and organizations as presented in FR 16(8)(f), Sch. F-1 to gain knowledge, training, timely information and experience throughout the industry to allow for the Company to provide service to its customers in the most economical, cost effective, safe and reliable manner. The gaining of industry knowledge through these associations benefits customers through the use of best practices in providing services.

<u>Edison Electric Institute (EEI):</u> The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

<u>Electric Power Research Institute (EPRI):</u> EPRI is a non-profit research consortium providing science and technology solutions for the benefit of utility members, their customers, and society. Funding annual Technology Research and Analysis activities is an expected and prudent activity recognized by the Kentucky Public Service Commission. EPRI has organized and provided this activity for member utilities since its founding in 1973. EPRI provides a collaborative research model that provides LG&E and KU leverage on their investment of approximately 20:1. Cutting edge research keeps LG&E and KU aware of significant technology changes and applications to improve operations.

<u>Coal Combustion Residuals (CCR) Legal Resources Group and New Source Review (NSR) Legal Resources Group</u>: This is a group of utilities which have retained common counsel that monitor developments and assess potential liability in the areas of coal combustion residuals and new source review.

<u>Midwest Ozone Group (MOG) and Steptoe & Johnson LLC (agent of MOG):</u> The Midwest Ozone Group (MOG) is an affiliation of companies, trade organizations,

and associations which have drawn upon their collective resources to advance the objective of seeking solutions to the development of a legally and technically sound national ambient air quality program. It is the primary goal of MOG to work with policy makers in evaluating air quality policies by encouraging the use of sound science. As members of the business community, the MOG membership also has a keen interest in assuring that policy makers are appropriately assessing the data and information required to accurately evaluate its emission control strategies.

Utility Air Regulatory Group (UARG): UARG is a not-for-profit association of individual electric generating companies and national trade associations. UARG participates on behalf of its members collectively in Clean Air Act ("CAA") administrative proceedings that affect electric generators and in litigation arising from those proceedings.

Class of 85 represented by Baker Botts LLP: This group participates on behalf of its members collectively in Clean Air Act ("CAA") administrative proceedings that affect electric generators and in litigation arising from those proceedings

Utility Water Act Group (UWAG): UWAG is a voluntary, non-profit, unincorporated group of 147 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the Clean Water Act and in litigation arising from those rulemakings.

Utility Solid Waste Activities Group (USWAG): USWAG is responsible for addressing solid and hazardous waste issues on behalf of the utility industry. USWAG was formed in 1978, and is a trade association of over 110 utility operating companies, energy companies and industry associations, including the Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the American Public Power Association (APPA), and the American Gas Association (AGA). USWAG engages in regulatory advocacy pertaining to RCRA, TSCA, and HMTA. USWAG's mission is to address the regulation of utility wastes, byproducts and materials in a manner that protects human health and the environment and is consistent with the business needs of its members.

North American Transmission Forum (NATF) services include:

- Peer Reviews: NATF peer reviews help members improve operations. Review teams comprise subject matter experts from other utility members and staff that review selected practice areas and cross-functional topics at the utility hosting the review. The teams' final reports include noteworthy positives that are shared with other members and improvement recommendations for the host utility to implement.

- Assistance: Assistance is tailored to a particular member's request or needs by leveraging one or more NATF programs or offerings. NATF subject-matter experts and staff work with host companies to help them develop action plans to improve on selected topics or issues.
- Practices: Groups of subject-matter experts hold monthly web meetings and annual workshops, and write NATF practices and principles of excellence. Groups include: • Compliance • Equipment Performance & Maintenance • Human Performance Improvement • Modeling and Planning • Operator Training • Cyber Security • Physical Security • System Operations • System Protection • Vegetation Management
- Reliability Initiatives: The NATF coordinates activities related to select established or emerging reliability topics in a project based format. Currently there are initiatives on resilience, supply chain risk management, and human performance near-miss database.
- Knowledge Management: The NATF supports the exchange and management of operating experience and reliability data. Secure, effective program tools (databases, scorecards, performance reports, surveys, lessons learned summaries, and operating experience library) and regular working group meetings help facilitate internal peer benchmarking, dissemination of objective performance information, and awareness of key reliability trends and risks.
- Training: The NATF offers web-based resources on select topics chosen and prioritized by members.

<u>American Gas Association ("AGA")</u> services include:

Communications develops informational material for member companies and consumers and coordinates media activity. Educates the public on the safety and benefits of natural gas.

Corporate Affairs provides opportunities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

Energy Markets, Analysis, and Standards includes:

1. Energy Markets provides insight and analysis on emerging policies and actions that have the potential of impacting natural gas distribution companies and their customers.
2. Energy Analysis provides analytical support to key areas of focus including natural gas market fundamentals, local gas utility operations and financial

performance, general industry data, critical gas supply/demand developments, winter heating season planning, energy efficiency, greenhouse gas emissions, and other environmental issues.

3. Standards support the development of building energy codes and standards that help enhance natural gas safety.

General and Administrative includes:

1. Office of the President provides senior management guidance for all AGA activities.
2. Human Resources develops and administers employee programs and provides office and personnel services.
3. Finance and Administration develops and administers financial accounting and treasury services and maintains computer services capability.

General Counsel and Regulatory Affairs includes:

1. General Counsel provides legal counsel to the Association.
2. Regulatory Affairs provides members with information on FERC and regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

Government Affairs and Public Policy provides members with information on legislative developments; prepares testimony, comments, and filings regarding legislative activities, lobbies on behalf of the industry and its customers to achieve the Association's advocacy priorities.

Industry Finance and Administration develops and implements programs in such areas as accounting, human resources, and risk management for member companies.

Operations and Engineering develops and implements programs and practices to meet the operational, safety, and engineering needs of the industry.

<u>University of Louisville Research Foundation Inc.</u>: LG&E and KU Technology Research and Analysis utilizes the research conducted by Efficient Vehicles and Sustainable transportation Systems (EV-STS) to better understand future electric vehicle technologies and needs for supporting Electric Vehicles (EV) charging infrastructure.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 101

Responding Witness: Christopher M. Garrett

Q-101. Provide a list of all presentations, webinar recordings, briefing books, policy memos, and white papers that each Dues Requiring Organization provided to the Companies since the conclusion of their last rate cases.

A-101. The Company objects to this question because it is overly broad and unduly burdensome. Many employees participate in Organization Memberships as presented in FR 16(8)(f), Sch. F. Many of these employees receive almost daily email communications from the organizations. Creating a list of all materials that each of the Organization Memberships provided to the Companies would be unduly burdensome and require an electronic search of emails and electronic files of many custodians, resulting in significant expense.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 102

Responding Witness: Christopher M. Garrett

Q-102. Has the Company included in operating expenses any amount for: (i) EEI Media Communications, and (ii) any similar division of any other Dues Requiring Organization?

a. If so, state the amount, indicate in which account this has been recorded, and provide a citation to any and all Commission Orders or other authority upon which the Company relies for the inclusion of such expense in the test period.

b. If not, provide an estimate of how much of the Company's dues are being spent on media or public relations work.

A-102. As stated in the response to Question No. 92, the Company has excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 103

Responding Witness: Christopher M. Garrett

Q-103. State whether the Company is aware whether any portion of the dues it pays to any Dues Requiring Organization are utilized to pay for any of the following expenditures, and if so, provide complete details:

a. Influencing federal or Kentucky legislation;

b. Any media advertising campaigns backing the Companies' or the Dues Requiring Organization's position on net metering;

c. Expenditures on "We Stand For Energy," or "Defend My Dividend," public relations, advocacy efforts or other covered activities;

d. Contributions from EEI, EPRI or other Dues Requiring Organizations to third-party organizations and contractors including any of the expenditures identified in a. – c., above.

A-103. The Company has excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI. EPRI does not engage in any covered activities.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 104

Responding Witness: Robert M. Conroy

Q-104. Since the conclusion of the Company's last rate case, how much has EEI paid for its efforts to "rebrand" the utility industry? Include in your response payments to external public relations firms as well as the associated salary to any EEI staff involved in contracting, coordinating with, or promulgating internally or externally the rebranding campaign effort.[10]

A-104. LG&E does not collect and retain the requested information for its corporate files. See the response to Question No. 98.

[10] See, e.g., https://www.huffingtonpost.com/entry/messaging-utilities-solar power_us_56f45cd6e4b014d3fe22b572

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 105

Responding Witness: Robert M. Conroy

Q-105. Do the Company's EEI dues contribute to the salary, benefits and expenses of the EEI Executive Vice President for Public Policy and External Affairs, or any other EEI officer or employee who has led an effort EEI undertook to rebrand the utility industry?

A-105. LG&E does not collect and retain the requested information for its corporate files. See the response to Question No. 98.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 106

Responding Witness: Daniel K. Arbough

Q-106. List all travel and entertainment expenses that Company employees incurred in the base period and are included in the forecast period, or that are expected to be incurred and included in the forecast period, in relation to Dues Requiring Organization activities. Show accounts, amounts, descriptions, person, job title and reason for the expense. Provide a copy of applicable employee time and expense reports and invoices documenting such expenses.

A-106. In general the request seeks information that the Company does not identify and retain in the categories requested. Travel expenses are not organized according to attendance at seminars and training events held by the various professional organizations. The request requires a significant amount of original work and cannot be completed within the time provided for the response. Entertainment expenses are typically not reimbursable and if so are booked below the line.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 107

Responding Witness: Christopher M. Garrett

Q-107. Is the Company relying upon any NARUC reports or other studies for the exclusion from or inclusion in rates of a portion of its dues payable to EEI, or to any other Dues Requiring Organization? If so, please provide a copy of such report and indicate how the report's recommendations have been included in its filing.

A-107. See the response to Question No. 91.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 108

Responding Witness: Christopher M. Garrett

Q-108. Do any of the Company's personnel actively participate on Committees and/or perform any other work for any Dues Requiring Organization or any other industry organization to which the Company belongs, including but not limited to EEI?

a. If so, state specifically which employees participate, how they are compensated for their time (amount and source of compensation), and the purpose and accomplishments of any such association related work.

b. List any and all reimbursements received from industry associations, for work performed for such organizations by Company employees.

A-108. Company employees participate in various industry associations and organizations to gain knowledge, training, timely information and experience throughout the industry to allow for the Company to provide service to its customers in the most economical, cost effective, safe and reliable manner. The gaining of industry knowledge through these associations benefits customers through the use of best practices in providing services.

a. With one limited exception relating to contractual work for EPRI, employees are not compensated by industry organizations for participation on committees. See the response part b.

b. With regard to the EPRI work referenced in part a. above, since 2016, the Company has been reimbursed by EPRI for work paid to three regular, full-time employees beyond their normal compensation. Reimbursement from EPRI was also received for work paid to a temporary employee.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 109

Responding Witness: Christopher M. Garrett

Q-109. State whether any portion of LG&E's dues paid to the American Gas Association ("AGA") are used by the AGA for any of the following:

a. public affairs and/or lobbying;

b. media communications and national advertising;

c. institutional advertising to enhance the image of the gas industry;

d. general promotional advertising to promote the use of natural gas over other resources;

e. gas-fired equipment promotions, including residential equipment such as furnaces, ranges, water heaters, and commercial and industrial gas equipment;

f. promotions of power generation gas equipment.

A-109. See the response to Question No. 95 for the breakout of operating expenses provided by AGA.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 110

Responding Witness: Gregory J. Meiman

F. <u>Compensation</u>

Q-110. Refer to the direct testimony of Lonnie E. Bellar, page 27, wherein he discusses the starting pay for the Companies' Customer Representatives.

b. Under what category of employees (i.e. hourly, exempt, salary, etc.) do Customer Representatives fall under in reference to wages in rate case applications?

A-110. Customer Representatives fall under the non-exempt category.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 111

Responding Witness: Daniel K. Arbough

Q-111. Refer to the direct testimony of Lonnie E. Bellar, page 28, wherein he discusses the hourly wage increases for Customers Representatives.

a. Where is this adjustment located in the application?

A-111.

a. The effect of the hourly wage increases is included within account numbers 901 (Customer Accts Supervision) and 903 (Customer Records and Collection Expenses), from the Schedule D-1, page 6 of 9, lines 105 and 107.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018

Case No. 2018-00295

Question No. 112

Responding Witness: Gregory J. Meiman

Q-112. Regarding findings of the Willis Towers Watson ("WTW") Target Total Cash Compensation Study, the direct testimony of Gregory J. Meiman, page 10, states, "The Companies' use of base salary and target incentive compensation as its primary pay vehicles for employees is consistent and aligned with market pay vehicles used by utility and general industry peers."

a. Identify the list of utility peers used in the comparison.

b. Identify the criteria for the "utility peers" that WTW used to qualify them as peers for the study's comparative purposes.

A-112.

a. The attached files contain participant lists of the four utility industry focused compensation surveys used in completing the benchmarking study for KU and LG&E. Attachment 1 contains two WTW Energy Services compensation survey participant lists. Attachments 2 and 3 contain two compensation survey participant lists being filed pursuant to a Petition for Confidential Protection.

b. The selection criteria used in leveraging these surveys for completing the compensation benchmarking analysis are as follows:

- Readily available, published compensation surveys covering utility/energy services benchmark positions similar to KU/LGE positions
- Compensation surveys predominantly focused on regulated utilities and the national US market that cover all major components of compensation

Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

2017 Willis Towers Watson CDB Energy Services Executive Compensation Survey

Participant List

AES Corporation
ALLETE
Alliant Energy
Ameren
American Electric Power
Aqua America
Areva
AREVA Nuclear Materials
ATC Management
Atmos Energy
AVANGRID
Avista
Berkshire Hathaway Energy
Black Hills
Blue Ridge Electric Membership
Boardwalk Pipeline Partners
BWX Technologies
California Independent System Operator
Calpine
CenterPoint Energy
CH Energy Group
Cheniere Energy
Chesapeake Utilities
Citizens Energy Group
CLEAResult
Cleco
CMS Energy
Colorado Springs Utilities
Covanta Corporation
CPS Energy
DCP Midstream
Direct Energy
Dominion Energy
Duke Energy
Duquesne Light
Dynegy
Edison International
ElectriCities of North Carolina
Electric Power Research Institute
El Paso Electric
Enable Midstream Partners
Energy Northwest
Energy Transfer Partners
EnLink Midstream
Entergy
EQT Corporation
ERCOT
Lower Colorado River Authority
McDermott International
MDU Resources
Midwest Independent Transmission System Operator
Monroe Energy
MRC Global, Inc.
National Grid USA
New York Power Authority
NextEra Energy, Inc.
NiSource
NorthWestern Energy
NOVA Chemicals
NRG Energy
Nuscale Power
NW Natural
OGE Energy
Oglethorpe Power
Old Dominion Electric
Omaha Public Power
Oncor Electric Delivery
ONE Gas
ONEOK
Orlando Utilities Commission
Otter Tail
Pacific Gas & Electric
Peoples Natural Gas
Pinnacle West Capital
PJM Interconnection
PNM Resources
Portland General Electric
PPL
Public Service Enterprise Group
Puget Sound Energy
Salt River Project
Santee Cooper
SCANA
Sempra Energy
South Central Connecticut Regional Water Authority
Southern Company Services
Southern Maryland Electric Cooperative
South Jersey Industries
Southwest Gas
Spectra Energy
Spire
STP Nuclear Operating
Summit Midstream
Talen Energy

Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

2017 Willis Towers Watson CDB Energy Services Executive Compensation Survey

Participant List

Eversource Energy
Exelon
FirstEnergy
First Solar
Frank's International
Genesis Energy
Great River Energy
ICF International
Idaho Power
ISO New England
ITC Holdings
JEA
Kinder Morgan
Knoxville Utilities Board
LG&E and KU Energy
TECO Energy
Tennessee Valley Authority
Texas Reliability Entity, Inc.
TransCanada
UGI
Unitil
UNS Energy
URENCO
Vectren
Vistra Energy
Westar Energy
Williams Companies
Wisconsin Energy
Wolf Creek Nuclear
Xcel Energy

Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

2017 Willis Towers Watson CDB Energy Services Middle Management, Professional and Support Compensation Survey

Participant List

ALLETE
Alliant Energy
Alyeska Pipeline Service
Ameren
American Electric Power
Areva
AREVA Nuclear Materials
Associated Electric Cooperative
ATC Management
Atlantic Trading & Marketing
Atmos Energy
AVANGRID
Avista
Bechtel Marine Propulsion - Bettis
Bechtel Nuclear, Security & Environmental
Black Hills
Blattner Energy
Boardwalk Pipeline Partners
BWX Technologies
California Independent System Operator
Calpine
Capital Power
CenterPoint Energy
Centrus Energy Corp
Chelan County Public Utility District
CH Energy Group
Cheniere Energy
Chesapeake Utilities
CLEAResult
Cleco
CMS Energy
Colorado Springs Utilities
Crestwood Equity Partners
DCP Midstream
Direct Energy
DNV GL
Dominion Energy
DTE Energy
Duke Energy
Duquesne Light
Dynegy
EDF Trading
Edison International
Electric Boat Corporation
ElectriCities of North Carolina
El Paso Electric
Enable Midstream Partners
Kinder Morgan
Knoxville Utilities Board
LG&E and KU Energy
Lower Colorado River Authority
Midwest Independent Transmission System Operator
Monroe Energy
National Grid USA
Nebraska Public Power District
Newport News Shipbuilding
New York Power Authority
NextEra Energy, Inc.
NiSource
Noble Energy
NorthWestern Energy
NOVA Chemicals
NRG Energy
Nuscale Power
NuStar Energy
NW Natural
Oak Ridge National Laboratory
OGE Energy
Oglethorpe Power
Old Dominion Electric
Omaha Public Power
Oncor Electric Delivery
ONE Gas
ONEOK
Orlando Utilities Commission
Pacific Gas & Electric
Peoples Natural Gas
Pinnacle West Capital
PJM Interconnection
Platte River Power Authority
PNM Resources
Portland General Electric
PPL
Public Service Enterprise Group
Puget Sound Energy
Saipem
Salt River Project
Santee Cooper
SCANA
Sempra Energy
Sharyland Utilities
Sonnedix
South Central Connecticut Regional Water Authority
Southern Company Services

Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

2017 Willis Towers Watson CDB Energy Services Middle Management, Professional and Support Compensation Survey

Participant List

Enbridge Energy
Energy Northwest
Energy Transfer Partners
ENI US Operating Company
EnLink Midstream
Entergy
Enterprise Products Operating LLP
EPCOR Utilities
EQT Corporation
ERCOT
Eversource Energy
Exelon
FirstEnergy
First Solar
Frank's International
GE Energy
Great Plains Energy
Great River Energy
ICF International
Idaho National Laboratory
Idaho Power
ISO New England
ITC Holdings
JEA
Southern Maryland Electric Cooperative
South Jersey Industries
Southwestern Energy
Southwest Gas
Spire
STP Nuclear Operating
Talen Energy
Targa Resources
T.D. Williamson
TECO Energy
Tennessee Valley Authority
TransCanada
Tri-State Generation & Transmission
Unitil
UNS Energy
URENCO
Vectren
Vistra Energy
Washington Gas
WEC Energy Group
Westar Energy
Williams Companies
Wolf Creek Nuclear
Xcel Energy

Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

2017 American Gas Association Compensation Survey

Participant List

[redacted]

Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

2017 EAP Data Information Solutions Energy Technical Craft Clerical Compensation Survey

Participant List

[redacted]