COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	**)**	
ELECTRIC COMPANY FOR AN ADJUSTMENT	**)**	**CASE NO.**
OF ITS ELECTRIC AND GAS RATES AND FOR	**)**	**2016-00371**
CERTIFICATES OF PUBLIC CONVENIENCE	**)**	
AND NECESSITY	**)**	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
THE FIRST SET OF DATA REQUESTS OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
DATED JANUARY 11, 2017

FILED: JANUARY 25, 2017

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer 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.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Senior Vice President – Operations 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 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President – State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company, 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

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 23rd day of January 2017.

Susan M. Watkins (SEAL)
Notary Public

My Commission Expires:

SUSAN M. WATKINS
Notary Public, State at Large, KY
My Commission Expires Mar. 19, 2017
Notary ID # 485723

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Director – Rates for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, 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 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

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

John P. Malloy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~**My commission expires July 11, 2018**~~
Notary ID # 512743

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 13th day of January 2017.

(SEAL)
Notary Public

My Commission Expires:

April 17, 2019

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gregory J. Meiman**, being duly sworn, deposes and says that he is Vice President, Human Resources for Louisville Gas and Electric Company and Kentucky Utilities Company, 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 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and Louisville Gas and Electric 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.

Valerie L. Scott
Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

W. Seelye
William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of January 2017.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
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 25th day of January 2017.

Judy Schooler
Notary Public (SEAL)

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
~~My commission expires July 11, 2018~~
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says he is Senior Vice President, for Gannett Fleming Valuation and Rate Consultants, LLC, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos
John J. Spanos

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 19th day of January 2017.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 1

Responding Witness: John J. Spanos

Q.1-1. Please provide the schedules contained on pages VI-4 through VI-13 of Exhibit JJS-LGE-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony) as well as all workpapers in support of those schedules in electronic format with all formulas intact.

A.1-1. The attached schedules set forth pages VI-4 through VI-13 of Exhibit JJS-LGE-1 in electronic format. Other workpapers are included in data request responses to the AG.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 2

Responding Witness: John J. Spanos

Q.1-2. Refer to pages 10-11 of Mr. Spanos' Direct Testimony wherein he describes the "dismantlement component" added to the overall net salvage for each production facility. Refer also to pages VIII-2 and VIII-3 of Exhibit JJS-LGE-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony).

a. Please describe and provide copies of all source documentation relied upon to determine that "the dismantlement or decommissioning costs for steam production facilities is best calculated at $40/KW of the assets subject to final retirement. The percentage for dismantlement of hydro and other production facilities is $10/KW of the assets surviving at final retirement with the exception of the combined facility which is $20/KW."

b. Please provide for each production facility the KWs utilized to calculate the "dismantlement component," the calculation of the "dismantlement component," and describe how that calculation was incorporated into the calculation of the net salvage component contained on pages VIII-2 and VIII-3 of Exhibit JJS-LGE-1. Provide all calculations if not provided in response to other requests for exhibits and workpapers in electronic format with all formulas intact.

c. At page 11 starting at line 9, Mr. Spanos states, "The current practice for LG&E includes a low level of terminal net salvage combined with the interim net salvage percentage. In this study, the methodology continues to advance to a more precise practice and is utilized by most utilities. The weighting of the interim and final net salvage by location establishes a more precise recovery pattern for each location." Please describe how the calculation of the overall net salvage percentage reflected in the approved depreciation rates differs from the calculation one in the new depreciation study other than the use of a lower level of terminal net salvage as part of current depreciation rates. Provide the calculations of the overall net salvage showing the interim and terminal net salvage components reflected in the approved depreciation rates and those proposed in this proceeding.

A.1-2.

a) The determination of the $/KW levels for dismantlement of generating facilities was based on numerous studies performed by engineering consulting firms that specialize in the dismantlement of generating facilities and an initial study performed and presented by the American Gas Association and Edison Electric Institute.

   Decommissioning cost estimates are extensive studies performed by experts in the field that establish the cost to complete each task of the demolition and then net the scrap value to determine the overall decommissioning cost. The cost breakdown for these studies is based on returning the site to a brownfield condition. These costs are then converted to a $/KW value based on the MWs of each unit or location. The estimates of decommissioning costs range from $20/KW to $150/KW with a very high percentage around the $40/KW to $50/KW level. Thus, $40/KW was utilized for LGE facilities. Similar analysis was performed for hydro, other production and combined cycle facilities.

b) The attached schedule LGE-KIUC-1-2.xlsx sets forth the calculation of the percentage of the dismantlement costs to the assets to be retired on a terminal basis. These percentages are utilized in the determination of the weighted net salvage percentage as set forth on pages VIII-2 and VIII-3 of the Exhibit JJS-LGE-1.

c) The currently approved net salvage was determined based on a settlement that was not a calculated or analyzed based on costs to dismantle. The amount of 2% of terminal net salvage per unit or location was agreed upon in settlement in order to establish an amount to include in depreciation rates.

LOUISVILLE GAS AND ELECTRIC

DECOMMISSIONING COSTS RELATED TO GENERATING UNITS

UNIT	ESTIMATED RETIREMENT YEAR	MW	ESTIMATED DECOMMISSIONING COSTS ($/KW)	TOTAL DECOMMISSIONING COSTS (CURRENT $)	TOTAL DECOMMISSIONING COSTS (FUTURE $)	ESTIMATED TERMINAL RETIREMENTS
(1)	(2)	(3)	(4)	(5)=(3)*(4)	(6)	(7)
STEAM						
MILL CREEK 1	2032	303	40	12,120,000	18,903,064	
MILL CREEK 2	2034	301	40	12,040,000	19,728,942	
MILL CREEK 3	2038	391	40	15,640,000	28,288,474	
MILL CREEK 4	2042	477	40	19,080,000	38,093,125	
TOTAL MILL CREEK				58,880,000	105,013,605	(1,452,787,796)
TRIMBLE COUNTY 1	2050	383	40	15,320,000	37,266,441	
TRIMBLE COUNTY 2	2066	102	40	4,080,000	14,733,338	
TOTAL TRIMBLE COUNTY				19,400,000	51,999,779	(535,583,282)
TOTAL STEAM				**78,280,000**	**157,013,384**	**(1,988,371,079)**
HYDRO						
OHIO FALLS	2045	52	10	520,000	1,118,004	(92,590,980)
TOTAL HYDRO				**520,000**	**1,118,004**	**(92,590,980)**
OTHER						
CANE RUN 7	2055	31	20	620,000	1,706,358	
CANE RUN 11	2018	14	20	280,000	309,068	
TOTAL CANE RUN				900,000	2,015,426	(90,119,059)
ZORN AND RIVER ROAD GAS TURBINE	2019	14	10	140,000	158,397	(1,857,026)
PADDY'S RUN 11	2018	12	10	120,000	132,458	(36,704,237)
PADDY'S RUN 12	2018	23	10	230,000	253,877	
PADDY'S RUN 13	2031	84	10	840,000	1,278,159	
TOTAL PADDY'S RUN				1,190,000	1,664,494	(37,931,804)
BROWN 5	2031	65	10	650,000	989,052	
BROWN 6	2029	55	10	550,000	796,564	
BROWN 7	2029	55	10	550,000	796,564	
TOTAL BROWN				1,750,000	2,582,180	(60,738,943)
TRIMBLE COUNTY 5	2032	46	10	460,000	717,443	
TRIMBLE COUNTY 6	2032	46	10	460,000	717,443	
TRIMBLE COUNTY 7	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 8	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 9	2034	59	10	590,000	966,784	
TRIMBLE COUNTY 10	2034	59	10	590,000	966,784	
TOTAL TRIMBLE COUNTY				3,280,000	5,302,022	(100,724,301)
TOTAL OTHER				**7,260,000**	**11,722,519**	**(291,371,133)**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 3

Responding Witness: John J. Spanos

Q.1-3. Please provide the schedules contained on pages VIII-2 and VIII-3 of Exhibit JJS- LGE-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony) as well as all workpapers in support of those schedules in electronic format with all formulas intact.

A.1-3. The attached schedule sets forth pages VIII-2 and VIII-3 of Exhibit JJS-LGE-1 in electronic format. Workpapers for this response are included in data request KIUC-1-2.

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

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 4

Responding Witness: John J. Spanos

Q.1-4. Refer to page 15, lines 5-10, of Mr. Spanos' Direct Testimony wherein he describes the appropriate service life for the newer technology meters recorded by the Company in Account 370.20, Meters – AMS. Mr. Spanos states, "The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential of 25 years", to justify his use of the 15-S2.5 survivor curve. Please provide copies of all studies, analyses, or reports relied upon in support of this statement.

A.1-4. The attached schedule sets forth the average service life and survivor curve combination utilized by other electric utilities for new technology meters. These estimates are based on manufacturer's expectations of the assets as well as discussions with utility personnel. The list of companies are not matched to their estimates in order to maintain individual company agreements.

SURVIVOR CURVES FOR NEW TECHNOLOGY METERS

COMPANY	SURVIVOR CURVE
(1)	(2)
COMPANY 1	15-S2.5
COMPANY 2	15-S2.5
COMPANY 3	15-S2.5
COMPANY 4	15-S2.5
COMPANY 5	15-SQ
COMPANY 6	15-S2.5
COMPANY 7	15-S2.5
COMPANY 8	15-S2.5
COMPANY 9	15-S2.5
COMPANY 10	15-S2
COMPANY 11	15-S2.5
COMPANY 12	15-S2
COMPANY 13	15-S0.5
COMPANY 14	15-S2.5
COMPANY 15	15-S2.5
COMPANY 16	15-SQ
COMPANY 17	15-S2.5
COMPANY 18	15-S2.5
COMPANY 19	15-S3
COMPANY 20	15-S2.5
COMPANY 21	20-S2
COMPANY 22	12-S2
COMPANY 23	10-S3
COMPANY 24	15-S2.5
COMPANY 25	21-L0
COMPANY 26	20-S3
COMPANY 27	10-S3
COMPANY 28	20-R2.5
COMPANY 29	15-S3
COMPANY 30	20-S2.5
COMPANY 31	20-R5
COMPANY 32	15-S2.5
COMPANY 33	20-R5
COMPANY 34	14-R3

COMPANY NAME

PUBLIC SERVICE COMPANY OF OKLAHOMA
CENTRAL MAINE POWER COMPANY
POTOMAC ELECTRIC POWER COMPANY
COMMONWEALTH EDISON COMPANY
METROPOLITAN EDISON COMPANY
WEST PENN POWER COMPANY
BLACK HILLS COLORADO ELECTRIC UTILITY COMPANY, LP
IDAHO POWER COMPANY
KANSAS CITY POWER AND LIGHT
INDIANAPOLIS POWER & LIGHT
ARIZONA PUBLIC SERVICE COMPANY
DUQUESNE LIGHT COMPANY
JACKSON ENERGY COOPERATIVE
WISCONSIN PUBLIC SERVICE COMPANY
PPL ELECTRIC UTILITIES CORPORATION
NEVADA POWER COMPANY
SIERRA PACIFIC POWER COMPANY
ALLIANT ENERGY - WISCONSIN POWER & LIGHT
BALTIMORE GAS & ELECTRIC
UGI UTILITIES, INC.
BLACK HILLS POWER COMPANY
SOUTH CAROLINA ELECTRIC & GAS COMPANY
FLORIDA POWER & LIGHT COMPANY
DOMINION VIRGINIA POWER
AVISTA CORPORATION
CHEYENNE LIGHT, FUEL & POWER COMPANY
DUKE ENERGY OHIO
PORTLAND GENERAL ELECTRIC
MAINE PUBLIC SERVICE COMPANY
BANGOR HYDRO-ELECTRIC COMPANY
AMEREN ILLINOIS COMPANY
PECO ENERGY COMPANY
PENNSYLVANIA POWER COMPANY
CENTRAL VERMONT PUBLIC SERVICE COMPANY

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 5

Responding Witness: John J. Spanos

Q.1-5. Refer to pages III-7 and III-8 of Exhibit JJS-LGE-1 (Depreciation Study attached to Mr. Spanos' Direct Testimony) and the discussion of life spans for combustion turbines. The study states that "Life spans of 30 to 48 years were estimated for the majority of combustion turbines. These life span estimates are typical for combustion turbines which are used primarily as peaking units."

a. Please describe and provide copies of all source documentation relied upon for this determination and the determination that the newer CT units should have a life span at the low end of the cited range, or 30 years.

b. Please explain the differences in the combustion turbine generating units considered to explain why the proposed life span for the newer CT units is 30 years while the proposed life span for the units installed in 1970, such as Paddy's Run Generator Units 11 and 12, is 48 years.

A.1-5.

a. The life spans for combustion turbines have been established and approved in past studies. These life spans are based on the operational practices of the units and the commonly utilized life span for similar facilities. These type of units are primarily peakers with numerous starts per year with very few hours of operations each start. Given how the CTs fit into the generation demands the overall life cycle is 30 years.

b. The proposed life spans of older units such as Paddy's Run Units 11 and 12 is longer because these units have had capital expenditures during their life cycle that allows them to continue to operate for the limited hours needed per year. These units only meet peaking hours and are rarely dispatched for utilization so overhauls are scheduled over longer periods for these type of units. The early vintage combustion turbines were not utilized in the same fashion as the newer combustion turbines so they had different demands. Many are maintained just to be prepared for occasional heavy loads or quick start requirements.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 6

Responding Witness: John J. Spanos

Q.1-6. Refer to the present and proposed depreciation rates shown for steam and other production plant on the tabs LGE Depr Rates and LGE Proposed Depr Rates on the Excel spreadsheet titled Att_LGE_PSC_1-54_Sch_B. Provide the calculation of the net salvage percentage. At a minimum, show the terminal net salvage costs, the calculation of the terminal net salvage percentages, interim net salvage percentages, and the weighting of the interim and terminal net salvage percentages.

A.1-6. The attached schedule sets forth the development of the weighted net salvage utilized in the depreciation study. These percentages are set forth in LGE_PSC_1-54_Sch_B-3.2F.

LOUISVILLE GAS AND ELECTRIC COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2015

		Terminal Retirements			Interim Retirements			Total		Estimated
		Retirements	Net Salvage	Net Salvage	Retirements	Net Salvage	Net Salvage	Net Salvage	Total	Net Salvage
	Account	($)	($)	(%)	($)	(%)	($)	($)	Retirements	(%)
	(1)	(2)	(3)	(4)=(3)/(2)	(5)	(6)	(7)=(5)x(6)	(8)=(3)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	STEAM PRODUCTION PLANT									
	CANE RUN GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	17,304,448	(1,730,445)	(10)	-	(25)	-	1,730,445	17,304,448	(10)
312	BOILER PLANT EQUIPMENT	11,298,863	(1,129,886)	(10)	-	(25)	-	1,129,886	11,298,863	(10)
314	TURBOGENERATOR UNITS	1,179,946	(117,995)	(10)	-	(20)	-	117,995	1,179,946	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	-	0	(10)	-	(10)	-	-	-	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	607,624	(60,762)	(10)	-	(5)	-	60,762	607,624	(10)
	TOTAL CANE RUN GENERATING STATION	*30,390,880*	*(3,039,088)*		-		-	*3,039,088*	*30,390,880*	*(10)*
	MILL CREEK GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	132,884,292	(9,301,900)	(7)	9,584,902	(25)	2,396,225	11,698,126	142,469,193	(10)
312	BOILER PLANT EQUIPMENT	1,134,783,598	(79,434,852)	(7)	233,961,793	(25)	58,490,448	137,925,300	1,368,745,392	(10)
314	TURBOGENERATOR UNITS	115,884,838	(8,111,939)	(7)	27,463,353	(20)	5,492,671	13,604,609	143,348,191	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	60,982,930	(4,268,805)	(7)	17,962,115	(10)	1,796,211	6,065,016.59	78,945,045	(10)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	8,252,138	(577,650)	(7)	2,843,010	(5)	142,151	719,800	11,095,148	(10)
	TOTAL MILL CREEK GENERATING STATION	*1,452,787,796*	*(101,695,146)*		*291,815,173*		*68,317,706*	*170,012,852*	*1,744,602,969*	*(10)*
	TRIMBLE COUNTY GENERATING STATION									
311	STRUCTURES AND IMPROVEMENTS	115,796,487	(13,895,578)	(12)	13,775,802	(25)	3,443,951	17,339,529	129,572,290	(16)
312	BOILER PLANT EQUIPMENT	328,399,033	(39,407,884)	(12)	210,665,343	(25)	52,666,336	92,074,220	539,064,375	(16)
314	TURBOGENERATOR UNITS	50,628,287	(6,075,394)	(12)	28,717,718	(20)	5,743,544	11,818,938	79,346,005	(16)
315	ACCESSORY ELECTRIC EQUIPMENT	38,063,453	(4,567,614)	(12)	24,640,488	(10)	2,464,049	7,031,663	62,703,941	(16)
316	MISCELLANEOUS POWER PLANT EQUIPMENT	2,696,022	(323,523)	(12)	3,371,487	(5)	168,574	492,097	6,067,508	(16)
	TOTAL TRIMBLE COUNTY GENERATING STATION	*535,583,282*	*(64,269,994)*		*281,170,837*		*64,486,453*	*128,756,447*	*816,754,120*	*(16)*
	TOTAL STEAM PRODUCTION PLANT	**2,018,761,959**	**(169,004,228)**		**572,986,010**		**132,804,159**	**301,808,387**	**2,591,747,969**	*(12)*
	HYDRAULIC PRODUCTION PLANT									
	OHIO FALLS									
331	STRUCTURES AND IMPROVEMENTS	6,235,864	(62,359)	(1)	1,636,144	(20)	327,229	389,587	7,872,008	(2)
332	RESERVOIRS, DAMS AND WATERWAYS	16,858,152	(168,582)	(1)	180,031	(10)	18,003	186,585	17,038,183	(2)
333	WATER WHEELS, TURBINES AND GENERATORS	60,681,411	(606,814)	(1)	1,435,991	(20)	287,198	894,012	62,117,401	(2)
334	ACCESSORY ELECTRIC EQUIPMENT	7,694,049	(76,940)	(1)	526,420	(10)	52,642	129,582	8,220,469	(2)
335	MISCELLANEOUS POWER PLANT EQUIPMENT	1,110,681	(11,107)	(1)	79,141	(10)	7,914	19,021	1,189,822	(2)
336	ROADS, RAILROADS AND BRIDGES	10,822	(108)	(1)	19,108	0	-	108	29,931	(2)
	TOTAL OHIO FALLS	*92,590,980*	*(925,910)*		*3,876,834*		*692,986*	*1,618,896*	*96,467,814*	*(2)*
	TOTAL HYDRAULIC PRODUCTION PLANT									
	OTHER PRODUCTION PLANT									
	BROWN CTS									
341	STRUCTURES AND IMPROVEMENTS	1,095,411	(98,587)	(9)	25,661	(5)	1,283	99,870	1,121,072	(9)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,975,276	(177,775)	(9)	100,418	(10)	10,042	187,817	2,075,694	(9)
343	PRIME MOVERS	43,182,895	(3,886,461)	(9)	11,296,333	(10)	1,129,633	5,016,094	54,479,228	(9)
344	GENERATORS	8,043,492	(723,914)	(9)	113,412	(10)	11,341	735,255	8,156,904	(9)
345	ACCESSORY ELECTRIC EQUIPMENT	4,093,891	(368,450)	(9)	450,766	(10)	45,077	413,527	4,544,656	(9)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,347,978	(211,318)	(9)	92,751	0	-	211,318	2,440,729	(9)
	TOTAL BROWN CTS	*60,738,943*	*(5,466,505)*		*12,079,340*		*1,197,376*	*6,663,881*	*72,818,283*	*(9)*

LOUISVILLE GAS AND ELECTRIC COMPANY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2015

Account	Terminal Retirements: Retirements ($)	Terminal Retirements: Net Salvage ($)	Net Salvage (%)	Interim Retirements: Retirements ($)	Interim Retirements: Net Salvage (%)	Interim Retirements: Net Salvage ($)	Total Net Salvage ($)	Total Retirements	Estimated Net Salvage (%)
(1)	(2)	(3)	(4)=(3)/(2)	(5)	(6)	(7)=(5)x(6)	(8)=(3)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
CANE RUN CT									
341 STRUCTURES AND IMPROVEMENTS	12,019,704	(240,394)	(2)	4,912,788	(5)	245,639	486,033	16,932,492	(4)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	31,002,131	(620,043)	(2)	7,143,777	(10)	714,378	1,334,420	38,145,908	(4)
343 PRIME MOVERS	10,146,406	(202,928)	(2)	15,012,714	(10)	1,501,271	1,704,199	25,159,120	(4)
344 GENERATORS	31,933,371	(638,667)	(2)	2,719,179	(10)	271,918	910,585	34,652,550	(4)
345 ACCESSORY ELECTRIC EQUIPMENT	5,014,446	(100,289)	(2)	2,487,893	(10)	248,789	349,078	7,502,339	(4)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	3,001	(60)	(2)	550	0	-	60	3,552	(4)
TOTAL CANE RUN CT	*90,119,059*	*(1,802,381)*		*32,276,901*		*2,981,996*	*4,784,377*	*122,395,961*	*(4)*
PADDY'S RUN									
341 STRUCTURES AND IMPROVEMENTS	2,421,692	(217,952)	(9)	56,485	(5)	2,824	220,777	2,478,177	(9)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	2,124,703	(191,223)	(9)	162,867	(10)	16,287	207,510	2,287,570	(9)
343 PRIME MOVERS	17,643,950	(1,587,956)	(9)	4,780,347	(10)	478,035	2,065,990	22,424,297	(9)
344 GENERATORS	10,479,887	(943,190)	(9)	254,134	(10)	25,413	968,603	10,734,021	(9)
345 ACCESSORY ELECTRIC EQUIPMENT	4,017,383	(361,564)	(9)	316,103	(10)	31,610	393,175	4,333,486	(9)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	1,244,189	(111,977)	(9)	48,756	0	-	111,977	1,292,945	(9)
TOTAL PADDY'S RUN	*37,931,804*	*(3,413,862)*		*5,618,692*		*554,169*	*3,968,032*	*43,550,496*	*(9)*
TRIMBLE COUNTY CTS									
341 STRUCTURES AND IMPROVEMENTS	11,160,285	(558,014)	(5)	292,711	(5)	14,636	572,650	11,452,996	(6)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	3,280,291	(164,015)	(5)	300,890	(10)	30,089	194,104	3,581,180	(6)
343 PRIME MOVERS	64,621,563	(3,231,078)	(5)	21,599,455	(10)	2,159,945	5,391,024	86,221,017	(6)
344 GENERATORS	9,908,224	(495,411)	(5)	160,911	(10)	16,091	511,502	10,069,135	(6)
345 ACCESSORY ELECTRIC EQUIPMENT	11,699,800	(584,990)	(5)	1,372,073	(10)	137,207	722,197	13,071,873	(6)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	54,139	(2,707)	(5)	1,439	0	-	2,707	55,577	(6)
TOTAL TRIMBLE COUNTY CTS	*100,724,301*	*(5,036,215)*		*23,727,478*		*2,357,968*	*7,394,183*	*124,451,779*	*(6)*
ZORN AND RIVER ROAD CTS									
341 STRUCTURES AND IMPROVEMENTS	7,614	(381)	(5)	627	(5)	31	412	8,241	(5)
342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES	22,664	(1,133)	(5)	770	(10)	77	1,210	23,434	(5)
343 PRIME MOVERS	-	0	(5)	-	(10)	-	-	-	(5)
344 GENERATORS	1,730,639	(86,532)	(5)	96,942	(10)	9,694	96,226	1,827,581	(5)
345 ACCESSORY ELECTRIC EQUIPMENT	86,627	(4,331)	(5)	7,441	(10)	744	5,076	94,069	(5)
346 MISCELLANEOUS POWER PLANT EQUIPMENT	9,482	(474)	(5)	6	0	-	474	9,488	(5)
TOTAL ZORN AND RIVER ROAD CTS	*1,857,026*	*(92,851)*		*105,787*		*10,547*	*103,398*	*1,962,813*	*(5)*
TOTAL OTHER PRODUCTION PLANT	**291,371,133**	**(15,811,815)**		**73,808,198**		**7,102,056**	**22,913,871**	**365,179,331**	
GRAND TOTAL	**2,402,724,072**	**(185,741,952)**		**650,671,042**		**140,599,201**	**326,341,154**	**3,053,395,114**	

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 7

Responding Witness: John J. Spanos

Q.1-7. Please provide a copy of all notes drafted by Mr. Spanos and/or his colleagues and all other workpapers and source documents relied on but not previously supplied in response to the Commission's MFR or Staff First Set.

A.1-7. All notes and source documents have been previously supplied in response to the Commission's MFR or Staff First Set of questions as well as the data requests from the AG.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 8

Responding Witness: John J. Spanos

Q.1-8. Please provide a copy of all notes drafted by Mr. Spanos and/or his colleagues and all other workpapers and source documents relied on but not previously supplied in response to the Commission's MFR or Staff First Set.

A.1-8. See the response to Question No. 7.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 9

Responding Witness: John P. Malloy / John J. Spanos

Q.1-9. Please provide the Companies' estimated remaining service life for the SAP CCS as of December 31, 2015. Is it the Companies' plan to retire the CCS in mid-2019? If not, then what is the expected retirement date of the CCS? Provide a copy of all support for your response, including a copy of all documents that address the timeline and upgrade schedule for the CCS and its ultimate retirement and replacement. If none, then please so state.

A.1-9. As of December 31, 2015, the CCS system had been in place since April 2009, 6+ years of a 10 year asset life cycle. An upgrade to the system began in early 2016 and will be installed mid-2017. Therefore the new asset life will be 10 years from 2017 to 2027. The mid-term IT plan is to upgrade the system over the 2021 and 2022 timeframe. There are no current plans to replace the CCS system.

The support for the original 10 year CCS life can be found at LG&E in Case No. 2012-00222, LGE_Direct_Testimony_All, John J Spanos Testimony, Schedule III-13. The support for the 10 year CCS life extension can be found at Spanos Testimony, Exhibit JJS-LGE-1, Page 65. The testimony of Mr. Spanos is available at: http://psc.ky.gov/pscecf/2012-00222/rick.lovekamp%40lge-ku.com/06292012/LGE_Direct_Testimony_-_All.pdf.

For the timeline and upgrade schedule, see attached, which is being filed under seal pursuant to a Petition for Confidential Protection. The Current SAP Upgrade is denoted as "SAP – CRM/ECC Upgrade" and the future upgrade is denoted as "SAP HANA Upgrade."

CONFIDENTIAL

Customer Service

in thousands

variance in (red) designates an unfavorable increase

Original 2017 BP Amounts

Projects	2017 Total	2018 Total	2019 Total	2020 Total	2021 Total
[redacted] CONFIDENTIAL INFORMATION REDACTED [redacted]					
SAP CRM/ECC Upgrade	$ 9,552	$ -	$ -	$ -	$ -
[redacted]					
SAP HANA Upgrade	$ -	$ -	$ -	$ -	$ 4,000
[redacted]					

CONFIDENTIAL

Projects	2017 Total	2018 Total	2019 Total	2020 Total	2021 Total
[redacted]					
[redacted]					
[redacted]					

CONFIDENTIAL

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 10

Responding Witness: John J. Spanos / Lonnie E. Bellar

Q.1-10. Please provide the probable retirement dates used for each of the Company's generating units and the source documents relied on for this purpose. Identify the Company witness, other than Mr. Spanos, who provided and can testify as to the probable retirement dates.

A.1-10. The Company does not assign retirement dates to its generating units, however, probable retirement dates are projected in order to calculate depreciation based on a concurrent retirement of assets. See also the Company's response to AG 1-193 and 1-194. Concerning the second part of the request, please see the "Responding Witness" line above.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 11

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

Q.1-11. Refer to page 16 of 219 of 807 KAR:001 Section 16(7)(c), which shows the proposed demolition schedules for the Company's retired generating plants.

a. Please describe the present status of each of the retired plants, including the extent of facility decommissioning, dismantlement, and site remediation to date.

b. Please describe the full extent of the planned dismantlement and site remediation for each of the retired plants.

c. Please identify each statute, regulation, and/or rule that requires the demolition of each of the retired plants and explain in layman's terms why it requires dismantlement and site remediation between now and 2022 as opposed to maintain the present status for the indefinite future or until there are definitive site development plans.

d. Provide the year of retirement for each of the retired plants.

e. Please provide a copy of the Company's business case and/or all other economic and/or other studies that support the Company's decision to proceed with demolition.

f. Please provide the Company's cost estimates to demolish each of the retired plants as well as all underlying studies and documentation.

g. For each retired plant, indicate whether the Company will proceed with demolition if the cost is not included in the revenue requirement.

h. Please provide the Company's demolition cost estimate for each of the retired plants, including all supporting documentation.

A.1-11.

a. Paddy's Run – the chimneys were taken down in 2012 and 2013 due to safety concerns with the failing exteriors of the chimneys and their location immediately adjacent to the electrical switching station. The generating facility is currently under contract for abatement and demolition to Brandenburg. Asbestos and lead abatement is approximately 80% complete and demolition is approximately 10% complete. Demolition of structures, as well as final site restoration (grading, river bank rip-rapping, and seeding of grasses), is scheduled to be completed by the end of 2017.

   Cane Run – the Unit 4/5 sludge processing plant was demolished in 2016. The facility has undergone decommissioning activities since its retirement in late 2015 such as the draining and disposal of oils and disconnection of miscellaneous non-essential electrical systems. Power to the facility has been minimized to specific security/access lighting, heating of specific areas, flood control sump pump(s) and substation controls. The various tanks are drained and substantial ash removed from systems.

b. See attached for Paddys Run Technical Specifications/Statement of Work. See attached for Cane Run Technical Specifications as the engineering is not completed. The engineering of the statement of work for Canal has not been initiated, but will be developed consistent with those of Paddys Run and Cane Run, including the lessons-learned from the Paddy's Run on-going demolition project.

c. LG&E is not aware of a statute, regulation, and/or rule that requires the demolition of these facility structures. The demolitions are being performed to eliminate on-going maintenance and capital cost associated with these unmanned structures. Regulations do require broken windows from vandalism and weather decay be maintained, as well as the exterior sidings, brick/mortar and roofing systems need maintenance or replacement to protect the interior piping and electrical systems from the weather. On-going maintenance from acts of vandalism will be eliminated along with the public safety risk, risk of flood damage, and other liabilities associated with unsecured and unmanned facilities that the public could access from the public Kentucky waterways that these facilities are located on.

d. Paddy' Run was taken out of service in 1984, Cane Run in 2015 and Canal in 1966.

e. For Paddy's Run see attachment to response to b. The business cases for Cane Run and Canal have not been completed. The plan has been to complete the demolition statement of work studies, bid the demolition work and then prepare business cases as part of the project and demolition contract award process.

f. See attached.

g. The Company has included the proposed demolition costs because it believes it is prudent for safety reasons to demolish the facilities. If the Commission believes it is not prudent and disallows the recovery of any or all of those costs, the Company will have to reevaluate how to proceed

h. See the response to Question No. 11(f).

EXHIBIT A
TECHNICAL SPECIFICATIONS
ABATEMENT AND DEMOLITION OF THE
LG&E PADDYS RUN GENERATING STATION

TABLE OF CONTENTS

LIST OF APPENDICES

APPENDIX A SPECIFICATIONS

Specification Number	Specification Title
01 14 00	Work Restrictions
01 33 00	Submittal Procedure
01 35 26	Safety Requirements
01 45 00 00 10	Quality Control
01 50 00	Temporary Construction Facilities and Controls
01 57 19 00 20	Temporary Environmental Controls
01 57 23	Temporary Storm Water Pollution Control
01 74 19	Demolition Waste Management
02 41 00	Demolition and Deconstruction
02 65 00	USTs
02 66 00	Select Fill and Topsoil for Cap Cover
02 81 00	Waste Transportation and Disposal
02 82 14.00 10	Asbestos Abatement
02 83 13.00 20	Lead in Construction
02 84 16	Universal Waste
02 84 33	PCB Oils
31 05 19	Geotextile
31 11 00	Clearing and Grubbing
31 23 00 00 20	Excavation and Fill
32 11 24	Graded Crushed Aggregate Base Course for Pavement
32 92 19	Seeding

APPENDIX B DRAWINGS

Sheet Number	Sheet Title	Sheet Description	
1 of 27	PR0-C-10001-C-001	COVER SHEET	-
2 of 27	PR0-C-10002-C-002	INDEX SHEET	.
3 of 27	PR0-C-10003-C-003	CIVIL LEGEND AND ABBREVIATIONS	.
4 of 27	PR0-C-10004-C-004	CIVIL GENERAL NOTES	.
5 of 27	PR0-C-10005-C-005	SITE ACCESS PLAN	.
6 of 27	PR0-C-10006-C-006	EXISTING SITE PLAN	.
7 of 27	PR0-C-10007-C-007	EXISTING UTILITIES PLAN	.
8 of 27	PR0-C-10008-C-008	LIMITS OF TREE CLEARING	.
9 of 27	PR0-C-10009-C-009	MAIN PLANT DRAINAGE SYSTEM	
10 of 27	PR0-C-10010-C-010	FINAL RESTORATION & GRADING PLAN	
11 of 27	PR0-C-10011-C-011	CIVIL DETAILS	TYPICAL CROSS SECTION

Sheet Number	**Sheet Title**	**Sheet Description**	
12 of 27	Not Used.		
13 of 27	Not Used.		
14 of 27	PR0-C-10014-C-014	CIVIL DETAILS	HDPE PIPE AND FITTING DETAILS
15 of 27	PR0-C-10015-C-015	CIVIL DETAILS	OUTFALL HEADWALL AND FLAPGATE
16 of 27	PR0-C-10016-C-016	CIVIL DETAILS	TRANSMISSION LINE RELOCATION (BY OTHERS)
17 of 27	PR0-C-10017-C-017	CIVIL CROSS SECTIONS	CROSS SECTION LOCATIONS
18 of 27	PR0-C-10018-C-018	CIVIL CROSS SECTIONS	SCRUBBER BUILDING AND SCRUBBER PUMP HOUSE
19 of 27	PR0-C-10019-C-019	CIVIL CROSS SECTIONS	SCREEN HOUSE #3 AND MAIN PLANT BUILDING SHAKER HOUSE
20 of 27	PR0-C-10020-C-020	CIVIL CROSS SECTIONS	SCREEN HOUSE #2 AND MAIN PLANT BUILDING
21 of 27	PR0-C-10021-C-021	CIVIL CROSS SECTIONS	SCREEN HOUSE #1 AND MAIN PLANT BUILDING
22 of 27	PR0-C-10022-C-022	CIVIL CROSS SECTIONS	SCREEN HOUSES AND MAIN PLANT BUILDING
23 of 27	PR0-C-10023-C-023	CIVIL CROSS SECTIONS	MAIN POWER PLANT
24 of 27	PR0-C-10024-C-024	CIVIL CROSS SECTIONS	SHAKER HOUSE
25 of 27	PR0-C-10025-C-025	CIVIL SITE PHOTOS	.
26 of 27	PR0-C-10026-C-026	CIVIL SITE PHOTOS	.
27 of 27	PR0-C-10027-C-027	CIVIL SITE PHOTOS	

Information provided to Contractor concerning the Job Site, other portions of the Paddys Run Generating Station Site, the Existing Facilities, the Facility or surrounding areas (including the information provided in Exhibit A (or any other Exhibit to this Agreement), the NESHAPS and other regulated material survey prepared by Owner Engineer, and all drawings and other information provided to Contractor in the process leading up this Agreement, and information provided after the Effective Date) is made without representation or warranty of any kind or nature. Such information is not warranted by Owner to be accurate, complete, or otherwise suitable or sufficient for Contractor's purposes and is provided solely as a convenience to Contractor. Any reliance thereon by Contractor is at its sole risk. Differing Conditions will neither be deemed nor constitute an Excusable Event Basis. All distances and elevations contained in the Appendix B Drawings are approximate.

1.0 Background

The Paddys Run Generating Station is owned by Louisville Gas and Electric Company (LG&E). Paddys Run Generating Station is an approximately 39-acre property located in Louisville, Kentucky in an industrial area at the west end of Bells Lane on the east bank of the Ohio River. The property contains a portion of the Ohio River flood protection system, the shuttered coal-fired generating facility (including ancillary structures), an active switching station, and three (3) active gas turbine generating units. The Job Site is depicted on drawing PRO-C-10004-C004, 005, and 006.

The coal-fired generating facility, developed in the 1940s thru the 1950s, includes the following structures: the power station building containing six (6) former coal burning boiler generating units, rail lines that serviced the power station building and the coal shaker house, three (3) screen house water intake structures, a scrubber system on unit 6, a scale house, two (2) deep wells, one (1) coal shaker house and associated conveyor system, brine sump, and a number of underground storage tanks (USTs) and above ground storage tanks (ASTs).

The coal-fired generating facility has been inactive since the early 1980s. The five (5) large chimneys were demolished in 2012. Hazardous Substances exist throughout the Job Site. Due to the lack of building maintenance, the structural and mechanical systems are in a continual state of decline and present environmental and safety issues.

There are three (3) sets of transmission lines crossing the Ohio River on the southern portion of the property. The one (1) active river-crossing transmission line utilizes a tower mounted on the roof of the main powerhouse structure. Owner will relocate this line in accordance with the applicable provision in the Body of the Agreement.

2.0 Statement of Work

This Exhibit A, including Appendices A and B, compose the Technical Specifications. Contractor is obligated to perform the Work in full compliance with the Project Requirements including these Technical Specifications. The provisions of these Technical Specifications are not intended to be a substitute for or in any way diminish the Project Requirements. If the Project Requirements require more or different Work than that set forth in these Technical Specifications, Contractor shall also perform such Work. If any of the provisions of these Technical Specifications is inconsistent with (i.e., not permitted under) any of the Project Requirements, Contractor shall notify Owner to that effect and Owner will amend the Technical Specifications to eliminate the inconsistency. Neither such amendment, nor any other differences between these Technical Specifications and the other Project Requirements shall constitute an Excusable Event, a Change Order, or otherwise entitle Contractor to any Adjustment.

This statement of work is an overview of the Work and is subject to the more detailed specifications of Appendices A and B. The Work includes five (5) major phases: mobilization, abatement, demolition, restoration and demobilization. The structures requiring abatement and demolition are in poor condition. These structures contain Hazardous Substances. Contractor shall locate all Hazardous Substances that exist at the Job Site (including hazardous building material, contents of USTs and ASTs, PCBs, asbestos, and all other Hazardous Substances), determine what each Hazardous Substance is (i.e., characterize), and properly and safely abate, remove, handle, store, transport, and dispose of each Hazardous Substance (and maintain full records of each such step) (all of the foregoing, Abate). All such Abatement for a structure shall be completed before any demolition of that structure except to the extent that it is not practical to do so and Abatement after commencement of demolition can be done properly and safely.

Contractor shall perform all Work in a manner so as to not impact (or otherwise put at risk) the normal operations of the facilities at the Paddys Rune Generating Station Site, including those of the switching station, transmission lines, and gas turbine generating units. Without limiting the foregoing, Contractor shall avoid causing excessive vibrations. Contractor shall complete all demolition above each elevation of a structure before the supporting members on the lower level of that structure are disturbed. Contractor shall not commence demolition on any structures that are clad in whole or in part with transite (or other Hazardous Substance containing) panels until such panels are Abated.

Certain structures on the Job Site (including the coal shaker house and associated conveyor system, deep wells and electrical conduits that transect the levee) are integral to the Ohio River flood protection system. Contractor shall perform the Work so that such Work in no way lessens the effectiveness of the existing levee or the Ohio River flood protection system.

2.1 Job Site Access

All personnel working at Paddys Run are required to receive LG&E specific Passport Training prior to commencing Work at the Job Site and annually thereafter. Much of the Job Site is open and accessible via vehicle or foot travel. However, some of the Job Site is not accessible to vehicle traffic. Contractor shall make such areas accessible.

2.2 Abatement

Contractor shall remove all of the Hazardous Substances in the structures on the Job Site and any other Hazardous Substances Contractor encounters within the Job Site in accordance with the Hazardous Substances Management Plan and the Project Requirements.

2.3 USTs and ASTs

Contractor shall remove all ASTs and USTs on the Job Site in accordance with the Hazardous Substances Management Plan and the Project Requirements.

2.4 Temporary Stormwater Pollution and Environmental Controls

Prior to performing any other Work at the Job Site, Contractor shall install (and thereafter maintain) temporary stormwater pollution and environmental controls in accordance with the Hazardous Substances Management Plan and the Project Requirements. Contractor responsible for employing means and methods necessary to prevent emissions of runoff, dust and debris from leaving the site and specifically to prevent any such emissions from impacting the adjacent switch yard located to the east of the facility.

2.5 Demolition

Contractor shall demolish all structures on the Job Site (except the levee) and properly dispose of all materials and debris from such demolition in accordance with the Hazardous Substances Management Plan and the Project Requirements. Contractor shall demolished the foundations (including interior walls) of all such structures to a depth of 3 feet below the ground surface level (as such level shall exist after restoration of the Job Site). The following provisions provide additional details for certain structures:

2.5.1 Shaker House

The Coal Hopper Unloading Building (also referred to as the Shaker House) is within the footprint of the existing levee system east of Paddys Run. To avoid impacting the levee, Contractor shall not demolish the existing Coal Hopper Unloading Building below elevation 460.00'.

Remove all rail steel associated with the Coal Hopper Unloading Building from the southern portion of the work area to 125' South of the Shaker House.

2.5.2 Scale House and Well

Contractor shall demolish of the Scale House taking care not to damage the water well riser in the southern portion of this structure. Contractor responsible for removing the well housing structure and coordinating with Owner's well closure contractor. Well to be closed by others.

2.5.3 Screen House 1, 2 & 3

As part of the demolition of the screen houses, Contractor shall demolish all pipes leading from the screen houses to the east side of the power station and the bridge adjacent to each screen house over the pipes. During the demolition, Contractor may permit concrete and reinforcing steel to fall into each screen house and fill to an elevation not to exceed 3' below final grade. Discharge conduits shall be filled with rubble fill to the elevation of the top of the tunnels, with a flowable fill plug 10' South of the Southwest corner of the main Power Station.

2.5.4 Chlorine Storage

Contractor shall not demolish the cast in place reinforced concrete platform on which the chlorine storage structure is erected. Contractor shall take care not to damage this platform as it is demolishing the remainder of the chlorine storage structure and other portions of the Work.

2.5.5 Fly Ash Silo

Contractor shall not disturb the fly ash silo until it has removed all of the fly ash inside.

Contractor shall not remove the concrete footings associated with the fly ash silo. These footings are an integral part of the levee and will not be removed.

2.5.6 Power Station

Contractor to remove this structure to 3' below final grade or as described below or on the drawings. Work to be phased to stabilize the site traffic, work control and especially the preservation of the active high power lines which are supported by a roof mounted transmission tower (see drawings).

Contractor to remove basement walls to 3' below final grade. Along the east wall there are numerous penetrations which are the terminations of conduits which extend towards/through the Levee. The filling of penetrations will be done by others. Contractor to coordinate with LG&E's contractor to allow safe and timely access to perform the filling of penetrations that extend towards/through the Levee. Along the west side of the basement, Contractor shall demolish the foundation walls to the top of the basement concrete floor.

2.5.7 Quonset Structure

Contractor shall not demolish the quonset structure.

2.6 Restoration

Contractor shall restore the Job Site to ensure positive drainage from the toe of the levee to the Ohio River. The general area will be restored, graded and seeded/sodded to promote vegetation growth to minimize future erosion of any placed topsoil in accordance with the Project Requirements.

As part of the restoration, Contractor shall remove all of its temporary facilities. Temporary erosion control will also be removed once the site vegetation is re-established.

As part of the restoration, Contractor shall provide an engineered fill cap from the western toe of the levee across the power station foundation restoration area to the western side of the screen houses in accordance with the Project Requirements. The following provisions provide additional details for certain portions of the restoration:

2.6.1 Shaker House and Coal Conveyor Restoration

After demolition of the shaker house and the coal conveyor, the sub-surface sections of these structures are to be backfilled with a “flowable” fill material. An engineered levee fill material will be placed atop the “flowable” fill material used to backfill the shaker house. The remaining restoration for the coal conveyor will be performed using an engineered fill.

2.6.1.1. Shaker House Rail and other Rail Restoration

Material to be used for the restoration of the rail bed after removal of the rail lines and rail ties is dependent on the elevation of the area post rail tie removal. Removal of rail ties atop the levee at or below elevation 460.00’ will require the placement of Engineered Levee Fill material to maintain the elevation. Rail lines at elevations above 460.00’ or outside of the footprint of the Levee shall be removed and the resulting ground surface shall be graded for positive drainage.

2.6.2 Screen House and Screen House Gate Restoration

The entire screen house void is to be backfilled with processed demolition concrete/masonry up to an elevation of 3' below final grade.

2.6.3 Unit 6 Scrubber and Scrubber Pump House Restoration

Details for the restoration elevations for the Unit 6 scrubber and scrubber pump house, to include restoration of the two additional concrete pads, are provided on Sheet 18 PRO-C-10018-C-018. Demolition of the sump foundation for the Unit 6 scrubber left the sump foundation three (3) feet below existing grade. The remaining concrete slab and pad areas were demolished to a depth of one (1) foot below existing grade. The restoration for the Unit 6 scrubber and scrubber pump house will be performed using select fill. Specification section 31 23 00.00 20 Excavation and Fill provides the details for the select fill material.

2.6.4 Power Station Restoration

To allow for water to drain from the basement area, Contractor shall install a drainage system in accordance with the Project Requirements. Contractor shall backfill the basement with select fill material.

2.6.5 Security Fence

Contractor shall install a security fence in accordance with the Project Requirements. The Contractor shall not be required to install a security fence adjacent to the Ohio River.

2.7 Demobilization

The Contractor shall remove all Contractor owned/leased equipment and materials. The Contractor shall ensure that all demolition debris, materials to include recyclable materials, asbestos waste, construction debris and all other waste materials are removed from the Job Site and properly managed/disposed.

Contractor shall complete the restoration of the Contractor’s storage and administrative area upon removal of all Contractor owner/leased materials as described in the paragraph above.

EXHIBIT A
TECHNICAL SPECIFICATIONS
CANE RUN GENERATING STATION
PLANT FINAL CLOSURE PROJECT

TABLE OF CONTENTS

EXHIBIT A – APPENDIX A
SPECIFICATIONS
SECTION 01 11 00
SUMMARY OF WORK
08/04/2016

PART 1 GENERAL

1.1 Submittals

All project plans and submittals should be submitted and filed subordinate to one of the six relevant Work Plan referenced in the Agreement 4.20.1.

a. Job Site Coordination Plan
b. Safety and Proper Performance Plan
c. Temporary Facilities Plan
d. Environmental Control Plan
e. Hazardous Substances Management Plan
f. Solid Waste Management Plan

Submittals shall be in accordance with Section 01 33 00 SUBMITTAL PROCEDURES:

1.2 Work Covered by Contract Documents

1.2.1 Project Description and Location:

Contractor shall perform the following: Cane Run Generating Station Plant Final Closure project as more specifically described in Articles 2.0 and 3.0 hereof (hereinafter referred to as the "Work") and Owner shall compensate the Contractor for the Work, under all the terms and conditions hereof.

The Cane Run Generating Station is located in Southwest Jefferson County, Kentucky. The Station may be accessed from Cane Run Road.

The existing coal fired units (units 4, 5 and 6) were retired in the summer of 2015.

The Owner has removed some universal waste (including radiation sources) from the Work area. Available documentation related to the Universal Waste removal is available in the reference set of documents. Contractor shall coordinate with other ongoing site activities that may be occurring on site concurrently

PART 2 DESCRIPTION OF WORK

Except as otherwise expressly provided herein, Contractor shall supply all permits, licenses, labor, supervision, materials, equipment, fuel, tools, temporary field offices, sanitary facilities, power and warehousing, and shall pay all expenses, necessary or appropriate in the performance of the Work. The Work includes asbestos abatement, universal waste removal, demolition, recycling, hauling, disposal and placement of material, dust control and storm water run-off control. Contractor shall perform the "Work" in accordance with the Specifications and Drawings included and referenced herein. The Work includes General Site Requirements, Asbestos and Lead Abatement, Protection of selected buildings and structures, Equipment Demolition, and site restoration as set forth below.

The objective of this project is to removal all structures to grade where the adjacent grade is pavement; to 2' below final grade where structures are not surrounded by pavement; and to the basement level in the case of the main power station. The East Wall below the operating floor of the East Power Station must be protected from damage as it is part of the protected Levee structure. Measures will be taken as demolition progresses to ensure that the East wall is stabilized and preserved in its present state.

This Exhibit A, including Appendices A and B, compose the Technical Specifications. Contractor is obligated to perform the Work in full compliance with the Project Requirements including these Technical Specifications. The provisions of these Technical Specifications are not intended to be a substitute for or in any way diminish the Project Requirements. If the Project Requirements require more or different Work than set forth in these Technical Specifications, Contractor shall also perform such Work. If any of the provisions of these Technical Specifications is inconsistent with (i.e., not permitted under) any of the Project Requirements, Contractor shall notify Owner to that effect and Owner will amend the Technical Specifications to eliminate the inconsistency. Neither such amendment, nor any other differences between these Technical Specifications and the other Project Requirements shall constitute an Excusable Event, a Change Order, or otherwise entitle Contractor to any adjustment.

This statement of work is an overview of the Work and is subject to the more detailed specifications of Appendices A and B. The Work includes five (5) major phases: mobilization, abatement, demolition, restoration and demobilization. The structures requiring abatement and demolition are in fair to good condition. These structures contain Hazardous Substances. Contractor shall locate all Hazardous Substances that exist at the Job Site (including hazardous building material, contents of USTs and ASTs, PCBs, asbestos, and all other Hazardous Substances), determine what each Hazardous Substance is (i.e., confirm waste characterization), and properly and safely abate, remove, handle, store, transport, and dispose of each Hazardous Substance (and maintain full records of each such step) (all of the foregoing, Abate). All such Abatement for a structure shall be completed before any demolition of that structure except to the extent that it is not practical to do so and Abatement after commencement of demolition can be done properly and safely.

Contractor shall perform all Work in a manner so as to not impact (or otherwise put at risk) the normal operations of the facilities at the Cane Run Generating Station Site, including but not limited to, those of the switching station, transmission lines, and gas turbine generating units. Without limiting the foregoing, Contractor shall avoid causing excessive vibrations. Contractor shall

complete all demolition above each elevation of a structure before the supporting members on the lower level of that structure are disturbed. Contractor shall not commence demolition on any structures that are clad in whole or in part with transite (or other Hazardous Substance containing) panels until such panels are abated.
Certain structures on the Job Site (the east basement wall of the power block structure) are integral to the Ohio River flood protection system. Contractor shall perform the Work so that such Work in no way lessens the effectiveness of the existing levee or the Ohio River flood protection system.

2.1 General Site Requirements

2.1.1 Dust Control:
Contractor shall perform Dust Control as a component of Demolition.

Contractor shall perform dust control as specified in Technical Specifications Division 2 –Site Work-Section 02507 Dust Control.

Contractor shall perform Dust Control in Work Limits as designated in the project drawings.

For all Dust Control within the Work, Contractor understands and acknowledges that controlling dust is of critical importance. In that regard, Contractor shall perform the Work (i) in compliance with all applicable laws (including, without limitation, Federal, state and local statutes, ordinances, regulations, etc.) and with the Owner's dust control plan(s) (as filed with the Air Pollution Control District of Metro Louisville, Kentucky or other applicable agency) and air permit(s) as such plans and permits are in effect, modified, amended, supplemented, or otherwise modified from time to time (ii) in a manner such that no visible dust will leave the areas in which Work is performed (either while the Work is being performed or thereafter), and (iii) in compliance with Ash Pond Closure Technical Specifications Division 2 – Site Work- Section 02507 – Dust Control - 3.4.2. The foregoing requirements are cumulative and compliance with one of the requirements shall not relieve Contractor of its obligation to comply with all of the other requirements. If Contractor believes any of the requirements are in conflict (i.e., it cannot comply with one requirement without violating another), Contractor shall immediately notify Owner and thereafter comply with Owner's directives on complying with the requirements. Without in any way limiting Owner's other remedies available for any breach of Contractor's obligations under this paragraph (or any other provision of this Contract), Contractor shall indemnify and hold Owner harmless from any and all damage, loss, claim, expense, demand, suit, notice of violation, liability, penalty, fine, or forfeiture of every kind or nature, including but not limited to the attorney costs (e.g., salary and burden for in-house attorneys and fees for outside counsel) and expenses and other costs and expenses of defending against the foregoing and payment of any settlement or judgment therefore, by reason of any breach or alleged breach of Contractor's obligations under this paragraph.

Dust control shall include truck tire wash station, watering of work areas, and surrounding access roads.

2.1.1 Storm Water Control:

Contractor shall establish and maintain all sediment controls and stormwater management, including ditches, silt fence, check dams, gravel, revegetation of disturbed areas and any other necessary controls required in these Specifications and Drawings, and to perform the Work.

Contractor shall develop a project-specific Best Management Practices (BMP) Plan in accordance with the Appendix "Construction Best Management Practices (BMP) Plans".

2.1.2 Meetings and Progress Reports:

Refer to the Agreement and these Technical Specifications.

2.1.3 Maintenance of Access Roads:

Maintenance of construction access roads is incidental to the Work.

2.2 Asbestos, Lead Abatement, PCBs and other Regulated Materials

Contractor shall remove all asbestos containing and other regulated materials. The survey of regulated materials and associated drawings are found in the reference set of documents.

The Work shall include but not be limited to the following:

a. Contractor is responsible for following proper abatement industry practice.

b. Contractor is responsible for locating regulated materials and performing their own abatement in their work area.

c. Contractor shall provide landfill manifest documentation for any and all asbestos and/or lead that is removed from this site.

d. A hazardous materials survey was performed and is provided in the reference set of documents. Contractor to review the survey data and known ACM locations, ascertain field conditions and extent of materials requiring removal. The survey is not all encompassing and Contractor is responsible for identifying and remediating the hazardous material types identified.

e. Electrical Transformers throughout the Job Site are to be removed and properly disposed of. A schedule of transformers with known information is provided in the reference set of documents. The contractor shall include the dismounting and staging of all transformers or other oil bearing electrical components in their base price for the project. The transportation and disposal of electrical equipment and associated dielectric fluids will be based on a unit price.

2.3 Equipment Demolition

The Work set forth in this Equipment Demolition shall be in accordance with Drawings CR0-C-10001-C-001 thru CR0-P-00001-PH-004.

The Work shall include but not be limited to demolition of the following:

a. Demolish CR6 SPP (Sludge Processing Plant), filter building, tanks, and stack out conveyor down to concrete. (Scope Item 2) Remove equipment, piping, etc. and recycle and dispose of as appropriate. The small concrete support pedestals shall be cut down even with the floor. Fill the basement equipment corridor and room according to specification section 31 23 01.

b. Demo Lime Storage Tanks down to concrete pad. (Scope Item 3). Remove all equipment, storage structures, piping, etc. in this area and dispose of/recycle as appropriate.

c. Demo Reactant Supply Building down to concrete pad. (Scope Item 4) Remove all equipment, piping, etc. and dispose of/recycle as appropriate.

d. Demo Reactant Supply Switchgear down to concrete pad. (Scope Item 5) Remove Electrical and other equipment and dispose/recycle as appropriate.

e. Demo Emulsified Sulfur equipment and building down to concrete pad. (Scope Item 6).

f. CR4 FGD - demo booster fans, ductwork, modules, piping, recycle pumps, thickener, flocculent feed, reaction tank, mist eliminator wash pumps, and structural steel down to top of concrete. (Scope Item 10). Remove equipment from underground equipment rooms and fill these areas and the flocculant tanks according to specification section 31 23 01.

g. CR5 FGD - demo booster fans, ductwork, modules, piping, reaction tanks, recycle pumps, thickener, thickener return pumps, mist eliminator wash pumps, structural steel down to top of concrete. (Scope Item 11). The tank bottom forms an inverted conical depression. Contractor shall fill this depression to surrounding grade according to specification section 31 23 01.

h. CR6 FGD - demo booster fans, ductwork, modules, piping, reaction tank, recycle pumps, thickener, return tank and pumps, structural steel down to top of concrete and fill pit in according to specification section 31 23 01. (Scope Item 12).

i. Demo CR FGD equipment house down to concrete pad. (Scope Item 13)

j. Remove and Recycle transformers throughout the site (Scope Item 14). Contractor shall use LG&E preapproved transformer demolition and disposal firms to remove the transformers and dispose of their remaining contents and appurtenances. Four transformers are known to contain PCBs above 50PPM. See complete Transformer Data spreadshseet for details.

Commented [KRM1]: Recycle? Is that the right term?

k. Demolish Powerhouse Building including Annex, Office and Units 1 through 6. (Scope Item 41). Preserve basement floor and north, south and east walls according to levee modifications details. Abandon piping, conduit and duck banks in the remaining building foundation walls per Specification section 22 01 00 below elevation 461.00. Fill the ignition oil enclosures along the east wall with flowable fill. Use flowable fill to bring all depressions, sumps, drains, trenches, etc. up to elevation 427.00 (basement floor elevation) in the basement of the main plant.

l. Demo all stacks and ducts. (Scope Item 42)

m. Demo Warehouse 17 down to concrete pad. (Scope Item 15)

n. Demo Warehouse 19 down to concrete pad. (Scope Item 16)

o. Demo water trailers, tank, electrical and interconnecting piping and all miscellaneous equipment to slab. (Scope Item 38)

p. Demo FGD Maintenance Warehouse down to concrete pad. (Scope Item 18)

q. Demo Coal Yard Equipment Shed. (Scope Item 22).

r. Demo Coal Yard Shaker House and Fill hopper. Fill underground spaces in accordance with specification section 31 23 01. (Scope Item 23)

s. Demo Coal Yard Conveyors. Fill underground spaces in accordance with specification section 31 23 01. (Scope Item 24)

t. Demo Coal Yard Crusher House. Fill underground spaces in accordance with specification section 31 23 01. (Scope Item 25)

u. Demo Coal Yard Drive House. (Scope Item 26)

v. Demo Coal Yard Engine House. Fill underground spaces in accordance with specification section 31 23 01. (Scope Item 27)

w. Demo North Fly Ash Bin, and Transfer house equipment, structure, and piping. (Scope Item 29).

x. Demo Slurry Barge Unloading Structure and remove catwalk (Scope Item 31) to two feet below existing ground line and grout remaining terminations.

y. Demo Valve pit near Slurry Barge Unloading Structure. (Scope Item 32). Remove piping and equipment, grout pipe terminations and fill the pit in accordance with specification section 31 23 01.

z. Demo coal yard conveyor junction house. (Scope Item 37).

aa. Remove High Tension Transmission Lines and support towers. (Scope Item 45)

bb. Abandon underground structures and void spaces as described in the specifications 31 23 01. Fill underground voids with flowable or granular fill material. (Scope Item 46) cc. Demolish Circulating Water Steel Pipe (Scope Item (47)) on the west side of the plant foundation back to the joint with concrete piping. Plug and grout concrete piping to be abandoned in place.

dd. Abandon discharge tunnel weir structures (Scope Item (48)) on the west side of the plant foundation per specification section 31 23 01. Plug and grout ten linear feet of discharge tunnel that leads to the river.

ee. Abandon Breaker House 1 and 2 and Tunnel 1 and 2 (Scope Item (49)) per specification section 31 12 01.

The Work shall include but not be limited to protection of the following:

a. CR FGD control room – east of Unit 4. Protect structure and all appurtenances to maintain operation.

b. Clearwell on the northeast corner of the site.

c. Substation #1 and #2 as indicated on the site plan.

d. Switchyard between substation #1 and #2

e. Environmental Storage Building

f. River screenhouse

g. All barge cells, dolphins, etc.

h. Gas Meter House

i. Aerial Utilities as indicated on the plans

j. Below ground conduit and utilities as indicated on the plans.

k. Railroad track not owned by LG&E as indicated on the plans.

2.4 Building Penetrations and Fill

Multiple tunnels, equipment rooms, underground concrete tanks and stairways require filling to grade after equipment is removed. The restoration areas are indicated in the plans and further described in the specifications.

2.4.1 Fill:

a. Contractor shall place fill and/or flowable fill, per the Technical Specifications 31 23 01. The areas requiring subsurface fill are indicated on the drawings. If any material is dumped in unauthorized areas or outside designated limits, Contractor shall remove the material and restore the area to the condition of the adjacent undisturbed areas.

2.5 Option Pricing

Not Applicable

PART 3 SPECIFICATIONS, EXHIBITS AND DRAWINGS

All Work shall be performed in strict accordance with the following specifications, exhibits and drawings which are incorporated herein by reference.

3.1 Specifications

SPECIFICATIONS LIST TABLE	
Spec Section	Specification Title & Date
01 11 00	SUMMARY OF WORK
01 14 00	WORK RESTRICTIONS 08/04/2016
01 33 00	SUBMITTAL PROCEDURES 08/04/2016
01 35 26	SAFETY REQUIREMENTS 08/04/2016
01 45 00	QUALITY CONTROL 08/04/2016
01 50 00	TEMPORARY CONSTRUCTION FACILITIES AND CONTROLS 08/04/2016
01 57 19 00 20	TEMPORARY ENVIRONMENTAL CONTROLS 08/04/2016
01 57 23	TEMPORARY STORM WATER POLLUTION CONTROL 08/04/2016
01 74 19	DEMOLITION WASTE MANAGEMENT 08/04/2016
02 41 00	DEMOLITION AND DECONSTRUCTION 08/04/2016
02 66 00	SELECT FILL AND TOPSOIL FOR CAP COVER 08/04/2016
02 81 00	WASTE TRANSPORTATION AND DISPOSAL 08/04/2016
02 82 14 00 10	ASBESTOS ABATEMENT 08/04/2016
02 83 13 00 20	LEAD IN CONSTRUCTION 08/04/2016
02 84 16	UNIVERSAL WASTE 08/04/2016
02 84 33	PCB OILS 08/04/2016
05 40 00	COLD FORM METAL FRAMING 08/04/2016
07 42 13	METAL WALL PANELS 08/04/2016
07 92 00	JOINT SEALANT 08/04/2016
22 01 00	ABANDONMENT OF PIPING AND CONDUIT 08/04/2016
31 23 01	ABANDONMENT OF FOUNDATIONS 08/04/2016

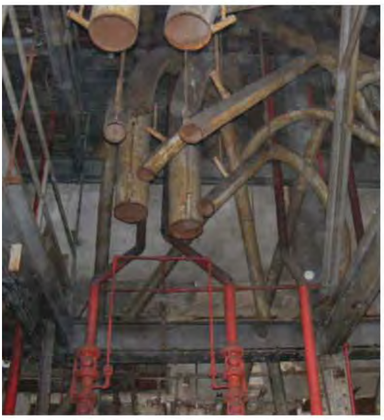
Commented [KRM2]: Too be revised.

3.2 Drawings

Sheet Number	Sheet Title	Sheet Description
1	PR0-C-10001-C-001	COVER SHEET
2	PR0-C-10002-C-002	INDEX SHEET
3	PR0-C-10003-C-003	LEGEND & ABBREVIATIONS
4	PR0-C-10004-C-004	GENERAL NOTES
5	PR0-C-10005-C-005	SCOPE OF WORK
6	PR0-C-10006-C-006	SCOPE OF WORK
7	PR0-C-10007-C-007	SCOPE OF WORK
8	PR0-C-10008-C-008	PRECIPITATOR DUCTWORK UNIT 4
9	PR0-C-10009-C-009	PRECIPITATOR DUCTWORK UNITS 5 & 6
10	PR0-C-10010-C-010	PRECIPITATOR DUCTWORK UNIT 5
11	PR0-C-10011-C-011	PRECIPITATOR DUCTWORK UNIT 6
12	PR0-C-10012-C-012	STACK OPENING TEMPORARY CLOSURE
13	PR0-C-10013-C-013	BARGE DOCK DEMOLITION
14	PR0-S-00001-HA-001	WALL PANEL CLOSURE DETAILS
15	PR0-S-00001-HA-002	PIPE AND CONDUIT DEMOLITION
16	PR0-S-00001-HA-003	DUCT BANK DEMOLITION OPTIONS
17	PRO-P-00001-PH-001	PHOTOGRAPHIC LOG SHEET 1
18	PRO-P-00001-PH-002	PHOTOGRAPHIC LOG SHEET 2
19	PRO-P-00001-PH-003	PHOTOGRAPHIC LOG SHEET 3
20	PRO-P-00001-PH-004	PHOTOGRAPHIC LOG SHEET 4

PPL companies

Canal Station
Conceptual Phase Study
Demolition with Clean Fill Option



Prepared by:
AMEC Environment & Infrastructure, Inc.
11003 Bluegrass Parkway, Suite 690
Louisville, Kentucky 40299

amec.com

June 18, 2013

Mr. Greg Jones, PE
LG&E-KU Services Company
Project Engineering
820 West Broadway
Louisville, KY 40202

Re: Canal Station
Conceptual Phase Study - Demolition with Clean Fill Option
Louisville, KY

Dear Mr. Jones:

The attached *Conceptual Phase Study - Demolition with Clean Fill Option* presents AMEC Environment and Infrastructure, Inc. (AMEC's) findings, cost estimates, preliminary risk evaluation, and recommendations for final disposition of the Canal Station former coal powerhouse complex located at 2005 Northwestern Parkway in Louisville, Jefferson County, Kentucky.

We appreciate the opportunity to provide engineering and environmental support services to LG&E-KU on this project. If you have any questions or require further clarification, please feel free to contact Wade Turner or Douglas Lane at (502) 267-0700.

Sincerely,

J. Wade Turner, PE
Client Manager

Douglas Lane, PG
Project Manager

Enclosures

/cf

TABLE OF CONTENTS

SECTION **PAGE NO.**

APPENDICES

1.0 PROJECT BACKGROUND

Louisville Gas and Electric Company (LG&E) commissioned AMEC Environment & Infrastructure, Inc. (AMEC) to perform the *Canal Generating Station-Demolition Consulting-Conceptual Phase Study.* The final Request for Proposal (RFP) dated January 14, 2013 identified the following key objectives of the project:

1) Prepare a conceptual project plan(s),
2) Perform or subcontract vital testing/ monitoring for assessment needed to perform conceptual development, and
3) Prepare estimate(s) for remedial and/or removal work as described in the conceptual project plan to secure the sites against physical and environmental liabilities while minimizing operating and maintenance costs.

AMEC examined several feasible options for disposition of the former coal powerhouse complex at Canal Station, including removal of hazardous building materials (HBMs), along with various scenarios of demolition and on-site vs. off-site disposal of debris. AMEC presented a draft *Preliminary Concepts Report* on April 14, 2013 which addressed the aforementioned objectives. The final *Preliminary Concepts Report,* which includes comments from LG&E is included in **Appendix 1**. The alternative project paths considered included four main options:

1. **Mothball Structures:** Physical hazards would be addressed, but the structures would remain in place. This option would reduce risks associated with hazardous materials and worker safety, but would not eliminate risks associated with structural systems and trespassers.
2. **Demolition with On-site Disposal:** The HBMs would be removed and deconstruction would include removal of all structures to a depth of 6 feet below the ground surface. Non-hazardous, non-salvageable building materials such as clean masonry and concrete materials would be crushed on-site and used as backfill to the maximum extent feasible.
3. **Demolition with Clean Fill:** HBMs would be removed and deconstruction of the structures would include complete removal and off-site disposal and/or salvage of all building materials, with the exception of foundation pilings. Clean, engineered backfill would be used to establish the final grade and meet USACE Flood Protection System (FPS), or floodwall, design specifications. The screen house and intake structures would be demolished to the higher elevation of the Ohio River normal pool or current water level at the time of demolition. No underwater deconstruction or substantial use of sheet piling to enable underwater work has been included in the cost estimates.
4. **Demolition with Residual Landfill:** Demolition of structures would be accomplished to approximately six (6) feet below ground surface (bgs). Asbestos containing material (ACM) would be abated above-grade only and would be disposed in the basement area of the structure. A residual landfill permit with long-term monitoring would be required.

Based on the draft Preliminary Concepts Report, LG&E has chosen to pursue **Option 3: Demolition with Clean Fill** because it provides the widest possible range of property reuse opportunities. AMEC estimated an order-of-magnitude cost of $7.3 million would be required to achieve the aforementioned objectives for Option 3. This final report focuses on health & safety aspects (Section 3.0), environmental aspects (Section 4.0), flood protection system aspects

(Section 5.0), deconstruction aspects (Section 6.0), and costs (**Appendix 4**) for Option 3. A more detailed discussion of the conceptual phase study of various options is provided below.

For the *Canal Generating Station-Demolition Consulting-Conceptual Phase Study*, AMEC was tasked to evaluate only the inactive portion of the property on the south side of the Louisville Metro Flood Protection System (FPS) floodwall, also known as the former coal powerhouse complex; the active operating areas on the east side of the floodwall (electric substation and storage yard currently leased to a subcontractor) were not included in the study. The final Preliminary Concepts Report presents an evaluation of key project aspects and an order-of-magnitude cost estimate for the four (4) above-referenced options. AMEC evaluated the following key aspects or issues which significantly influence project strategy regardless of the project path selected:

1. **Louisville Metro Flood Protection System (FPS).** Any action or option which results in alteration of the existing Flood Protection System must be approved through the federal (Section 408) permitting process to meet the current design standards of the U.S. Army Corps of Engineers (USACE) and any additional standards imposed by the owner, Louisville and Jefferson County Metropolitan Sewer District (MSD).
2. **Environmental, Health, and Safety Aspects,** including physical hazards, asbestos, lead-based paint, and other hazardous building materials require careful management to minimize risks to site workers and the public while complying with appropriate regulatory permits and agency requirements to achieve a final, clean closure of the property. Current conditions of the site present safety and environmental risks associated with falling objects, deteriorated structures, potential trespassers, and the potential for environmental releases.
3. **Deconstruction** of the structures will include careful sequencing to achieve safe removal and off-site disposal and/or salvage of building materials. The screen house structures will be demolished to the higher of the Ohio River normal pool or current water level at the time of demolition. No underwater deconstruction has been included in the cost estimates. The backfill used to return the site to grade must meet FPS design specifications.

The RFP required submittal of draft and final reports which include the following specific elements (*italics*). Each scope item is further addressed in detail in the below-referenced sections of this report:

- *Assessment of environmental issues* (Section 4.0)
- *Assessments of current site conditions and likely risks (*Section 2.0, Appendix 1)
- *Assessments of continuing liability* (Appendix 1)
- *Assessments of future regulations that could impact the site* (Appendix 1)
- *Other assessments as proposed by Contractor in the bid. AMEC reviewed existing hazardous materials assessments and conducted additional asbestos and lead-based paint sampling to better identify the nature and extent of those materials* (Appendix 6).
- *Testing or monitoring processes related to environmental issues that are proposed by Contractor and agreed to with LG&E during the bid process. The contractor shall specify what testing will be necessary during the conceptual phase development and during the engineering/construction phase* (Appendix 6).
- *Appropriate remediation for any hazardous materials* (Section 4.0, Appendix 1).

- *Assessment of impacts to adjoining neighborhoods, properties, etc. from things such as demolition, impact on traffic patterns* (Section 4.0).
- *Identify and address material and equipment that may have salvage value as well as disposal issues* (Section 6.0).
- *Identify specific local, state, federal agencies and other stakeholder groups that LG&E will need to interact with as part of this project, such as the US Army Corps of Engineers, the EPA, Kentucky Division of Water Management, etc. Potentially interact with these agencies identified as required to develop a concept* (Appendix 5).
- *Assess and prepare a list of permits, inclusive of schedule requirements for the permits, required to implement ultimate plan* (Section 4.0, Appendix 5).
- *Identify alternative project paths* (Appendix 1).

The order-of-magnitude costs were developed for the HBM abatement, deconstruction, and FPS concerns according to the four options described above. These costs do not include:

- Removal or abandonment of structures below the Ohio River water level, other than directly beneath current floodwall structures.

The final Preliminary Concepts Report (**Appendix 1**) includes order-of-magnitude cost estimates for each option. Estimated order-of-magnitude costs may vary significantly from the actual costs dependant on a number of factors including competition, disposal, season, insurance, salvage material and metal values, and finalized scope of work, etc. These limitations should be considered during budget formulation.

Additional study is recommended to further define the scope and costs associated with abatement of HBMs, FPS alterations, deconstruction and salvage of building materials, as well as to facilitate the project schedule by completing certain preliminary planning tasks. A list of implementation phase planning activities and associated estimated costs is included in **Appendix 4**.

2.0 SITE DESCRIPTION

Canal Station consists of approximately 15 acres located in an industrial/commercial/residential area at 2005 Northwestern Parkway in Louisville, Kentucky. It consists of a former coal powerhouse complex, an active switch station, and leased space along and on the south bank of the approach canal to the Ohio River lock and dam (**Figure 1**). The property includes the Louisville Metro Flood Protection System (FPS) floodwall (**Figure 2A**).

The former powerhouse complex was developed in the 1880s, and included an approximately 400-foot by 400-foot building which housed four (4) coal-fired generating units, a screen house water intake structure, and sub-surface river intake and discharge tunnels. The east wall of the powerhouse structure is integral to the floodwall (**see Figures 2A, 2B, and 2C and discussion in Section 5.0**).

The powerhouse complex has been inactive since the 1970s and contains various hazardous building materials (HBMs), including asbestos and lead-based paints (**see Section 4.0**). The structural and mechanical systems are in a continual state of decline and the structures present numerous risks to LG&E. The powerhouse structure is integral to the floodwall, as detailed in Section 5 of this report and on **Figures 2A/2B/2C, 3A/3B, and 4A/4B**.The western portion of the site is currently an active switching station with a leased storage yard for an LG&E subcontractor. Current plans are to continue the use of the switching station and storage yard.

3.0 HEALTH & SAFETY

Key health and safety aspects such as physical hazards, asbestos, lead, and other HBMs require careful management to minimize risks to site workers and the public while complying with appropriate regulatory provisions and agency requirements.

Physical hazards, including deteriorated metal grating and plates in floor openings, mezzanines, and stairs, falling brick veneer & broken glass, will need to be addressed by installing covers/rails for floor openings, barricades near falling object hazards, etc. Additionally, appropriate site security and access control measures should be employed to reduce exposure for site workers and potential trespassers.

HBMs, including asbestos and lead-based paints are in a significantly-deteriorated condition, with visible releases of asbestos containing materials and paint chips on the floors of the structure, particularly on the boiler side. Access to the site currently requires use of a respirator and protective clothing due to these hazards. Exposure to airborne HBMs is a significant concern.

Other health and safety concerns for abatement and deconstruction projects include, but are not limited to: exposure to heat/cold, bird droppings, and wet conditions; working at heights; heavy equipment operation; electrical work; hot work; and portable powered tools.

Throughout the abatement and deconstruction phases of the project, strict safety rules, including those addressed in LG&E’s Passport Safety Program should be employed to minimize the exposure of workers to the site hazards. An approved site-specific health and safety plan should be implemented by all contractors and site workers.

4.0 ENVIRONMENTAL

Key environmental aspects include asbestos, lead, protection of the natural environment, and others. Complying with appropriate regulatory provisions and agency requirements is of paramount importance. Anticipated environmental permits and anticipated timelines are listed in **Appendix 5**.

Asbestos is the most significant HBM present in the powerhouse complex structures, confirmed by previous documentation and additional limited sampling by AMEC. The interior of the main powerhouse structure is currently managed as an asbestos area due to uncontrolled releases of fibers, requiring employees to use personal protective equipment to perform routine maintenance tasks. The current EPA regulation for the removal of asbestos in buildings, the National Emission Standard for Hazardous Air Pollutants (NESHAP, 40 CFR 61, Subpart M) requires regulated ACMs be properly removed prior to performing renovation and demolition activities which would disturb them. The Louisville Metro Air Pollution Control District (APCD) regulates asbestos activities through the issuance of permits and oversight of abatement activities. A licensed Asbestos Designer should develop ACM abatement specifications to address the scope of removal work, regulatory requirements, notification procedures, air sampling requirements and other pertinent information.

*A*sbestos removal should be monitored to ensure no asbestos is released into ambient air. During enclosed asbestos removals, a licensed independent or 3rd party consultant should perform monitoring during the abatement and perform clearance air testing prior to the removal of the containment/enclosure barriers. If concealed ACM is later observed during demolition activities as access is gained to previously inaccessible areas, it will be necessary to investigate and collect bulk samples of each potential ACM in order to confirm the presence or absence of asbestos content. Inaccessible locations include: inside wall cavities or other finishing/ structural/architectural materials; above fixed ceiling systems; inside mechanical systems, boilers, ducts, equipment, or manufacturing/production equipment (e.g. air handling units, ductwork, etc.); and areas that were previously unsafe to access (including excessive heights, confined spaces, etc.).

AMEC recommends a more comprehensive inventory of hazardous materials be completed to confirm the full scope of environmental remediation and associated costs. Potential additional hazardous materials and environmental conditions which should be addressed include:

- Lead-based paint (LBP) in structural and equipment coating systems.
- Mercury-containing equipment such as switches, manometers, etc.
- Polychlorinated biphenyls (PCBs) in ballasts, equipment, and elastomeric materials. The EPA generally regulates the handling and disposal of PCBs in building materials above 50 mg/kg.
- Radioactive sources.
- Chlorofluorocarbon (CFC) containing equipment; refrigeration equipment, canisters, etc.
- Duct, trench, pit, and pipe residues; dusts, liquids, etc.
- Contaminated soils; associated with spills, underground petroleum tanks, etc.
- Miscellaneous containers of unknown chemicals and hazardous substances.
- Characterize concrete and masonry for salvage and off-site reuse in lieu of disposal.
- Potential buried fly and/or boiler ash on the site.

HBMs should be identified, characterized, removed and disposed off-site in accordance with local, state, and federal regulations. AMEC estimated quantities of asbestos and other HBMs to develop the order-of-magnitude cost estimates for abatement (**Appendix 4**) based on a brief site examination, limited sampling during the walkthrough, and a review of existing documentation. A more extensive evaluation of HBMs and HBM quantities could further refine the cost estimate.

Depending on the final FPS alteration permit and/or funding mechanisms, a National Environmental Policy Act (NEPA) review of certain aspects of the project may be required. This could include preparation of an Environmental Assessment or other NEPA document, including examining the historical value of the property, noise impacts, air quality impacts, water quality impacts, etc.

The estimated order-of-magnitude costs and assumptions for implementation of additional environmental planning, permitting, and hazardous materials assessments are also presented in **Appendix 4**.

5.0 FLOOD PROTECTION SYSTEM

The Flood Protection System (FPS) on the Canal Generating Station property consists of USACE-designed and constructed pile-supported concrete floodwalls attached to the east elevation of the main powerhouse building at the northeast and southeast corners (**Figure 2A**). The former powerhouse is situated on the dry-side of the floodwall; the east basement wall actually constitutes a section of the floodwall. The FPS in this area provides flood protection for the industrial, commercial, and residential areas to the south known as the Portland Historic District, including LG&E's operating electrical substation on the property. Because portions of the powerhouse complex are integral to the floodwall, any deconstruction of structures affecting the integrity of the floodwall must be approved through the USACE Section 408 permitting process. Therefore, the Demolition with Clean Fill Option provides for installation of a new section of floodwall to the east/northeast of the main powerhouse structure prior to structural demolition affecting the integrity of the basement wall.

The foundation system of the east elevation of the building was retrofitted in the 1940's with exterior sheet piling to rock and concrete infill to an elevation of 465 feet, mean sea level (msl) as a flood protection measure by LG&E. The floodwall in this area of the FPS was constructed in the 1950's and the powerhouse structure foundation was incorporated (and grandfathered) into the FPS at that time. The floodwall is approximately 9 feet tall with a top of wall elevation at 464 feet, msl. The floodwall enters the property at an earthen levee (MSD designated Station 204 + 61) located along the east property boundary and ends at the southeast corner of the existing building (Station 210 + 04), and incorporates the east wall of the structure basement from floodwall station 210 + 04 to floodwall station 212 + 65. A second floodwall section begins at the northeast corner of the building (Station 212 + 65) and extends to the property boundary at the northwest corner of the property (Station 226+00). **Figure 2A** shows the floodwall configuration on the subject property. The floodwall is also equipped with an operable floodgate opening to access the exterior of the property at Station 209 +21. **Figures 2A, 2B, and 2C** provide plan view layout, design and right-of-way (ROW) details of the existing floodwall system. **Figures 3A/3B and Figures 4A/4B** provide cross-sectional views of the powerhouse complex and floodwall structures, respectively.

The floodwall (powerhouse structure excepted) is owned, operated, and maintained by MSD with established right-of-way (ROW) easements. LG&E has been responsible for maintenance of the powerhouse structure section of the floodwall. According to information provided by MSD, the floodwall on the Canal Station property does not have outstanding issues based on USACE Periodic Inspection Reports (PIRs), however, during a meeting with the USACE and MSD, the condition of the metal sheet piling was questioned based on the age of the structure. At the time of AMEC's site inspection, the floodwall appeared to be in generally good condition. At present, MSD and the USACE are reportedly nearing an agreement for the USACE to perform a FEMA-mandated floodwall certification (44 CFR 65.10) of the entire 26.5+ mile flood protection system around the north and west sides of Louisville Metro. AMEC estimates this process will require a minimum of two years to complete, but should not significantly affect approval of any proposed LG&E alteration plans that meet current USACE design criteria.

Two floodwall alterations to the system have been completed on the Canal Station property since 2009. Additionally, levee reinforcement work beneath the floodwall was done to block off the intake/discharge tunnels and a 30-inch de-icing pipe located above the intake tunnels based on USACE concerns that water could breach the levee thru these structures during a flood event and that the floodwall stability could be compromised if the tunnels collapsed. **Figure 2B** shows the approximate locations of the intake/discharge tunnels. These alterations and the permanent closure of Gatewell #56 (Station 217 + 70) located near the floodwall above the discharge tunnel were completed in 2009. A gate with a rail entrance at the northeast corner of the east elevation (Canal Station 22nd Street Gate) was permanently closed in 2010 with USACE and MSD approval.

During a meeting with the USACE and MSD at the USACE office, the USACE and MSD indicated proposed floodwall alteration plans would require their input and concurrence. Furthermore, future demolition plans for the main building and/or intake structures, combined with a proposed new section of floodwall, would need to comply with hydrology/hydraulics modeling and slope stability requirements of the current USACE flood protection system design criteria. The USACE also indicated any proposed alterations to the floodwall should include abandonment of penetrations or conduits directly underneath the proposed floodwall section if the powerhouse structure were to be demolished. For example, should a replacement floodwall section be proposed for installation from approximately Station 205 + 00 to Station 213 + 00, the subsurface structures, including intake, discharge, and de-ice pipe etc located directly beneath the proposed floodwall must be properly abandoned.

AMEC considers floodwall alteration permit approvals from MSD and the USACE critical to implementation of the deconstruction of the Canal Station structures. In the meeting at the USACE office, USACE indicated that a new flood wall of this magnitude (approximately 400 feet of new floodwall) is likely to be considered a minor modification and could be approved at the local level, significantly reducing the time required to obtain a permit-to-construct. An engineering evaluation and hydraulic modeling of any planned floodwall alteration is the first step to developing the Section 408 permit application.

6.0 DECONSTRUCTION

The Canal Station powerhouse complex structures consist mainly of steel beam construction, with brick, metal sheeting, and transite facades, built-up roofs, and concrete reinforcements. Below-grade or basement walls and floor slabs are steel-reinforced concrete. Slabs and walls rest on footers, grade beams and vertical pilings. Process equipment, including boilers, tanks, piping, pumps, etc. are mounted on steel and concrete structures throughout the structures, most of which will be removed for salvage during or following asbestos abatement activities. **Figure 3A & 3B** provide cross-section details of the main powerhouse complex structures.

The Demolition with Clean Fill Option provides for complete removal and off-site disposition of the main building structures, down to and including slabs, footings and grade beams. Vertical auger cast piles or other driven pilings will remain. Subsurface structures associated with the water intake and effluent structures below the water table are also assumed to remain, other than any alterations needed to assure integrity of the current or new sections of the floodwall. These structures are not likely to affect future site development other than new port-related facilities, contain no known HBMs, and are not expected to be a hazard to navigation. If future development plans include waterfront structures, then deconstruction of those structures and resultant costs could be addressed at that time.

Conventional deconstruction, or demolition, with continual separation of salvageable materials will be the most cost effective method of removing these structures. AMEC understands the main structural components cannot be dismantled until the floodwall alteration is complete, though many site activities, including utility work, mobilization, site security, and removal of HBMs that don't affect integrity of the structure may proceed.

The project is expected to follow the below typical sequence, however, some tasks may be completed simultaneously and may be subject to change based on floodwall alteration permit requirements:

- Work Plan Development, including approval of designated disposal/recycling targets, HBM abatement plans, permitting, grading, Site-specific Health & Safety Plan, etc.
- Mobilization and set up of site security
- Make site and structures safe and secure for worker access and deconstruction
- Implement erosion control plan
- Verify energy sources, utilities, and pipelines, etc.
- Develop and implement utility capping plan and lockout/tagout (LOTO) plan, as required
- Removal of universal wastes
- Removal of asbestos and lead
- Equipment and scrap recovery
- Remove structure through mechanical means
- Process steel, segregate masonry/concrete from other streams
- Remove subsurface structures to top of pilings, as limited by the structure, groundwater, or river water levels.
- Backfill subsurface with approved clean fill to final grade and restore surface cover per plan
- Demobilize

Scrap metal value recovery return for Canal Station will likely be substantial, though equipment values have either already been realized or are likely to be low due to the relative age of the facility. Our estimate utilized a conservative value based on a limited quantity take-off from the brief site visit. The market value used for our cost estimate was $200 per ton. Actual returns will depend on market conditions and project timing. Implementation phase planning should include a more detailed analysis and quantity take-off of salvage/scrap materials in order to better evaluate contractor's bids and their proposed credit scheme for scrap values. Copper scrap recovery was not included in the initial estimate, but may also be substantial. Steam turbines may also be sold for scrap.

A comprehensive specification for this project would include the necessary data to allow contractors to accurately price the hazardous material handling, asbestos removal, structure demolition, and site restoration aspects of the project. This includes assembling available construction or as-built drawings, hazardous/asbestos surveys, geotechnical, floodwall profiles, specifications, final grading plan, SWPPP and the owner's preferences for the disposition/reuse of waste streams. It is preferable to use performance-based specifications on large demolition projects to allow the Contractor to provide creative solutions to project challenges, but still allow the owner to be specific and prescriptive about elements of work or requirements of high interest/risk.

Given the significant quantities of HBMs, primarily asbestos and lead-based paint, AMEC recommends that HBM abatement, structural demolition, and site restoration be contracted under one general Contractor, if possible. The general contractor can also be responsible for key permitting activities, subject to LG&E review and approval. This also allows the bidders to determine exact sequencing (as allowed by permit issuance). Creating a contract that balances the risks of incidents and poor performance with effective control of the work, while recovering the maximum value of assets, can produce a successful outcome. The selection of qualified bidders should at a minimum reflect the Owner's values of Safety, Compliance, Quality and financial responsibility.

AMEC has provided an estimate of demolition costs consistent with other similar projects for Option 3 Demolition with Clean Fill (see detailed cost estimate in **Appendix 4**). Option 3 is the most conservative deconstruction option and provides for the widest possible range of site reuse options. The extent of demolition has been defined in the various possible options (see *Preliminary Concepts Report* in **Appendix 1**) relative to disposition of subsurface structures, concrete/ masonry disposal vs. reuse, backfill materials, and other considerations.

APPENDIX 1

PRELIMINARY CONCEPTS REPORT

CANAL STATION

RETIRED ASSET DISPOSITION

PRELIMINARY CONCEPTS REPORT

Prepared by:

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May 6, 2013

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CLIENT:
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CLIENT LOGO:
LG&E

DRAWN BY: CAK
CHK'D BY:
DATUM: NAD83
PROJECTION: UTM 16N
SCALE: AS SHOWN
DATE: 5/02/2013

PROJECT:
CANAL STATION
LOUISVILLE GAS & ELECTRIC
LOUISVILLE, KY

Legend
Floodgate
Levee
Floodwall
LG&E Property

FIGURE
1

OVERVIEW

Background

- Flood Protection System (FPS) flood wall integral and/or adjacent to structures
- Active switching station & contractor laydown yard
- Former coal boiler units (2) with partial chimneys
- One screenhouse; Intake/Discharge tunnels
- Flood wall incorporated into east wall of building
- Integrity of flood wall on north side building of concern to USACE
- Purported former city landfill on property
- Mixed commercial/industrial area with adjacent residential

Site Conditions

- Primary Hazardous Building Materials (HBM) asbestos and lead-based paint (LBP) in poor condition
- Other HBM: PCBs, mercury, tank/pipe residues, etc.
- Ongoing monitoring and maintenance of basement sumps
- Interior access difficult - requires respirator and protective suit
- Structural hazards
  - Significant corrosion on major structural members; roof leaks
  - Steel decking / grating / stairs / mezzanines – potentially unsafe
- Evidence of periodic trespassing

Options

1. **Mothball**
   - Traditional asbestos & other HBM abatement & disposal off-site
   - "Cleaned" structures remain
   - Address building security & physical hazards
2. **Demolition & Debris Fill (Limited Re-sale/Re-development)**
   - Traditional asbestos & other HBM abatement & disposal off-site
   - Demolition of powerhouse & screenhouse (subgrade walls, slabs, & footings) to 6 feet below ground surface (bgs), except east wall/floodwall: Segregate & salvage
   - Clean debris (masonry, concrete) crushed on-site and used as basement fill; balance of clean fill for capping per approved FPS alteration design
3. **Demolition & Clean Fill (Best Re-sale/Re-development)**
   - Traditional asbestos & other HBM abatement & disposal off-site
   - Demolition of powerhouse structure to top of pilings: Segregate & salvage
   - Off-site disposal of all non-salvaged building materials
   - Would require construction of 400 feet of new floodwall
   - Subgrade walls, slabs, footers demolished & removed
   - Screenhouse structure demolished to water level
4. **Residual Landfill**
   - Limited asbestos abatement and disposal in basement vault
   - Remove other HBMs & dispose off-site
   - Demolition to 6 feet bgs (except east wall/floodwall) : Segregate & salvage
   - Register/permit as residual landfill for on-site asbestos disposal
   - Clean debris (masonry, concrete) crushed and used as basement fill; Balance clean fill per FPS alteration design
   - Considerable regulatory permitting hurdles

Key Potential Issues

- FPS - Floodwall alteration
  - Metropolitan Sewer District (MSD) and US Army Corps of Engineers (USACE) are lead agencies for permitting
  - Alteration must meet current USACE design specifications
  - Sealing of FPS penetrations / conduits are critical elements
  - Ongoing communications of FPS alteration strategies
- Property may not be highly marketable due to FPS
- Regulatory permitting / agency concurrence with strategies
- Address MSD and USACE stakeholder regulatory requirements to facilitate the planned demolition.
- National Environmental Policy Act (NEPA)
- Public relations & communications
- Potential historic value / preservation of structure
- Knowledge gaps (roof, fire brick, fuel tanks, etc.)
- Scrap value offsets some costs – market varies
- Abandonment of intake/discharge structures below Ohio River Level

Risks of Inaction

- Continued deterioration of structure and HBMs
- Increasing safety hazards to employees and trespassers
- Increasing potential for uncontrolled asbestos/other releases
- Negative agency / public reaction to deteriorating conditions
- Cost escalation

Option 1: Mothball

This option involves traditional hazardous building material (HBM) abatement and off-site disposal, with ongoing maintenance of current structure.

Est. Year	General Sequence of Work
1	Planning (budgeting, additional environmental assessment, permitting, stakeholder/public involvement, etc.)
2	Establish safe work environment: Remove/repair/ restrict access to internal unsafe structures (e.g., metal grating); Install covers/rails as needed for floor openings, etc.
	Asbestos abatement and off-site disposal
	Removal and off-site disposal of other HBM (e.g., mercury-containing devices, lead paint chips, PCBs, residues, tanks, etc.)
	Improve site security
3	Stabilize/maintain structures

Benefits
Initiates actions to address issues and risks
Lowers risks for LG&E employees and trespassers
Demonstrates a pro-active approach to address concerns
HBM on-site risks eliminated
Reduces risk of potential negative public / agency reaction
Avoids FPS alteration issues

Risks / Negatives
Structures & components will continue to deteriorate
Does not eliminate risk altogether, including safety risks to LG&E employees and trespassers
Monitoring & maintenance costs will continue and escalate

Key Permits: Asbestos Removal Permits

Option 2: Demolition & Debris Fill

This option involves traditional hazardous building material (HBM) abatement and demolition, with salvageable materials and HBM sent off-site for sale, recycling, or disposal. Clean demolition debris (e.g., densified or crushed concrete and masonry) to be used for basement backfill in powerhouse and screen house. Clean demolition debris is estimated to provide approximately 25-45% of required volume for basement backfill. Based on recent input from the USACE, backfill materials can include clean, densified demolition debris materials, sand, soil, concrete, grout, or other materials so long as hydrologic models confirm the FPS will maintain integrity during the design flood event. May require closure of intake and discharge structures to satisfaction of USACE.

Est. Year	General Sequence of Work
1	Design & permit any alteration(s) of current FPS (408 permit)
	Planning (budgeting, additional environmental assessment, permitting, stakeholder/public involvement, NEPA, etc.)
2	Establish safe work environment: Remove/repair/ restrict access to internal unsafe structures (e.g., metal grating); Install covers/rails for floor openings
	Abatement and off-site disposal of asbestos
	Removal and off-site disposal of other HBM (e.g., mercury-containing devices, lead paint chips, PCBs, residues, tanks, Etc.)
2-3	Demolition of above-grade structure to 6 feet bgs except east wall/floodwall as specified per USACE approved FPS alteration
	FPS alteration

Benefits
Eliminates exposure risks to LG&E employees and trespassers; HBM on-site risks eliminated
Demonstrates a pro-active approach to address concerns
Improves site value and eliminates future escalation costs for abatement
Provides cost recovery for salvage materials and clean infill materials for basement
Reduces risk of potential negative public / agency reaction
Reduces risk of cost escalation
Minimizes on-going maintenance costs

Risks / Negatives
Historical significance could affect scope of demolition or FPS alteration approval by MSD/USACE
MSD / USACE permit requirements for FPS alteration will strongly influence project strategy
Cost to complete and potential for budget overruns

Key Permits: 408 Floodwall Permit; Water Quality Permits; Wrecking Permit; Asbestos Removal Permits

Option 3: Demolition & Clean Fill

This option involves traditional abatement and complete structural demolition with all building materials sent off-site for recycling/ disposal and engineered basement backfill. The primary intent of this option is to better position the property for potential redevelopment and/or resale. This option will require relocating the existing floodwall and may require closure of the intake and discharge structures to the satisfaction of the USACE.

Est. Year	General Sequence of Work
1	Design & permit any alteration(s) of current FPS (408 permit)
	Planning (budgeting, additional environmental assessment, permitting, stakeholder/public involvement, NEPA, etc.)
2	Establish safe work environment: Remove/repair/ restrict access to internal unsafe structures (e.g., metal grating); Install covers/rails for floor openings, etc.
	Abatement and off-site disposal of asbestos
	Removal and off-site disposal of other hazardous building materials (e.g., mercury-containing devices, lead paint chips, PCBs, residues, tanks, etc.)
2-3	FPS alteration, including construction of 400 feet of new floodwall
	Demolition of structures, including basement walls, slabs, and footers, except as specified for FPS alteration
	Recover salvageable material value to maximum extent practicable; off-site disposal of all other building materials
	Basement filled with engineered fill and capped as specified for FPS alteration

Benefits
Eliminates exposure risks for LG&E employees and trespassers
Demonstrates a pro-active approach to address concerns; best option for sale/redevelopment
Removes risks of further building deterioration, structure maintenance, trespassers
Clean, homogenous fill and removal of building foundations allows the widest range of possible reuse options
HBM on-site risks eliminated
Reduces risk of potential negative public / agency reaction
Reduces risk of cost escalation
Eliminates ongoing maintenance costs

Risks / Negatives
MSD / USACE permit requirements for flood wall / levee alteration will strongly influence project strategy
Historical significance could affect scope of demolition
Highest cost option with potential for budget overruns

Key Permits: 408 Floodwall Permit; Water Quality Permits; Wrecking Permit; Asbestos Removal Permits

Option 4: Residual Landfill

This option involves traditional hazardous building material (HBM) abatement and demolition, with salvageable materials and HBM sent off-site for sale, recycling, or disposal, except that asbestos will be disposed in the basement structure and the site permitted as a residual landfill. Clean demolition debris (e.g., densified or crushed concrete and masonry) to be used for basement backfill in powerhouse and screenhouse. Clean debris is estimated to provide approximately 25-45% of required volume for basement backfill. Based on recent input from the USACE, backfill materials can include clean, densified demolition debris materials, sand, soil, concrete, grout,or other materials so long as hydrologic models confirm the FPS will maintain integrity during the design flood event.   This option may require closure of the intake and discharge structures to the satisfaction of the USACE.

Est. Year	General Sequence of Work
1	Design & permit any alteration(s) of current FPS (408 permit) Alteration
	Planning (budgeting, additional environmental assessment, permitting, stakeholder/public involvement, NEPA, etc.)
2	Establish safe work environment: Remove/repair/ restrict access to internal unsafe structures (e.g., metal grating); Install covers/rails for floor openings, etc.
	Abatement of above-grade asbestos and disposal in basement/vault. Limited asbestos removal below-grade.
	Removal and off-site disposal of other hazardous building materials (e.g., mercury-containing devices, lead paint chips, PCBs, residues, tanks, etc.)
2-3	Demolition of structures to 6’ bgs, except east wall/floodwall as specified for FPS alteration
	Recover salvageable material value to maximum extent practicable
	Use clean concrete and masonry for fill on-site as much as practical
	Basement filled with demolition debris & capped as specified for FPS alteration

Benefits
Less expensive than traditional ‘abate & demolish’ options
Initiates actions to address issues and risks
Demonstrates a pro-active approach to address concerns
Lowest cost for abatement.
Reduces risk of potential negative public / agency reaction
Reduces risk of cost escalation

Risks / Negatives
May not be feasible because residual landfill would be immediately adjacent to floodwall
Historical significance could affect scope of demolition
Hazardous materials still on-site
Site will become solid waste facility/landfill, with obligations for long-term stewardship
Regulatory agencies may not approve residual landfill concepts or methods
Limited below-grade activities may limit salvage value
Potential negative public reaction / public meetings

Key Permits: 408 Floodwall /Levee Permit; Water Quality Permits; Residual Landfill Permit; Wrecking Permit; Asbestos Removal Permits

Stakeholders

Potential Stakeholder	Interest	Potential Issues
SHPO, Portland Historic District	Historic Preservation	Resistance to demolition or significant site alteration
KDWM	Waste characterization & disposition	Modify EPA ID No. Registration, waste manifesting, transportation
KDWM	Residual Landfill	Permitting & Design
KDOW / MSD	Work in or along river	Permitting
KDOW / MSD	Storm water quality	Permitting, BMPs
MSD / USACE	Flood Protection System Integrity	Current Design Criteria; 408 Permit; NEPA review
MSD / USACE	Work in Floodplain	Permitting
Louisville Metro APCD	Asbestos abatement methods	Permitting, monitoring
Residents/Neighboring Businesses	Air Quality, Noise, Traffic, Visual, Economic	Public relations, security, safety, air monitoring, communications
KOSHA	Safety	Variances, Inspections
USACE / MSD / PSC	Publicly Funded Project	NEPA Documentation
Louisville Metro Departments (Dept. Inspections, Permits, and Licensing)	Demolition, Street Closures, etc.	Permitting (Wrecking Permits, etc.)
Public and Private Utilities	Utility easements, connections, etc.	Utility relocates, disconnects, etc.
Public Service Commission (PSC)	Financial Planning	Financial Planning

Implementation Phase Planning

- Engineering & Permitting of Flood Protection System Alteration Measures (408 Permit Application)
- Conduct Comprehensive Surveys: ACM, PCBs, chemicals, wastes, building materials, equipment
    - Additional ACM Survey:
        - Roof materials
        - Fire Brick
        - Other difficult to access materials
        - Quantify known ACM to determine abatement specifications and more accurate costs
    - Building material characterization, e.g., for PCBs in concrete, paint, building sealants (e.g., caulk), wiring insulation, lamp ballasts, and other electrical equipment. All structural paints presumed to be lead-containing.
    - Sample & analyze fire brick/mortar for asbestos, hexavalent Cr, NORM (naturally-occurring radioactive material) to determine management during abatement/demolition
    - Chemical inventory: inventory hazardous materials/wastes in drums & other containers (LBP chips, etc.)
    - Universal waste inventory: e.g., lamps, mercury-containing devices, etc
    - Inventory stacks, ducts, pipes that may contain waste residues/ash
    - Quantify steel, copper and other salvageable materials/equipment (detailed material takeoffs)
    - Verify status of tanks. Remove or close in place any remaining USTs.
    - Site investigation to identify and delineate subsurface contamination issues, if deemed necessary

- Interface with regulatory agencies to determine final permitting requirements, NEPA Documentation, and site restrictions for preferred option
    - MSD – Metropolitan Sewer District
    - USACE – US Army Corps of Engineers
    - DOW - Kentucky Division of Water
    - APCD – Louisville Metro Air Pollution Control District
    - SHPO – State Historic Preservation Office
    - KDWM – Kentucky Division of Waste Management

- Obtain permits and prepare NEPA documents as required, prepare compliance plans, etc.
- Preliminary Bid Package – to refine estimates with demolition / abatement contractors
- Develop final estimated project costs for selected option
- Public Input / Meetings

Permitting

Type of Permit	Regulatory Agency	Existing Permits/ Registrations?	New Permit Required?	Potential Option(s) Affected	Timeframe to Prepare/ Obtain
Flood Protection System Permit (408)	MSD / USACE	No	Yes	2, 3, 4	Minor: 90-120 days Major: 12-18 mo
Asbestos Removal Air Permits	APCD	• Asbestos Blanket Permit 350014 expiring 12/31/2013: non-friable • Asbestos Blanket Permit 350015 expiring 12/31/2013: friable	Yes	all	<30 days
Site Disturbance - Erosion/Sediment Control Plan	MSD and KDOW – Surface Water Permits Branch	No	Yes	2, 3, 4	<30 days
401 Water Quality Certification / Permit to Construct Across or Along a Stream	KDOW – Floodplain Management Section	No	Yes	2, 3, 4	<90 days
KPDES Storm Water Discharge Permit with BMP Plan	KDOW – Storm water Permits Branch / MSD	No	No	2, 3, 4	<90 days
Construction in Floodplain	USACE / MSD	No	Yes	2, 3, 4	60 days+
Wrecking Permit	Louisville Metro Dept. of Codes & Regulations, MSD	No	Yes	2, 3, 4	<60 days 30 day waiting period
Residual Landfill	KDWM-Solid Waste Branch	No	Only if option 4 selected	4	180 days+
Hazardous Waste Registration	KDWM – Hazardous Waste Branch	RCRA registration as CESQG / transporter (EPA ID # KYD985092329)	May need to modify for quantity	all	<30 days
DOT Registration	USDOT	TBD	Yes	all	<30 days
Hazardous Material Spill Prevention & Control Plan/Permit (HMPC)	MSD	Lessee HMPC	Yes	all	<30 days
HAZMAT Permit	Louisville Metro Fire Department	TBD	Yes	all	<30 days
NEPA Documentation	USACE / MSD	No	Likely	2, 3, 4	3-12 mos.+

Order-of-Magnitude Cost Estimates

OPTION No.	DESCRIPTION	Planning ($ million)	Demolition ($ Million)	Asbestos & Haz. Building Material Abatement ($ Million)	Steel Salvage Value ($ Million)	Flood Protection System Alteration ($ Million)	Estimated Order-Of-Magnitude Total Cost ($ Million)
1	**Mothball Structures**	0.3	--	2.0	-	N/A	2.3
2	**Demolition & Debris Fill**	0.4	2.0	2.0	(0.3)	0.3	4.4
3	**Demolition & Clean Fill**	0.4	4.0	2.0	(0.3)	1.2	7.3
4	**Residual Landfill**	0.5	2.0	1.5	(0.3)	0.3	4.0

DRAFT

Assumptions / Notes:

1. Option 3 only: Design and construction of new 400 ft Floodwall section to connect floodwalls near NE building corner and NE parking lot corner with Minor Modification 408 permit and closure of intake and outlet structure to outside the floodwall.
2. Roofing will be removed as part of demolition operation. Roofing material is assumed to contain asbestos. Additional sampling is recommended to confirm.
3. Current estimated steel salvage value is included: non-ferrous and copper salvage not included.
4. No structure repair, roof repair, lifecycle or rehabilitation costs are included for Option 1.
5. No costs of demolition of underwater structures, sheet pile, or dewatering are included.
6. Imported backfill material may consist of sand or engineered fill capped by three feet of crushed limestone, but must ultimately comply with FPS alteration design.
7. Concrete/Masonry to be processed to 8" minus and free of rebar if reused on site as backfill.
8. Estimated field duration is 9 to 12 months for abatement & demolition (does not include FPS alteration implementation).
9. Includes Project Management, Health and Safety Monitoring and on-site general project superintendent
10. These cost estimates to be updated as regulatory requirements and LG&E preferences are finalized.

Tank Status Based on Records Review

Per UST Registration Records								Per Other LG&E Records		
Tank No.	**Size (gal)**	**Estimated Age (Yrs)**	**Location**	**Concrete Vault**	**Use**	**Last Contents**	**Date Last Used**	**Date Closed**	**Removed or Filled**	**Comments**
1 (C-4)	1000	87	Not Identified	Y	Heating	Kerosene	Mid 50's	12/10/1991	Removed	No closure sample data
2 (C-4)	500	87	South of Storage Bldg	Y	Heating	Kerosene (Diesel)	Early 70's	12/30/1991	Removed	PAHs < 1 ppm in soil samples
3 (C-5)	1000	77	Not Identified	Y	Heating	Kerosene	Early 70's	2008	Filled	
4 (C-5)	1000	77	Not Identified	Y	Heating	Kerosene	Early 70's	2008	Filled	
5 (B)	500	77	Inside Plant	N		Used Oil	Early 70's			assumed to be above ground tank
6 (B)	500	77	Inside Plant	N		Used Oil	Early 70's			assumed to be above ground tank
7 (B)	1000	77	Inside Plant	N		Used Oil	Early 70's			assumed to be above ground tank
8 (B)	1000	77	Inside Plant	N		Used Oil	Early 70's			assumed to be above ground tank
9 (BR)	1000	77	Inside Plant	N		Empty	Early 70's			assumed to be above ground tank
10 (B)	500	77	Inside Plant	N		Used Oil	Early 70's			assumed to be above ground tank

Notes: PAHs - Polyaromatic Hydrocarbons

Summary Table of Limited Asbestos & Lead-based Paint Sample Results

Material Description	Sample Numbers	Result	Type of Asbestos	Friability
Pyrobar	1A, 1B, 1C, 1D	None Detected	--	F
Plaster	2A, 2B, 2C	None Detected	--	F
Caulk	**3A, 3B, 3C**	**2-3%**	**Chrysotile**	**NF**
Cable Tray	4A, 4B, 4C	None Detected	--	F
Boiler Seam	**5A**	**35%**	**Chrysotile**	**F**
Stack	**6A, 6B, 6C**	**5%**	**Chrysotile**	**F**
Boiler Gasket	**7A**	**35%**	**Chrysotile**	**F**
Exterior Siding	**8A, 8B, 8C**	**30%-40%**	**Chrysotile**	**NF**

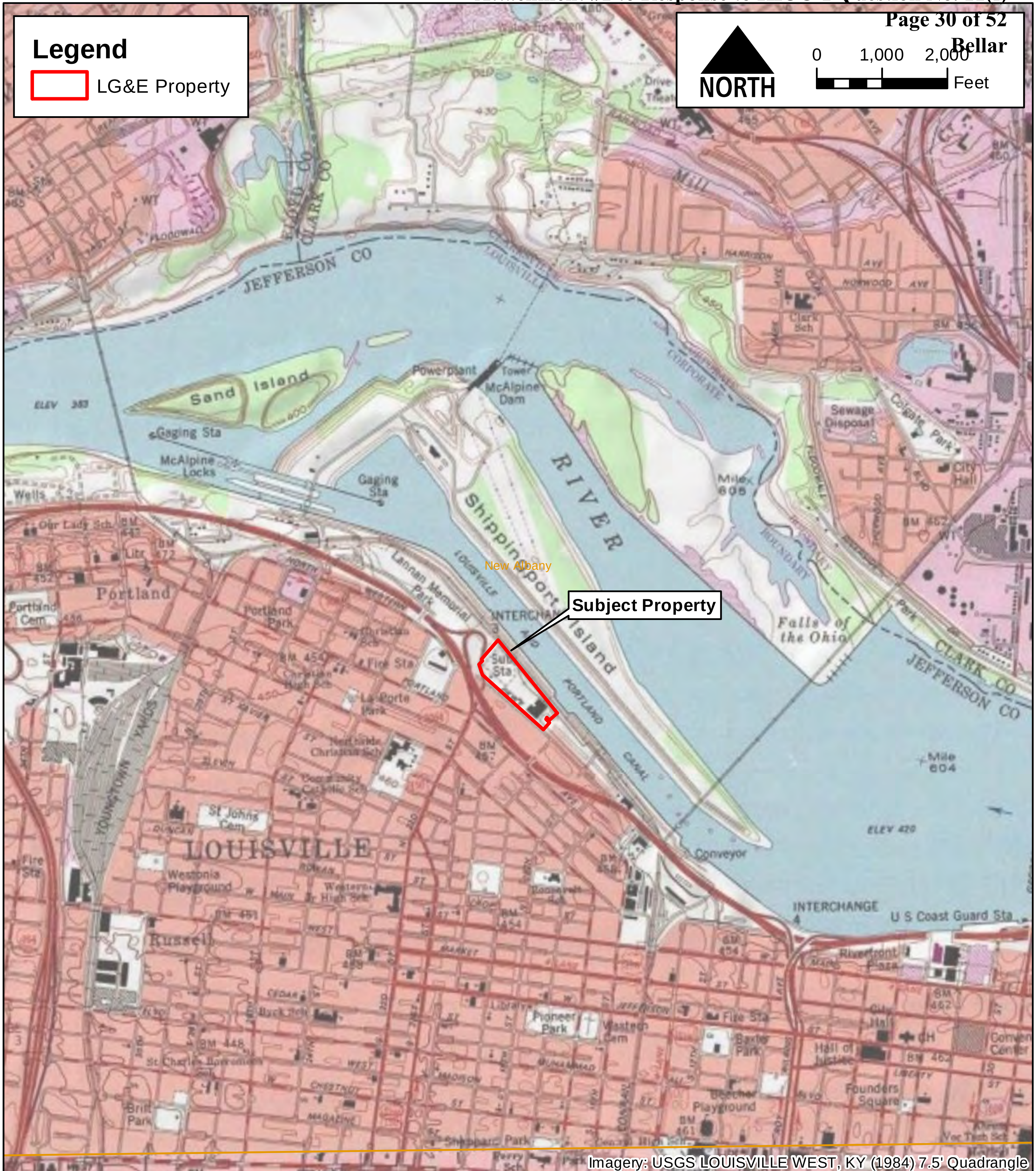
Notes:
F - Friable
NF - Non-Friable

Sample ID	Sample Location	Building	Lead Result % wt	OSHA Level % wt
L1	White Office	Canal Station	0.39	>0%
L2	Pink Office	Canal Station	0.28	>0%
L3	Gray/Orange Boiler	Canal Station	15	>0%

Notes:
Any amount of lead requires compliance with OSHA regulations.
wt - weight

APPENDIX 2

FIGURES

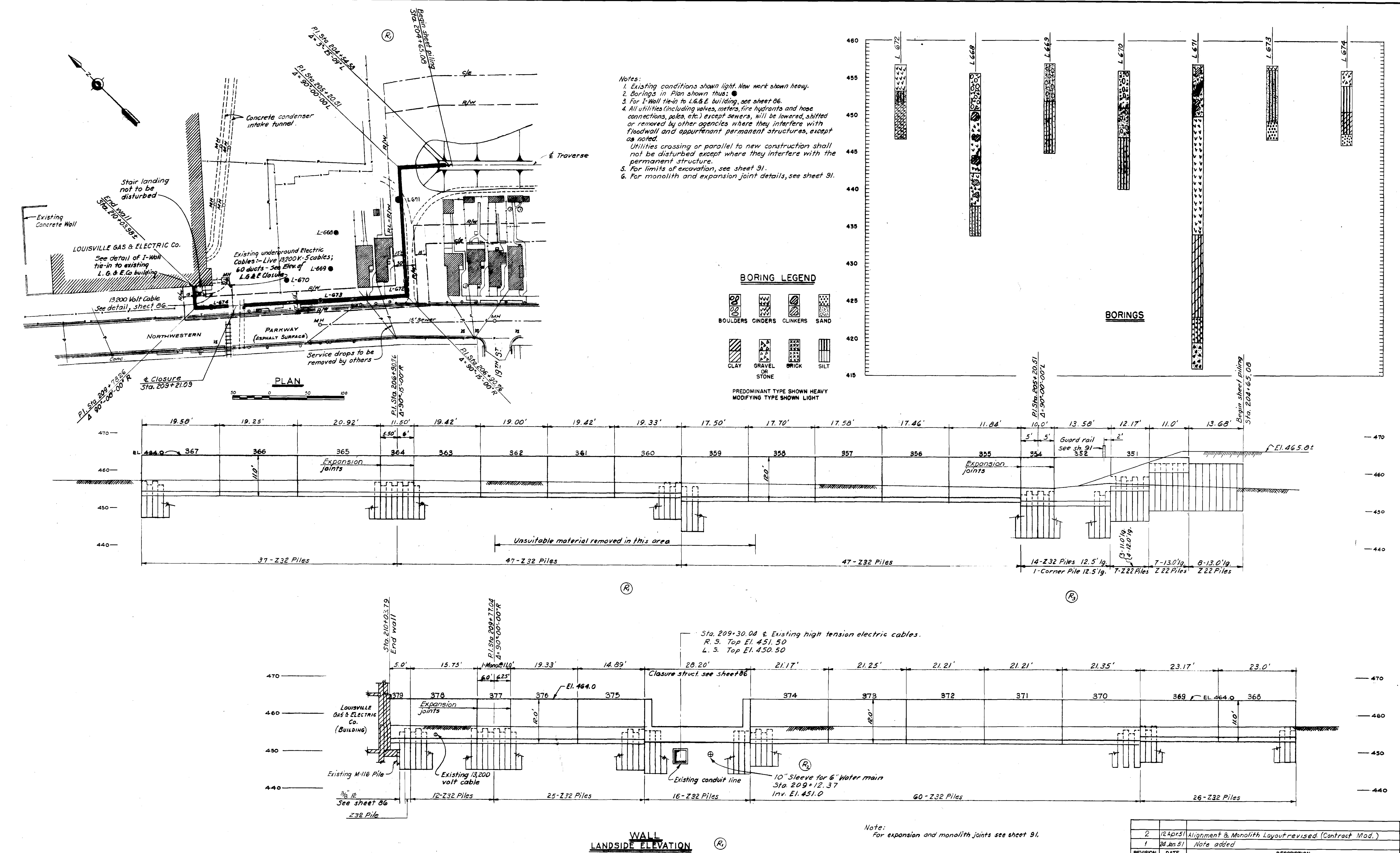


LG&E	Louisville Gas & Electric	MAP BY: SAM	SITE LOCATION MAP	DATE: 05-02-13
AMEC Environment & Infrastructure 690 Commonwealth Center 11003 Bluegrass Parkway Louisville, KY 40299	amec	DATUM: NAD83 PROJECTION: UTM Zone 16N SCALE: 1:24000	CANAL STATION LOUISVILLE GAS & ELECTRIC LOUISVILLE, KY	PROJECT NO: FIGURE NO: 1

amec Environment & Infrastructure, Inc. 11003 Bluegrass Pkwy. Suite 690 Louisville, KY 40299 Tel: (502) 267-0700 Fax: (502) 267-5900	CLIENT: Louisville Gas & Electric 220 West Main Street, Suite 1400 Louisville, KY. 40202	CLIENT LOGO: LG&E	DRAWN BY: CAK CHK'D BY: DATUM: NAD83 PROJECTION: UTM 16N SCALE: AS SHOWN DATE: 06/14/2013	PROJECT: CANAL STATION LOUISVILLE GAS & ELECTRIC LOUISVILLE, KY	Legend Floodgate Floodwall Levee LG&E Property	FIGURE 2A

FIGURE 2B GENERAL LOCATION PLAN

CORPS OF ENGINEERS — U.S. ARMY



Note:
For expansion and monolith joints see sheet 91.

(R3) Piling changed, Monolith No. 353 Deleted
(R2) Water main added, Contract Mod. No. 2
(R1) Stations & dimensions changed

REVISION	DATE	DESCRIPTION	BY
2	12Apr51	Alignment & Monolith Layout revised (Contract Mod.)	S.F.F.
1	24 Jan 51	Note added	W.A.H.

CORPS OF ENGINEERS, U. S. ARMY
OFFICE OF THE DISTRICT ENGINEER
LOUISVILLE, KENTUCKY

OHIO RIVER BASIN
FLOOD PROTECTION LOUISVILLE, KY.
PUMPING PLANTS

I WALL LAYOUT
STA. 204+51.34 TO STA. 210+06.98

DESIGNED BY:
DRAWN BY: L.W.H. – F.S.V.
TRACED BY: F.S.V.
CHECKED BY: W.A.H.
SUBMITTED: CHIEF, ENGINEERING DIVISION
APPROVED: CHIEF ENGINEERING ASSISTANT
APPROVED: LT. COL., CORPS OF ENGINEERS, DISTRICT ENGINEER
DATE: OCT 1950
APPROVED:
DATE:
SCALE: AS SHOWN
DRAWING NUMBER 607-12.5/85

AS BUILT

FIGURE 2C FLOOD WALL ALIGNMENT & DETAILS

WINDOW SCHEDULE

TYPE	WIDTH (W)	HEIGHT (H)	GLASS SIZE
A	6'-3⅛"	7'-8¾"	12"x 18"
B	6'-3⅛"	4'-8"	12" x 18"
C	5'-2¾"	7'-8¾"	12" x 18"
D	5'-2¾"	6'-2⅜"	12" x 18"
E	5'-2¾"	4'-8"	12" x 18"
F	Same as	D - no ventilator	
A.F	Same as A except	as noted below	
G	5'-2¾"	3'-1⅝"	12"x 18"

FIGURE 3A CROSS SECTION-TURBINE ROOM

FIGURE 3B CROSS-SECTION - BOILER ROOM

FIGURE 4A CROSS-SECTION FLOODWALL-BASEMENT WALL

FIGURE 4B CROSS-SECTION 2 - FLOODWALL-BASEMENT WALL

APPENDIX 3

PHOTO LOG

AMEC Environment & Infrastructure, Inc.
Photographic Record

Client: LG&E | **Project Number: 7362131577**

Site Name: Canal Station | **Site Location: 2005 Northwestern Parkway, Louisville, KY**

Photographer:

D. Lane

Date:

3/12/13

Direction:

NNW

Comments:

P-1 – View of Canal Station east side.

Photographer:

D. Lane

Date:

3/12/13

Direction:

NA

Comments:

P-2 – View to basement and intake structures.

AMEC Environment & Infrastructure, Inc.
Photographic Record

Client: LG&E	**Project Number: 7362131577**
Site Name: Canal Station	**Site Location: 2005 Northwestern Parkway, Louisville, KY**

Photographer: D. Lane **Date:** 3/12/13 **Direction:** SW **Comments:** **P-3 –** View of floodwall east side of building.	
Photographer: D. Lane **Date:** 3/12/13 **Direction:** N **Comments:** **P-4 –** Floodwall north of building. .	

AMEC Environment & Infrastructure, Inc.
Photographic Record

Client: LG&E	**Project Number: 7362131577**
Site Name: Canal Station	**Site Location: 2005 Northwestern Parkway, Louisville, KY**

Photographer: D. Lane **Date:** 3/12/13 **Direction:** SE **Comments:** **P-5 –** View of former kerosene/diesel tanks.	
Photographer: D. Lane **Date:** 3/12/13 **Direction:** NE **Comments:** **P-6 –** View of chimney.	

AMEC Environment & Infrastructure, Inc.
Photographic Record

Client: LG&E	**Project Number: 7362131577**
Site Name: Canal Station	**Site Location: 2005 Northwestern Parkway, Louisville, KY**

Photographer: D. Zopff **Date:** 3/12/13 **Direction:** **Comments:** **P-7 –** Boiler room, insulation deterioration.	
Photographer: M. Matilainen **Date:** 3/12/13 **Direction:** NA **Comments:** **P-8 –** Sampling gasket material on boiler. .	

AMEC Environment & Infrastructure, Inc.
Photographic Record

Client: LG&E	**Project Number: 7362131577**
Site Name: Canal Station	**Site Location: 2005 Northwestern Parkway, Louisville, KY**

Photographer: D. Zopff **Date:** 1/11/13 **Direction:** **Comments:** **P-9 –** Deteriorating paint.	
Photographer: D. Zopff **Date:** 3/12/13 **Direction:** NA **Comments:** **P-10 –** Deteriorated insulation and paint in turbine room. .	

AMEC Environment & Infrastructure, Inc.
Photographic Record

Client: LG&E	**Project Number: 7362131577**
Site Name: Canal Station	**Site Location: 2005 Northwestern Parkway, Louisville, KY**

Photographer:

M. Eldridge

Date:

3/12/13

Direction:

Comments:

P-11 – Paint and insulation deterioration.

Photographer:

D. Lane

Date:

3/12/13

Direction:

NW

Comments:

P-12 – Turbines.
.

APPENDIX 4

OPTION 3: DEMOLITION WITH CLEAN FILL

ORDER-OF-MAGNITUDE COST ESTIMATE DETAILS

Cost Estimate Summary (Order-of-Magnitude)
Option 3: Demolition with Clean Fill

OPTION No.	DESCRIPTION	Planning ($ Million)	Demolition ($ Million)	Asbestos & Haz. Building Material Abatement ($ Million)	Steel Salvage Value ($ Million)	Flood Protection System Alteration ($ Million)	Estimated Order-Of-Magnitude Total Cost ($ Million)
3	**Demolition & Clean Fill**	0.4	4.0	2.0	(0.3)	1.2	7.4

Assumptions:

1. Design and construction of new 400 ft Floodwall section to connect floodwalls near NE building corner and NE parking lot corner with Minor Modification 408 permit and closure of intake and outlet structures to outside the floodwall.
2. Roofing will be removed as part of demolition operation. Roofing material is assumed to contain asbestos. Additional sampling is recommended to confirm.
3. Current estimated steel salvage value is included: non-ferrous and copper salvage not included.
4. No costs of demolition of underwater structures, sheet pile, or dewatering are included.
5. Imported backfill material may consist of sand or engineered fill capped by three feet of crushed limestone, but must ultimately comply with FPS alteration design.
6. Estimated field duration is 9 to 12 months for abatement & demolition (does not include FPS alteration implementation).
7. Includes Project Management, Health and Safety Monitoring and on-site general project superintendent

HBM Abatement Cost Estimate (Order of Magnitude)
Option 3: Demolition with Clean Fill

DESCRIPTION	RESULTS	COMMENTS	APPROXIMATE QUANTITY	UNITS	UNIT RATE	BASE PRICE
Ground Contamination	Assumed Positive	From siding, stacks, ducts and pipes	300	SF	$25.00	$7,500.00
Floor Tile	Assumed Positive	Office Area	4,500	SF	$5.00	$22,500.00
Pipe Insulation	Assumed Positive	Throughout	10,000	LF	$25.00	$250,000.00
Above Grade Thermal Insulation	Assumed Positive	Includes all thermal except piping	5,000	SF	$25.00	$125,000.00
Below Grade Thermal Insulation	Assumed Positive	Includes all thermal except piping	5,000	SF	$25.00	$125,000.00
Window Caulk	AMEC Confirmed Positive	Throughout	200	EA	$100.00	$20,000.00
Transite and Metal Siding	AMEC Confirmed Positive	On siding and electrical panels	15,000	SF	$10.00	$150,000.00
Gaskets	AMEC Confirmed Positive	Throughout	3,000	LF	$25.00	$75,000.00
Wire and Cable Insulation	Assumed Positive	Throughout	300	LF	$10.00	$3,000.00
Refractory Brick	Assumed Positive	Inside boilers	3,000	SF	$25.00	$75,000.00
Containerized Materials	Assumed Positive	Includes tanks, lights, drums, switches	250	EA	$500.00	$125,000.00
Lead Paint	AMEC Confirmed Positive	Worker protection requirements	500	SF	$50.00	$25,000.00
Ash	Assumed Positive	Located throughout process equipment	100	CY	$250.00	$25,000.00
C&D Waste	Assumed Positive	Throughout and includes lead paint chip disposal	100	CY	$250.00	$25,000.00
Boiler Roofing	Assumed Positive	Need Samples	13,500	SF	$10.00	$135,000.00
Intake Screen House Roofing	Assumed Positive	Need Samples	450	SF	$10.00	$4,500.00
Stacks	AMEC Confirmed Positive	Stacks Partially Removed	6,000	SF	$25.00	$150,000.00
Plaster and pyrobar	AMEC Confirmed Negative	Throughout offices	0	SF	$25.00	$0.00
Waste Characterization	NA	Hazardous waste characterization	50	EA	$250.00	$12,500.00
Engineering	NA	Testing, Specifications, Monitoring and Oversight	180	EA	$1,500.00	$270,000.00
				SUB TOTAL		$1,625,000.00
				CONTINGENCY	20%	$325,000.00
				TOTAL		$1,950,000.00

Demolition Cost Estimate (Order of Magnitude)
Option 3: Demolition with Clean Fill

Task/Activity/Item	Quantity	Units	Rate	Extension	Notes
Mobilization	1	lump sum	$50,000	$50,000	Includes mob , fencing, site overheads, etc.
Clean Demolition(inc stacks)	65,000	square feet	$5	$325,000	Stacks will be as much as half this number
Process Conc./Masonry	12,000	cubic yards	$30	$360,000	Process for T&D
Load T&D	12,000	cubic yards	$45	$540,000	Assumes non impacted
Process Steel	1,500	tons	$65	$97,500	Shear to acceptable size to smelter
Steel Credit	1,500	tons	-$200	-$300,000	P&S, boilers, does not include copper
Misc. Disposal	1,185	cubic yards	$37	$43,845	Windows, trash, partitions
Basement Work	1	lump sum	$150,000	$150,000	remove to top of piling & just above water intake level, chute to river to remain
Sheet piling	27,610		$35	$966,350	Three sides of turbine room to allow excavation of basement structure.
Backfill	28,000	cubic yards	$12	$336,000	import sand and cap with engineered fill
Oversight, procurement, HSE	8	months	$45,000	$337,500	Assumes 1/3 PM full CM and HSE representation
GC Markup	1	lump sum	10%	$136,235	Assumes AMEC procures and manages
Engineering Support+plans specs	1	lump sum	8%	$108,988	
Contingency	1	lump sum	25%	$459,020	
		With Credit		$ 3,610,437	Does not include copper and assumes $200/Ton
		Without Credit		$ 3,910,437	40% of this cost to separate and demo only boiler house, leaving trolley/turbine room

Implementation Phase Planning Cost Estimate (Order of Magnitude)
Option 3: Demolition with Clean Fill

- Comprehensive ACM surveys & quantification of ACM to develop abatement specifications and more accurate costs: $25,000
- Development of abatement and demolition specifications, detailed salvage material takeoffs, and complete bid packages: $50,000
- Conducting inventories of hazardous materials/wastes, universal wastes, equipment, examine ducts/pipes/tanks/pits to identify residuals: $10,000
- Sampling & analysis of fire brick to determine management during abatement/demolition: $5,000
- Building material characterization, e.g., for PCBs in concrete, paint, caulk: $50,000
- Subsurface environmental due diligence to support property sale: $125,000
- Resolution of historic preservation & viewshed issues: $10,000
- Obtaining required permits; $50,000
- NEPA Documentation: $50,000

Total $ 375,000

APPENDIX 5

OPTION 3: STAKEHOLDERS AND PERMITS

Potential Stakeholders

Potential Stakeholder	Interest	Potential Issues
MSD / USACE	Flood Protection System Integrity	Current Design Criteria; 408 Permit; NEPA review
MSD / USACE	Work in Floodplain	Permitting
KDOW / MSD	Work in or along river	Permitting
KDOW / MSD	Storm water quality	Permitting, BMPs
KDWM	Waste characterization & disposition	Modify EPA ID No. Registration, waste manifesting, transportation
Louisville Metro APCD	Asbestos abatement methods and NESHAPs compliance	Permitting, monitoring
Louisville Metro Departments (Dept. Inspections, Permits, and Licensing)	Demolition, Street Closures, etc.	Permitting (Wrecking Permits, Street Closure, etc.)
Public Service Commission (PSC)	Financial Planning	Financial Planning
USACE / MSD / PSC	Publicly Funded Project	NEPA Documentation
KOSHA	Safety	Variances, Inspections
Neighboring Businesses and Residences	Air Quality, Noise, Traffic, Visual, Economic	Security, safety, air monitoring, communications
SHPO, Portland Historic District	Historic Preservation	Resistance to demolition or significant site alteration
Public and Private Utilities	Utility easements, connections, excavations	Utility relocates, disconnects, capping, etc.
State of Indiana (Counties, Cities)	Viewshed, Air Quality	Viewshed consultation, Air Monitoring

Anticipated Regulatory Permits and Approvals

Type of Permit	Regulatory Agency	Existing Permits/ Registrations?	New Permit Required?	Agency Timeframe to Issue Permit
Flood Protection System Permit (408)	MSD / USACE	No	Yes	Minor: 90-120 days Major: 12-18 mo
Asbestos Removal Air Permits	APCD	• Asbestos Blanket Permit 350014 expiring 12/31/2013: non-friable • Asbestos Blanket Permit 350015 expiring 12/31/2013: friable	Yes	<30 days
Site Disturbance - Erosion/Sediment Control Plan	MSD and KDOW – Surface Water Permits Branch	No	Yes	<30 days
401 Water Quality Certification / Permit to Construct Across or Along a Stream	KDOW – Floodplain Management Section	No	Yes	<90 days
KPDES Storm Water Discharge Permit with BMP Plan	KDOW – Storm water Permits Branch / MSD	No	No	<90 days
Construction in Floodplain	USACE / MSD	No	Yes	60 days+
Wrecking Permit	Louisville Metro Dept. of Codes & Regulations, MSD	No	Yes	<60 days 30 day waiting period
Hazardous Waste Registration	KDWM – Hazardous Waste Branch	RCRA registration as CESQG / transporter (EPA ID # KYD985092329)	May need to modify for quantity	<30 days
DOT Registration	USDOT	TBD	Yes	<30 days
Hazardous Material Spill Prevention & Control Plan/Permit (HMPC)	MSD	Lessee HMPC	Yes	<30 days
HAZMAT Permit	Louisville Metro Fire Department	TBD	Yes	<30 days
NEPA Documentation	USACE / MSD	No	Likely	3-12 mos.+

FINAL DRAFT- BUSINESS CONFIDENTIAL

LOUISVILLE GAS & ELECTRIC
CANE RUN STATION

ESTIMATE OF ABATEMENT, DISMANTLING AND DEMOLITION LIABILITIES

Prepared for:
Louisville Gas & Electric
Louisville, Kentucky

Prepared by:
Amec Foster Wheeler
Environment & Infrastructure, Inc.
Louisville, Kentucky

October 14, 2015

Project 567530029

CONTENTS

TABLES

FIGURES

APPENDICES

LIST OF ACRONYMS

AC	alternating current
ACM	asbestos-containing material
Amec Foster Wheeler	Amec Foster Wheeler Environment & Infrastructure, Inc.
AST	aboveground storage tank
BTU	British Thermal Units
DC	direct current
DCS	*Estimate of Abatement, Dismantling, and Demolition Liabilities*
ESP	electrostatic precipitator
FOB	freight on board
GIS	geographic information systems
GSU	generator step up
LG&E	Louisville Gas & Electric
MGD	million gallons per day
MW	megawatt
NOx	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
OWS	oil/water separator
PCB	polychlorinated biphenyl
RFP	Request for Proposal
RS Means	*RS Means Facilities Construction Cost Data*
SWPPP	Storm Water Pollution Prevention Plan
Work	abatement, dismantling and demolition
USACE	United States Army Corps of Engineers
UST	underground storage tank

EXECUTIVE SUMMARY

Louisville Gas & Electric Company (LG&E) has requested that Amec Foster Wheeler Environment & Infrastructure, Inc. (Amec Foster Wheeler) complete this draft *Estimate of Abatement, Dismantling, and Demolition Liabilities* (DCS) for the Cane Run Coal fired power station in Louisville, Kentucky. The purpose of the DCS was to estimate the value of the Power Station's scrap assets and estimate the cost of decommissioning and demolishing the Power Station, including regulated materials removal and disposal.

The DCS presents the retirement costs for Cane Run Station in three main categories. The first category is asbestos abatement/removal and waste management. The second is plant demolition and the third is scrap asset recovery. Scrap assets include structural steel and equipment, such as boilers, turbines, generators, tanks, wiring and other electrical equipment and processing equipment. Included in the demolition category is the cost to restore the site to Brownfield conditions.

The scope of this estimate includes the following key cost elements:

- Abatement of asbestos-containing materials (ACMs).
- Recovery of plant equipment (boilers, turbines, generators, tanks and processing equipment), specialty metals, structural steel, and miscellaneous steel as scrap.
- A cost credit for the scrap based on current scrap prices.
- Demolition of the building structures and foundations to grade except in the main power building. The east wall will remain in-tact. North, south and west walls will be removed to at least three feet below final grade. Equipment pedestals will be removed to basement floor level.
- Management of waste streams in accordance with applicable environmental regulations and recordkeeping to demonstrate compliance.
- Restoration of the site associated with the bringing the plant properties to a brownfield state, including tank removal or closure, oil-water separator dismantling and removal, and removal/recycling of universal waste.

The estimate has been prepared to meet a Class 3 estimate in accordance with the AACE International Recommended Practice 18R-97: *Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries.* A Class 3 estimate has an expected accuracy range of -20% to +30%. No contingency has currently been added to the numbers in this draft report.

Planned retirement costs, including scrap recovery credits, by category are:

Table 1. Planned Retirement Costs Summary

Feature of Work	Retirement Cost
Regulated Material Abatement	$15,350,497
Demolition	$23,833,850
Restoration	$4,465,791
Scrap Credit	-6,572,142
Total	$37,077,726

Amec Foster Wheeler has made a number of assumptions pertaining to the planned retirement activities. These include:

- This estimate assumes the Power Station has been shut down by LG&E, and the abatement and demolition contractors begin work when the power station equipment is de-energized and isolated.
- Tanks, boilers, precipitators, and coal and ash handling systems, including hoppers, conveyor systems, feeders, collectors, etc. will be decommissioned by LG&E. Some residual CCR and coal dust is expected.
- Utilities will be de-energized by LG&E.
- On-site fuel inventories will be burned or removed by LG&E prior to demolition. Restoration of the coal yard will be performed by LG&E.
- Equipment, structural steel, and metal alloys, where possible, will be credited for scrap.
- Switchyards are to remain operational and are not currently being considered for retirement.
- The screen house will remain. The feedwater piping system and discharge tunnels are to remain intact. The piping and tunnel structures will be plugged at or below ground level where they are cut from the structure. This estimate does not contemplate full grouting of these structures.
- The estimate does not include land valuation considerations.
- This estimate does not include performing additional surveys or environmental studies to further quantify asbestos, polychlorinated biphenyls (PCBs), and regulated materials present at the power station.
- Operation, decommissioning, and post-closure maintenance of ash ponds and disposal units is excluded.
- Security, site lighting including navigation/FAA lighting is not included in this estimate.
- The estimate excludes oversight costs that may be incurred by an Owner's Engineer and LG&E.

The retirement estimates presented in this DCS are based upon information provided during the preparation of the study.

1.0 INTRODUCTION

1.1 Study Objectives

Louisville Gas & Electric (LG&E) has requested that Amec Foster Wheeler Environment & Infrastructure, Inc. (Amec Foster Wheeler) complete this *Estimate of Abatement, Dismantling, and Demolition Liabilities* (DCS) for the Cane Run Coal-Fired Power Station in Louisville, Kentucky. The purpose of the DCS was to estimate the value of the Power Station's scrap assets and estimate the cost of decommissioning and demolishing the plants, including asbestos removal and disposal and environmental obligations.

The DCS presents the retirement costs for Cane Run units 1-6 and associated equipment in three main categories. The first category is regulated material removal and waste management. The second is plant demolition and the third is scrap asset recovery. Scrap assets include structural steel and equipment, such as boilers, turbines, generators, tanks, processing equipment, wiring, condiuits and other equipment. Included are restoration costs to bring the site to a brownfields condition.

1.2 Plant Descriptions

1.2.1 Cane Run Power Station

The Cane Run Power Station is adjacent to the Ohio River. The site is 10 miles southwest of Downtown Louisville, Kentucky at, 5252 Cane Run Road, Louisville, Kentucky, in its Pleasure Ridge Park neighborhood. The coal fired powered station has six units. Units 1, 2 and 3 were first commissioned in 1954.

The facility includes ancillary structures engineered to support the six separate steam turbines in the main powerhouse building. Structures including the main powerhouse building and other structures on the property support the six power units which have a collective rated output of approximately 800 megawatts (MW). Thirty-six different structures/equipment exist outside the main power building, which include but are not limited to the Lime Storage Tanks, Reactant Supply Building, Warehouses 17 and 19, Maintenance Warehouse, Coal Yard Equipment Shed, Shaker House, Conveyors, Crusher House, Drive House, and Engine House, North Fly Ash Bin, Slurry Barge Unloading Structure, Water Trailers, and transformers. A detailed description of each building and the asbestos-containing material (ACM) identified within each building is located within Amec Foster Wheeler's August, 2015 Limited NESHAPs survey. The coal-fired generation facility was in operation from 1954 to 2015.

The Power Station handling system controls emissions through the use of electrostatic precipitators. Stacks 1 through 5 are approximately 250 feet high. The stack for unit 6 is approximately 500 feet high. The coal fired operation has recently been replaced by a 650 MW combined cycle gas turbine system which was commissioned in the summer of 2015. This is Kentucky's first natural gas combined cycle generating unit.

Control equipment for the ash handling system includes two sludge processing plants which combine ash and lime to produce a stabilized positec product which is then stored on site.

During operation the plant drew water from the Ohio River through a single screen house located on the bank of the river, to the west of the main power house. The new combined cycle gas unit (Cane Run Unit 7) also utilizes this screen house for feedwater and some of the existing discharge tunnel system to release water back to the Ohio River.

There is one external outfall that discharges cooling water, processed waste water, treated bottom ash pond water and an unspecified amount of storm water from the plant at Outfall 001.

Amec Foster Wheeler reviewed a Kentucky Pollutant Discharge Elimination System (KPDES) permit provided by Louisville Gas & Electric (LG&E). A summary of the permit is presented as folloows:

<u>Permit No.: KY0002062, AI No.: 2121</u> - The permit authorizes LG&E to discharge from the Cane Run Generation Station to the Ohio River and Mill Creek Runoff. The permit became effective on May 1, 2015 and expires on April 30, 2020. Outfalls authorized by this permit are based on tiers of plant operations. Each outfall is identified by number and type, and includes latitude/longitude, receiving water and outfall description. The monitoring locations are summarized by tier as follows:

- Tier 1 is described as the existing coal-fired Units 4, 5, and 6, and the natural gas combined cycle (NGCC) Unit 7 Power Station. When the coal-fired units are taken out of operation, Tier 2 monitoring locations will replace Tier 1 monitoring locations. Tier 1 direct outfall to the Ohio River includes condenser cooling water, non-contact cooling water, stormwater from roof drains. Internal outfall includes fly ash sluice water, fly ash economizer/air heater sluice water, bottom ash sluice waters, pyrites/mill reject sluice waters, sanitary wastewater plant effluent, boiler chemical waste water, plant wastewater, cooling tower blowdown, low volume waste water, stockpile runoff and coal combustion residuals (CCR) landfill runoff. Intake outfall includes water from plant intake.
- Tier 2 is described as operations of the NGCC Unit 7 plant, reclamation of the CCR landfill, coal stockpile and ash pond. When the CCR landfill, coal stockpile and ash pond reclamation is complete and approved by the Kentucky Division of Water and all coal related activities have ceased, Tier 3 monitoring locations will replace Tier 2 monitoring locations. Tier 2 direct outfall to the Ohio River includes effluent from Units 4, 5, and 6, NGCC Unit 7 cooling tower blowdown and stormwater roof drains, Internal outfall includes CCR landfill and coal stockpile runoff, low volume waste waters, NGCC Unit 7 plant waste waters, sanitary plant effluent, and stormwater. Intake outfall will include plant intake water.
- Tier 3 is described as operations of the NCCC Unit 7 plant. Direct outfall to the Ohio River will include effluent from NGCC Unit 7 plant and Unit 11 wastewaters, and NGCC Unit 7 plant cooling tower. Internal outfall includes NGCC Unit 7 and Unit 11 wastewaters, low volume wastewaters from retired coal-fired unit sumps, sanitary wastewater plant effluent. Intake discharge includes plant intake.

The permit included limitations and monitoring requirements, by tier for each individual outfall. The permit stated requirements for Standard Effluent, WET testing and testing methods, sampling, serial dilution, controls and reporting requirements. Special Conditions stipulated in the permit include Division of Water mixing zones for one or more pollutants, Best Management Practices, Compliance, products prohibited from release, requirements for installation of NOx reduction devices. A Clean Water Act Exclusion for reporting and liability for Ammonium Hydroxide, Sodium Hypochlorite, Ethylene Diaminetetracetic Acid (EDTA), Sodium Hydroxide, Sodium Nitrite, Sodium Phosphate (Dibasic), and Sulfuric Acid discharges. LG&E will be required to place permanent markers for all outfalls discharging to the Ohio River, and it was recommended to place permanent markers at all other outfalls and monitoring locations. All laboratory analysis and tests shall be conducted by an EEC certified general wastewater laboratory. Also included was a letter from the Kentucky Division of Water, dated April 30, 2015 regarding LG&E comments to a previous draft of the permit. The comments and responses appeared to be related to clarifications and/or omissions presented in the draft permit.

1.3 Scope of Estimate

The scope of this estimate includes, but is not limited to, the following cost elements:

- Abatement of asbestos-containing materials (ACMs).
- Recovery of equipment (boilers, turbines, generators, tanks and processing equipment), specialty metals, structural steel, and miscellaneous steel as scrap.
- A cost credit for the scrap.
- Demolition of the building structures and foundations to grade except in the main power building. The east wall of the main power building will remain in-tact. North, south and west walls will be removed to at least three below final grade. Equipment pedestals will be removed to basement floor level.
- Management of waste streams in accordance with applicable environmental regulations and recordkeeping to demonstrate compliance.
- Restoration of the site associated with the bringing the plant properties to a brownfield state, including tank removal, oil-water separator dismantling and removal, and removal/recycling of universal waste.

2.0 APPROACH

2.1 Review of Existing Information

Amec Foster Wheeler requested the following for the Power Station to assist in the DCS:

- Plant drawings.
- Previous surveys and environmental reports

Amec Foster Wheeler reviewed available drawings provided for the Power Station including architectural and structural plans, mechanical, insulation, elevations, and details. LG&E staff at each plant searched the plant's drawing files during the site visit to find the most relevant drawings. Amec Foster Wheeler used these drawings and extensive field visits to estimate quantities for demolition, asbestos containing material and scrap quantities. This take off information was consolidated in order to facilitate internal estimate development and pricing interviews with multiple demolition/environmental contractors.

Following the file review, a team of demolition specialists visited the Power Station to gather the information necessary to develop retirement costs. Amec Foster Wheeler assumed that the plant shut down activities will be performed by LG&E personnel and these costs were not included in the estimate.

2.2 Review of Current Market Cost Data-Contractor Interviews

Amec Foster Wheeler conducted interviews of major demolition and environmental remediation contractors to validate its internal estimate and discuss recent projects, approaches and lessons learned. The current market value for scrap metal is low, as little as a third of what the value was just a year ago. Amec Foster Wheeler determined that pricing derived from projects performed during high scrap value periods would be biased due to the high amount of hidden profits/credits from scrap proceeds. Using the project derived estimated quantities, Amec Foster Wheeler conducted generic project discussions to arrive at multiple contractor derived cost estimates. Amec Foster Wheeler developed and reviewed these different cost scenarios and normalized those costs with limited definition and/or higher degree of risk/variability. These prices were used to validate Amec Foster Wheeler's internal estimate.

2.3 General Approach Assumptions

2.3.1 Contracting Strategy

A formal contracting strategy has been proposed, which includes two separate requests for proposal (RFPs). The first RFP will be for abatement, dismantling, and demolition of structures outside the main power building structure. The second RFP will be issued for abatement, dismantling, and demolition specific to the main power building structure and the 6 stacks associated with Cane Run units 1-6. The pre-qualification process has been initiated and potential contractors have been selected. Awards will be timed such that a contractor will assume control of the site after LG&E completes decommissioning activities, procurement/funding resources are programmed and available and other business factors considered by LG&E.

It is assumed that the contractor's activities will be overseen by LG&E with support from a qualified engineering consultant selected by LG&E. However, costs for LG&E oversight and support from an Owner's Engineer has not been included in the cost estimate.

2.3.2 Estimate Accuracy

The estimate has been prepared to meet a Class 3 estimate in accordance with the AACE International Recommended Practice 18R-97: *Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries.* A Class 3 estimate has an expected accuracy range of -20% to +30% and is the appropriate classification used for project designs at the conceptual stage and for budget authorization/funding. No contingency has been added to the cost estimates shown in this draft DCS Report.

2.3.3 Assumptions

Amec Foster Wheeler has made a number of assumptions pertaining to the planned retirement activities. These include:

- This estimate assumes the Power Station has been shut down by LG&E, and the abatement and demolition contractors begin work when the Power Station is "cold and dark."
- Tanks, boilers, precipitators, and coal and ash handling systems, including hoppers, conveyor systems, feeders, collectors, etc. will be decommissioned by LG&E.
- Utilities will be de-energized by LG&E.
- On-site fuel inventories will be burned or removed by LG&E prior to demolition. Restoration of the coal yard will be performed by LG&E.
- Radiological sources and mercury switches are being removed by LG&E.
- The screen house will remain. The feedwater piping system and discharge tunnels are to remain intact. The piping and tunnel structures will be plugged at or below ground level where they are cut from the Power Station structure. This estimate does not contemplate full grouting of these structures.
- Equipment, structural steel, and metal alloys, where possible, will be credited for scrap.
- Switchyards are to remain operational, are not currently being considered for retirement and require protection through any decommissioning/demolition phases.

- The estimate does not include land valuation considerations.
- This estimate does not include performing additional surveys or environmental studies to further quantify asbestos, polychlorinated biphenyls (PCBs), and regulated materials present.
- Operation, decommissioning, and post-closure maintenance of ash ponds and disposal units is excluded.
- Ongoing KPDES compliance requirements and the associated costs are not part of this estimate.
- This estimate includes no contingency/placeholder for subsurface soil/groundwater investigation or remediation.
- The estimate excludes oversight costs that may be incurred by an Owner's Engineer and LG&E.

Additional assumptions that apply to the individual cost categories are listed in Section 3.

2.3.4 Market Conditions-Scrap Metal

Large demolition of steel structures involves the removal and recycling of structural steel, tankage, electrical equipment and other miscellaneous equipment. Structural and plate steel make are the most predominant (by weight) commodity generated by power station demolition projects. Other metals/alloys include, copper, stainless steel, cupernickel, nickel, etc. Structural and plate steel prices are the most important driver to maximizing returns from scrap proceeds. This market has fallen dramatically over the last year due to dramatic reductions in global demand for scrap steel.

A graph of steel scrap prices over the period from January 2014-2015 is provided as Figure 1.

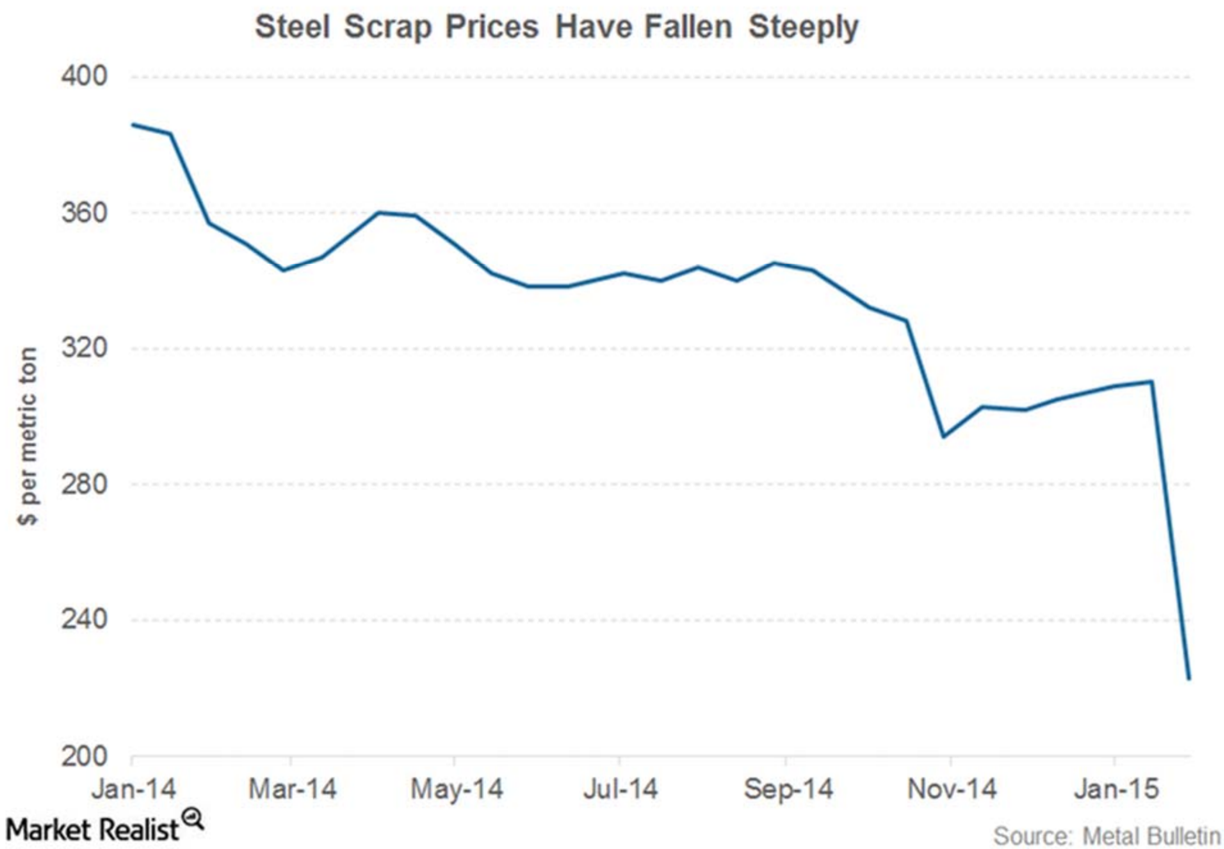


Figure 1. Steel Scrap Prices over the Period from January 2014-2015

A combined mass of 41,000 tons of scrap is estimated currently present on site. A variation of $100/Ton equates to over $4M in potential credit to the project.

The projected scrap market trends should be taken into account when planning procurement for demolition projects so that owners can be prepared for the expected fluctuations in scrap credits to the project. Market periodicals project an improvement to the scrap prices in 2016 Q2. Multiple contractors have told Amec Foster Wheeler that many large projects are on hold due to the current low scrap commodity pricing.

For assets that are planned to be mothballed for any period of time security should be of prime concern. Theft and unauthorized building entrants create a potential reduction in scrap assets but also pose a safety liability. Deterrents to entry should be maintained such as lighting, secure locks and window board-up/enclosure as needed. Maintaining the building envelope will also mitigate deterioration of the structure and the condition of regulated materials.

2.3.5 Seasonal Timing of Procurements

In normal years demolition bidding cycles track fairly closely with construction although demolition is less weather dependent. Through our interviews and other observations made in the market there are large projects on hold due to the low scrap values. Owners planning on large demolition procurements would be advised to have projects ready to solicit prior to Spring in a typical year-when contractors are busy reviewing other projects. This winter would be a good time to solicit bids for the first phase of work at Cane Run. If other factors allow it LG&E may want to delay the main power station demolition until the market for scrap improves. It is advised, however, to proceed with performing surveys and developing packages so that LG&E has the option to solicit bids when the market does improve.

3.0 COST ESTIMATE

3.1 Abatement and Waste Management

3.1.1 Basis of Estimate

Amec Foster Wheeler requested and available historical asbestos survey information for the Power Station. No previous environmental reports related to asbestos or other regulated materials were available. Historical drawings were provided of the Power Station and Amec Foster Wheeler used these to develop preliminary estimated quantity information to support a detailed analysis of likely demolition and environmental abatement costs.

Site visits were conducted to expand takeoff information and fill data gaps in order to develop the final estimated quantity spreadsheets. Once the takeoff information was developed Amec Foster Wheeler performed internal estimates in parallel with contractor interviews to develop and validate the regulated material abatement cost estimate.

3.1.2 Methodology

Site visits were performed in August and September 2015 to gain knowledge of the Power Station's construction. Amec Foster Wheeler was not authorized to perform a regulated building material survey of the main power building as part of this effort. Therefore, suspect materials are assumed to be asbestos containing throughout the main power plant. Amec Foster Wheeler utilized data from the survey that it developed during the summer of 2015 for the structures outside the main power building. Amec Foster Wheeler also relied upon the previously obtained site plans obtained from LG&E, field measurements and knowledge of overall power plant construction.

Amec Foster Wheeler developed a conceptual work approach to identify where large containments would be erected in the Power Station and the size of these containments. By establishing the major containments, Amec Foster Wheeler could then evaluate the quantities of asbestos containing materials provided that were within each work area. After large areas of containment were known, published production rates for asbestos removal (modified to incorporate professional judgment) were used to compile the estimates. Production rates and crew sizes were estimated using a combination of the 2015 *RS Means Facilities Construction Cost Data* (RS Means), and Amec Foster Wheeler's historical knowledge of abatement and deconstruction type demolition work. Amec Foster Wheeler developed labor rates using Building Trades Council Data labor rates for the Power station.

Pricing for major pieces of equipment considered key to performing asbestos abatement, such as four-wheeled forklifts, aerial man lifts, and a crane were obtained by using historical information. The cost of small tools and equipment to be used daily by the working crews was calculated using a standard per day cost. Scaffolding cost estimates for removal of asbestos coatings from the stack at CR 6 were obtained from a nationwide scaffolding contractor that Amec Foster Wheeler has past experience with on other projects. Waste disposal costs were developed based on assigning a relative unit weight to each asbestos abatement item. These weights were derived from commercially available average architectural weights, but with an added factor given for the water that is used during asbestos abatement.

Amec Foster Wheeler compiled the abatement cost estimates in **Appendix A**. Contractor derived costs ranged from $11.8M to $18.5M. The Amec Foster Wheeler estimated abatement cost is $15.1M. Cost breakdowns and take offs are provided in **Appendix A**.

The distribution of abatement costs derived along with the Amec Foster Wheeler estimate (Value No. 1) without contingency, escalation or oversight are shown in the following Figure 2.

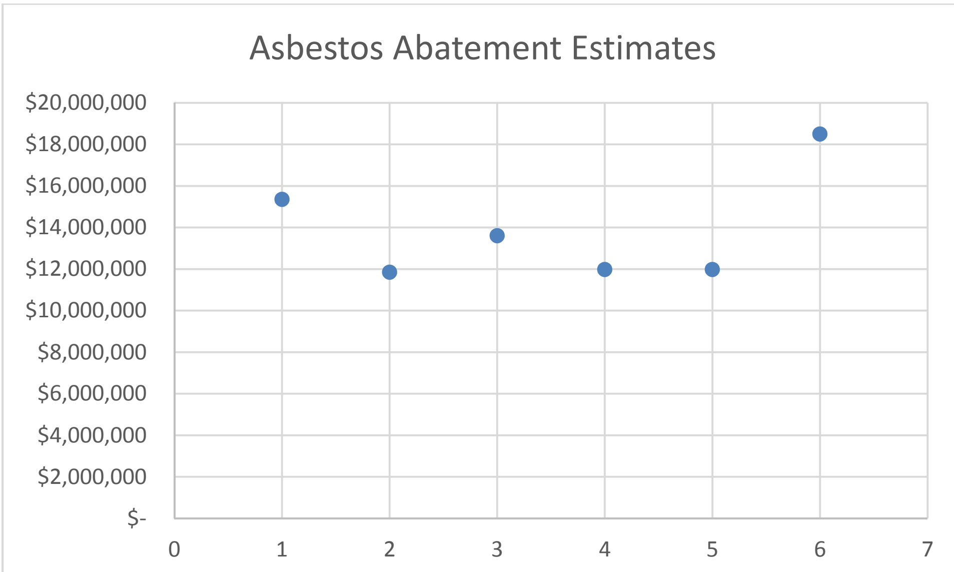


Figure 2. Asbestos Abatement Estimates

3.1.3 Assumptions

1. Amec Foster Wheeler's Asbestos survey data was used to estimate abatement for structures outside the Power Station building. All suspect materials inside the plant were assumed to contain asbestos.
2. The daily rate used to calculate man days is based on eight hours per day, 40 hours per week.
3. Labor rates are based on 2015, no escalation included for actual schedules for abatement. Labor affiliation is assumed to be union.
4. ACM roofing or roofing tar was assumed at the Power Station, either exposed or under "newer" roofing.

3.2 Asset Recovery and Demolition

3.2.1 Methodology

Amec Foster Wheeler worked with the onsite staff to acquire the applicable drawings and documentation for ethe Power Station. Amec Foster Wheeler then performed detailed structural steel and metal flooring take-offs from the available drawings for select areas/structures. Amec Foster Wheeler's August/September 2015 tours of the facility were then used to attempt to mitigate the data gaps; however, in some cases Amec Foster Wheeler had to rely on historical data from similar facilities to fill-in the data gaps. Each boiler unit was evaluated individually based on the specific equipment observed during the site visit. Amec Foster Wheeler then estimated weights based on historical data and extrapolated as necessary to provide a reasonable approximation of weight of scrap material. Scrap price is based on market value as of September 2015 and assumes a blended rate to include ferrous (steel) and nonferrous (copper, etc.) materials.

The asset recovery estimates include both equipment and structural steel. The estimates are based on the structures currently on the sites and observations made in September 2015. The level of estimating presented herein assumes all equipment will be scrapped. Some of the equipment may have salvage value above the scrap value and the opportunities for sale of this equipment can be explored as the decommissioning process progresses. Amec Foster Wheeler based the demolition cost estimates on the obtained drawings and observations during the site visit and validated its estimate against contractor's experience with power plants of similar or of scalable size. These estimates take into account the location of the facilities, the footprint, and height of the buildings, height of the stacks, the skeletal structure, and the equipment support substructure. The asset valuation assumed all equipment is scrap and valuation for steel, copper, brass and other precious metals are tabulated and summarized.

Demolition takeoffs included assembling the cubic footage, square footage, metal mass, concrete/masonry mass estimates. Each structure was reviewed and compared to historical data, e.g. RS Means, Internal Amec Foster Wheeler and contractor cost histories.

3.2.2 Basis of Estimate

Available plans were inventoried and catalogued. Available structural steel plans were evaluated to develop estimates of parts of the plant which were then extrapolated over the entire structure.

The demolition/restoration cost estimates and scrap credit estimates are shown in Appendix B. The estimated demolition costs total ranged from $10M to over $31M. Amec Foster Wheeler's internal estimate is $23,833,580.

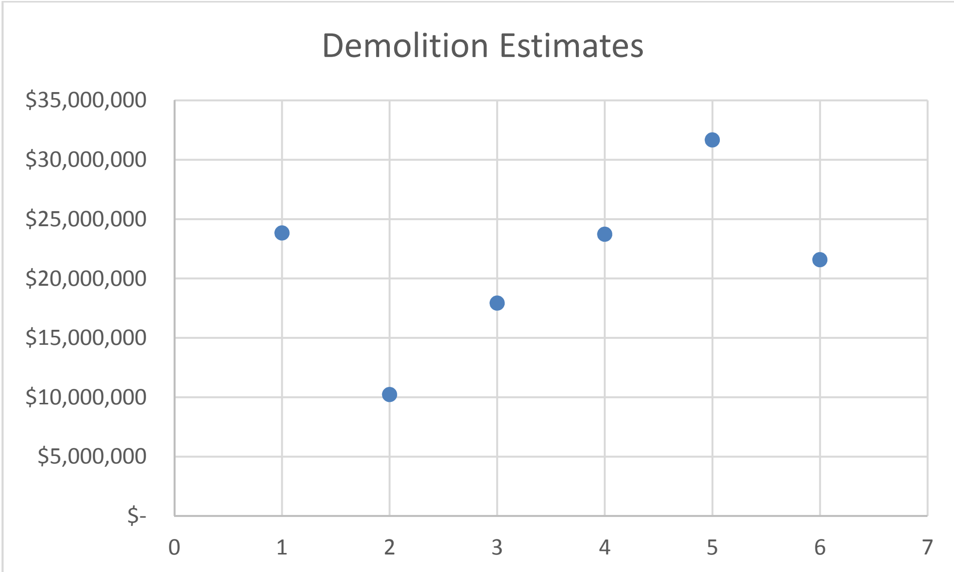


Figure 3. Demolition Estimates

The scrap credits estimated by contractors ranged from $4.5M to $12M. Amec Foster Wheeler's internal estimate for scrap credit based on current market value is $6,572,142. Cost breakdowns and take offs are provided in **Appendix B**.

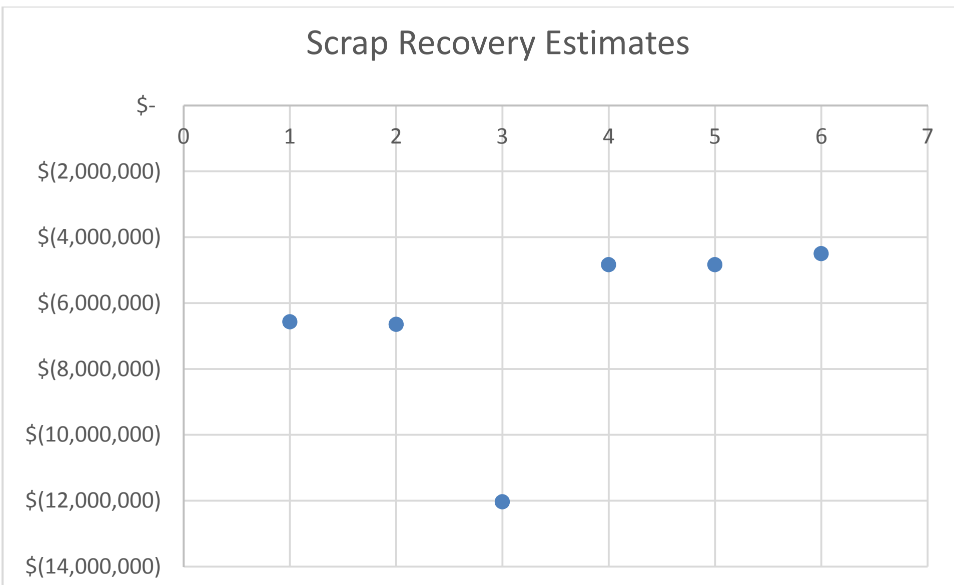


Figure 4. Scrap Recovery Estimate

3.2.3 Assumptions

1. Amec Foster Wheeler's estimated quantities of the steel were derived using On-Screen quantity estimation and some field measurements based on drawings provided by LG&E. Structural steel columns and beams, metal flooring, stairs and landings, and metal handrails were used to estimate final structural tonnage amounts.
2. Boiler and other equipment mass estimates were acquired by comparison to scalable similar projects with known equipment scrap mass.
3. The estimated price used for scrap purposes reflects the "current day" value of steel and other precious metal as per Market Realist September 2015. It should be noted that prices are subject to significant changes.
4. Scrap valuation was based on detailed historical data, as LG&E did not provide cut sheets for the equipment to establish material composition, weights and other pertinent criteria.
5. Necessary permits will be secured prior to the start of the demolition and reclamation site activities.
6. Fire brick within boilers and stacks/chimneys could not be fully accessed for characterization/quantification; therefore quantities were estimated.
7. Final grading to be at approximate current elevation with positive drainage and vegetation establishment.

   Demolition materials excluding structural steel, salvage and clean concrete are to be transported and disposed off-site.
8. Third party utility disconnects including power, natural gas, and water will be completed by the utility provider or LG&E.
9. Exterior perimeter fencing will remain in place during demolition and reclamation activities and will be removed following completion of all site activities.
10. Demolition of the building structures and foundations to grade except in the main power building. The east wall of the main power building will remain in-tact. North, south and west walls will be removed to at least three feet below final grade. Equipment pedestals will be removed to basement floor level.

3.3 Environmental Restoration

3.3.1 Basis of Estimate

The environmental component of the DCS was compiled by experienced professionals familiar with demolition, civil and near Levee restoration projects. Through discussion with LG&E it was determined that the areas outside the main Power Station structure would be removed to ground level with concrete slabs to be left in place. A Levee transects the main power structure from the North and through the Southwest quadrant of the station footprint.

The east basement wall is to remain as well as the basement floor and subsurface footings. Amec Foster Wheeler utilized industry knowledge of typical restoration concerns associated with coal-fired power plants to complete the estimate.

3.3.2 Methodology

Amec Foster Wheeler reviewed the Power Station property with respect to drainage, underground storage tanks, other underground water conveyance systems and the surrounding topography. The demolition quantities were reviewed for potential fill materials that could be used in the basement of the main power structure. It was determined that there would be approximately 25,000 cubic yards of clean fill available assuming proper segregation, processing and no environmental impacts such as from PCBs.

Amec Foster Wheeler developed a conceptual cross section and plan view to illustrate its restoration assumptions. This scenario assumes tying in to the existing Levee at the north and southwest corner of the main power structure.

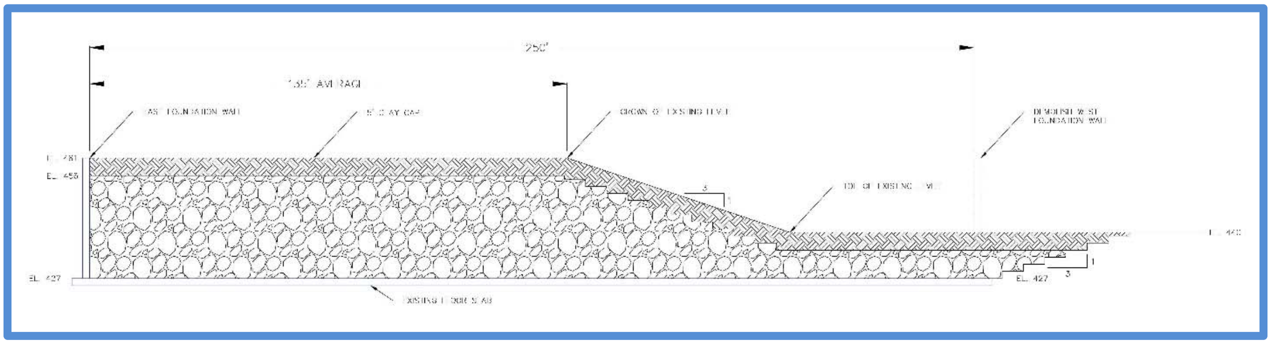


Figure 5. Cross Section of Proposed Main Station Building Restoration

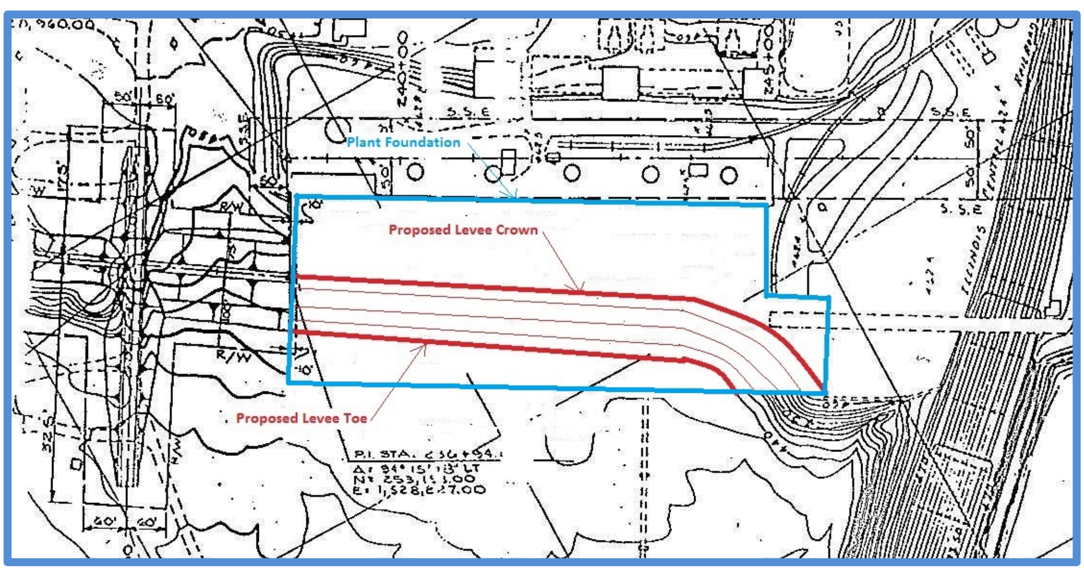


Figure 6. Plan View of Proposed Main Station Building Restoration

Estimated environmental restoration ranged from $2.6M to $4.7M. Amec Foster Wheeler's estimate is $4,465,471.

Assumptions

1. Building materials (such as window glazing, caulking, concrete, steel, equipment and paint) have not been tested for PCB content. No placeholder has been included in the estimate.
2. High voltage cabling was mostly energized at the time of the survey. Tanks, oil-water separators, electrical equipment, and pits/vaults/trenches will be drained by LG&E. However some residual material is expected to remain.
3. Universal waste will be removed by LG&E.
4. Radioactive source equipment is being removed by LG&E.
5. Naturally Occurring Radioactive Material (NORM) has not been surveyed. Firebrick from the boiler structures is assumed to be free of NORM.
6. The costs presented are to bring the plants to a brownfield state. Our estimate does not include remediation of significant releases to soil and groundwater.
7. USTs are assumed to be removed or closed in place.
8. The estimate does not include remediation or reporting costs to achieve closure of soil and groundwater impacts.
9. Contingency, escalation and project oversight costs have not been added to the draft estimate.

4.0 REFERENCES

Amec Foster Wheeler (2015, August 19). *Limited NESHAPs Asbestos & Other Regulated Materials Survey*

RS Means, 2015, *RS Means Facilities Construction Cost Data*

Market Realist Webpage (2015 September)

Scrap Monster Webpage (2015, January), www.scrapmonster.com

APPENDIX A

Abatement Cost Estimate Takeoffs and Support Documentation

APPENDIX B

Asset Recovery/Demolition/Restoration Cost Estimate Takeoffs and Support Documentation

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 12

Responding Witness: Valerie L. Scott

Q.1-12. Please describe the Company's accounting for the demolition costs at Paddy's Run and other retired plants, including the FERC balance sheet and/or expense accounts used to record the costs as incurred, and the expense accounts used to record the depreciation or amortization of the costs, if any. If the Company proposes to depreciate or amortize the costs, then provide the depreciation or amortization period and the rationale for the proposed period.

A.1-12. LG&E's accounting for the costs incurred to demolish the retired plants will be in accordance with the guidelines prescribed in the Code of Federal Regulations 18 CFR, Chapter 1, Subchapter C, Part 101, Electric Plant Instruction 10. LG&E will charge Account 108 - Accumulated provision for depreciation of electric utility plant for the costs to physically retire the plants, e.g. cost of removal and salvage. The costs to demolish the plants will be credited to the steam functional classification in accordance to the Code of Federal Regulations 18 CFR, Chapter 1, Subchapter C, Part 101, Account 108. The Company plans to recover these costs through depreciation rates via a terminal salvage component.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 13

Responding Witness: Christopher M. Garrett

Q.1-13. Please provide a quantification of the revenue requirement for the demolition of the retired plants in the test year, including all rate base/capitalization components and all operating expenses. The quantification should include all reductions in rate base/capitalization and operating expenses from savings, if any.

A.1-13. The Company has not developed or quantified a revenue requirement for the specific projected demolitions and to do so would require original work. The 13 month average balance for expenditures recorded to accumulated depreciation for plant demolitions through the test year is $36.6 million of which $11.7 million was included in the prior rate case.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 14

Responding Witness: John P. Malloy

Q.1-14. Refer to page 17, lines 1-16, of Mr. Malloy's Direct Testimony wherein he describes the deployment-related capital and O&M costs for implementation of the AMS meter deployment as well as the projected savings. The Kentucky jurisdictional O&M expenses for LG&E Electric were estimated on line 7 to be $13.0 million.

a. Please provide the estimated deployment-related O&M expense by FERC account number included in the (a) base year, (b) test year, and (c) 12 months immediately succeeding the test year.

b. Please provide the estimated O&M expense savings by FERC account number, such as meter reading expense, that serve to offset the deployment-related O&M expenses included in the (a) base year, (b) test year, and (c) 12 months immediately succeeding the test year.

A.1-14.

a. O&M Expenses	**Base Year**	**Test Year**	**12-mos Succeeding**
586: Meter Expense	$ -	$ 1,167,421	$ 787,522
597: Maintenance of Meters	-	1,427,900	2,087,644
903: Customer Records and Collection Exp	-	358,833	556,351
910: Miscellaneous Customer Service Exp	-	73,121	84,014
	$ -	**$ 3,027,275**	**$ 3,515,530**

b. O&M Savings	**Base Year**	**Test Year**	**12-mos Succeeding**
586: Meter Expense	$ -	$ -	$ (1,016,000)
902: Meter Reading Expenses	-	-	(896,840)
	$ -	**$ -**	**$ (1,912,840)**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 15

Responding Witness: John P. Malloy

Q.1-15. Refer to page 18, lines 3-16 of Mr. Malloy's Direct Testimony wherein he describes the DNV-KEMA report. Please provide a copy of this report and all cost/benefit analyses, including all quantifications and electronic spreadsheets with formulas intact.

A.1-15. The DNV KEMA report was provided in Case No. 2014-00003 as Exhibit DEH-1. Please see page 1158-1326 of the PDF at this link.

http://psc.ky.gov/pscecf/2014-00003/rick.lovekamp%40lge-ku.com/01172014092917/LGE_KU_DSM_EE_App_1-17-14.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 16

Responding Witness: Robert M. Conroy / John P. Malloy / Counsel

Q.1-16. Refer to page 23, lines 8-14 of Mr. Malloy's Direct Testimony wherein he states:

> The other large driver of savings results from customers using less energy and using it more efficiently as they learn more about their own usage from the web portal that will be available to them as part of the AMS deployment. The Companies and other utilities have observed that customers who actively access such information tend to decrease their usage slightly. Aggregating those savings through 2039 produces net savings of over $166 million (nominal) and over $66 million NPV, which are savings customers will receive directly by reducing their bills through reduced usage.

a. Please confirm that a reduction in customer revenues is not a reduction in the Companies' costs and that the $166 million is not a savings to the Companies. If the Company cannot confirm this, then please explain why not.

b. Please confirm that the reduction in customer revenues does not result in a reduction in the Companies' revenue requirements; it simply means that the Companies' costs must be recovered over fewer billing units, all else equal. If the Company cannot confirm this, then please explain why not.

c. Please provide a copy of all internal correspondence that addresses whether a reduction in revenues is a valid benefit that should be included in the Companies' cost/benefit analyses.

d. Please identify each person, their position, and their role in the decision to include a reduction in revenues as a savings in the Companies' cost/benefit analyses.

e. Please confirm that the Companies recover the revenues lost due to energy efficiency and demand response initiatives through increased charges per billing unit, all else equal. If the Company cannot confirm this, then please explain why not.

A.1-16.

a. The $166 million (nominal) is a savings residential customers are projected to receive directly by reducing their bills through reduced energy usage. The Companies will presumably spend less on fuel and other consumables resulting from these energy savings, though those reduced variable costs will be less than $166 million (nominal). The net reduction in revenues would result in less revenue (at least relatively less revenue) from those customers to meet the Companies' revenue requirements.

b. See the response to a. above.

c. See the Company's objection filed on January 20, 2017. The Company has not identified any non-privileged documents.

d. Decisions such as these are made collectively through a process of information gathering, conversation, and discussion amongst leadership teams across the organization, including senior levels for strategic direction. Final decisions are reviewed in a formal Investment Committee process.

e. Within the terms of the Company's Demand-Side Management ("DSM") Cost Recovery Mechanism (Sheet Nos. 86 *et seq.*), the premise of the question is correct: the mechanism includes a lost sales component (for no more than the three most recent years' lost sales) related to sales lost due to the Company's own DSM and energy efficiency programs (but not to customer-implemented savings measures or practices). Also, the mechanism is billed on a per-kWh basis to customers to whom DSM programs are available.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

**Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.**

Dated January 11, 2017

Question No. 17

Responding Witness: Robert M. Conroy / John P. Malloy

Q.1-17. Refer to Exhibit JPM-1 at Section 7.

a. Refer to page 35 and the references to the 2008 EPRI study. Please provide a copy of this study and all other documents reviewed by the Companies to determine the avoidable non-technical line losses.

b. Please provide the annual actual distribution line losses for the most recent ten years.

c. Please provide a copy of all empirical studies and/or analyses performed by or on behalf of the Companies or other PPL affiliates that attempts to quantify actual non-technical line losses, if any. If none, then please explain why the Companies or other PPL affiliates have not performed such studies and/or analyses.

d. Please provide all studies performed by PPL affiliates that address their actual experience in reduction of non-technical line losses or actual line losses after implementation of AMS.

e. Please confirm that the Companies assume that the AMS meters will have service lives of 20 years and that, once installed, none of the meters will be retired or replaced.

f. Please confirm that the Companies' cost/benefit study is limited to 20 years and does not address replacement of the entirety of the AMS meters within the next 5 years.

g. Please indicate whether the Companies considered a longer cost/benefit study period but decided to truncate the study period in order to avoid including the cost to replace most or all of the AMS meters within the 25 year period.

h. Please provide the average service life for the AMS meters. Provide a copy of all support relied on for this determination.

i. Please confirm that the meters in account 370.20 Meters – AMS at December 31, 2015 were placed in service in 2015.

j. Please confirm that Mr. Malloy agrees with the claims by Mr. Spanos in his depreciation study filed in this proceeding that "These meters are expected to have a shorter average life and maximum life than the standard meters they are replacing. The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential of 25 years." On this basis, Mr. Spanos used 15 years for the service life in his depreciation study. If Mr. Malloy does not agree with Mr. Spanos with respect to the 15 year service life of these meters, then please describe the specific disagreement(s) and the reasons why Mr. Malloy disagrees with Mr. Spanos.

k. Please indicate if Mr. Malloy and Mr. Spanos discussed the assumptions and inconsistencies regarding AMS meter service lives reflected in the depreciation study and/or the AMS business case economic analyses.

A.1-17.

a. See attached. EPRI has recently moved the study referenced by the Company to the public domain. In addition to the EPRI study, the Company referenced Duke Energy Kentucky Inc.'s KPSC Case No. 2016-00152 which cited the same EPRI study.

b. See response to AG 1-13.

c. See attached.

d. The Company is not aware of any studies performed by PPL affiliates that address their actual experience in reduction of non-technical losses or actual line losses after implementation of AMS.

e. The Company confirms that the AMS meters are expected to have service lives of 20 years, but the Company does not confirm that once installed none of the meters will be retired or replaced.

f. The Companies' cost-benefit study is limited to 24 years to include the projected deployment years through the full expected service life of the meters. The cost-benefit study does not address replacement of the entirety of the AMS meters within the next 5 years, which is appropriate because the cost-benefit study also does not attempt to account for the benefits associated with such replacement meters over their useful lifetimes.

g. The Companies considered various cost-benefit study periods but decided to use a 20 year horizon to best align with the expected service life of the meters. See also the response to f. above.

h. The average service life for the AMS meters is assumed to be 20 years. See attached.

i. Confirmed.

j. The Company agrees with the claims by Mr. Spanos.

k. Messrs. Malloy and Spanos did not have such a discussion. But the Company disagrees with the premise of the question. Mr. Spanos noted that lives for AMS-type meters can extend to 25 years. The Companies have their own experience in this regard, particularly with the Landis + Gyr system deployed in Wilmore, Kentucky, which indicates such meters can have service lives beyond 15 years. Therefore, assuming a 20-year useful life for the Companies' cost-benefit analysis was reasonable.

Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

1016049

Advanced Metering Infrastructure Technology

Limiting Non-Technical Distribution Losses In The Future

Technical Update, December 2008

EPRI Project Manager
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Electric Power Research Institute (EPRI)

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This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Advanced Metering Infrastructure Technology: Limiting Non-Technical Distribution Losses In the Future. EPRI, Palo Alto, CA: 2008. 1016049.

PRODUCT DESCRIPTION

Revenue security is a major concern for utilities. Theft of electric service in the United States is widespread. In 2006, the revenue estimate for non-technical losses was $6.5 billion. Non-technical losses are associated with unidentified and uncollected revenue from pilferage, tampering with meters, defective meters, and errors in meter reading. In this report, revenue security describes the use of advanced metering infrastructure (AMI) technology to minimize non-technical losses.

Results and Findings

The report defines revenue security as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. The report distinguishes between revenue losses caused by technical and non-technical factors, with a primary focus on the latter. Integrated with meter data management system (MDMS) technology—software that accepts, stores, and forwards AMI-collected data to utility systems such as billing—AMI significantly improves a utility's ability to monitor customers' electric meters and detect both intentional electricity bypasses and unintentional errors (for example, billing and customer service problems encountered by traditional manual meter-reading operations). The report describes AMI technologies in detail, from enabling hardware and software to transitioning from traditional systems to installation and implementation. The transition from meter reader to meter revenue protection agent also is discussed. A case study concludes the report by describing how PPL Electric Utilities of Pennsylvania successfully deployed and implemented AMR/AMI throughout its entire service territory (1,353,024 meters as of 2006).

Challenges and Objective(s)

Revenue security involves securing revenue that is due distribution utilities from delivery of electricity to end-users. It includes both reducing losses and collecting revenue associated with the electricity delivered. Non-technical distribution losses occur at the point of delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is delivered, measured, and billed. This is the challenge to revenue security.

Applications, Values, and Use

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. After AMI installation, utilities may uncover a substantial number of previously unknown sources of diversion. By reading meters frequently, AMI also identifies bad meters more quickly and reduces the need for estimating unmetered energy use. AMI's improved meter-reading accuracy also results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.

EPRI Perspective

AMI systems provide new and innovative tools for revenue assurance. With comprehensive AMI/MDMS and vigorous meter revenue protection programs, AMI will have a positive impact on minimizing non-technical losses due to theft. In areas other than theft, AMI offers additional advantages, such as using MDMS features in customer service to respond more quickly and accurately to high-bill inquiries.

Approach

The project team gathered information for this report from a variety of sources, including government surveys, industry reports, Internet searches, utilities, and vendors. When determining the impact of non-technical losses on revenue, the team examined aggregate measurements of revenue and distribution losses from reliable government statistical sources and applied ratios from various industry surveys and reports.

Keywords

Advanced metering infrastructure
Revenue assurance
Meter data management systems
Non-technical losses
Meter tampering
Electricity theft

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1
CHAPTER 1

Revenue Security

Revenue security may be viewed as securing revenue that is due to the distribution utilities from the delivery of electricity to end-users. It includes both the reduction of losses and the collection of the revenue that are associated with the electricity delivered. The activities related to revenue security are oftentimes called "revenue protection" or, more recently, "revenue assurance."[1]

Utility revenue is a function of electricity delivered to end-users (kWh) and the billing rate ($/kWh).

This is expressed in the following formula:

$$R = E_d * r$$

Where:

R = Revenue ($)
E_d = Energy delivered (kWh)
r = rate ($/kWh)

The electricity delivered to end-users is generation minus losses in generation, transmission, and distribution. Distribution losses are divided into two components, technical and non-technical.

This is expressed in the following formula:

$$G - (L_g + L_t + L_{d+} L_n) = E_d$$

Where:

G = Gross generation
L_g = Generation losses
L_t = Technical losses – transmission
L_d = Technical losses – distribution
L_n = Non-technical losses
E_d = Energy delivered

Transmission losses and technical distribution losses relate to the physical characteristics and functioning of the electrical system itself. Non-technical distribution losses occur at the point of

[1] Revenue assurance includes theft detection and follow-up, metering malfunctions, billing errors and the like, consumption on inactive accounts, and collections. These activities will be discussed at length in Chapter 2.

delivery and measurement. Minimizing non-technical losses increases the amount of electricity that is *delivered*, *measured, and billed*. This is the challenge to revenue security.

Distribution Losses

Losses in power distribution systems have two components: technical and non-technical.

Technical Losses

Technical loss is the component of distribution system losses that is inherent in the electrical equipment, devices, and conductors used in the physical delivery of electric energy.

Technical loss is intrinsic to electrical systems, as all electrical devices have some resistance and the flow of currents will cause a power loss (I2R loss). Integration of this power loss over time, i.e. _ I2R.dt, is the energy loss. Every element in a power system (a line or a transformer) offers resistance to power flow and, thus, consumes some energy. The cumulative energy consumed by all these elements is classified as "technical loss." Technical losses are due to energy dissipated in the conductors and equipment used for transmission, transformation, sub-transmission, and power distribution. These occur at many places in a distribution system—for example, in lines, mid-span joints and terminations transformers, and service cables and connections.

Technical losses vary greatly in terms of network configuration, generator locations and outputs, and customer locations and demands. In particular, losses during heavy loading periods or on heavily loaded lines are often much higher than those that occur in average or light loading conditions. This is because a quadratic relationship between losses and line flows can be assumed for most devices of power delivery systems. It is not possible to altogether eliminate such losses, which are inherent in a system; they can, however, be reduced to some extent.

Technical losses include the load and no-load (or fixed) losses in the following:

- Sub-transmission lines
- Substation power transformers
- Primary distribution lines
- Voltage regulators
- Capacitors
- Reactors
- Distribution transformers
- Secondary distribution lines
- Service drops
- All other electrical equipment necessary for distribution system operations

Technical losses also include the electric energy dissipated by the electrical burdens of the metering equipment such as potential and current coils and instrument transformers.

Technical losses can be calculated based on the natural properties of components in the power system: resistance, reactance, capacitance, voltage, current, and power.

Non-Technical Losses

Non-technical loss is the component of distribution system losses that is not related to the physical characteristics and functions of the electrical system. Rather, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These are conditions that the technical losses computation fails to take into account. Such losses are caused primarily by human error, whether intentional or not. Non-technical losses are associated with unidentified and uncollected revenue arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of the utilities due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses.

Non-technical losses also can be viewed as undetected load—customers that utilities do not know exist. When an undetected load is attached to the system, the actual losses increase while the losses expected by the utilities will remain the same. The increased losses will show on the utility's accounts, and the costs will be passed along to the customers as transmission and distribution charges.

Reasons for non-technical (or commercial) losses:

- Non-performing and under-performing meters
- Incorrect application of multiplying factors
- Defects in current transformer (CT) and potential transformer (PT) circuitry
- Non-reading of meters
- Pilferage by manipulating or bypassing of meters
- Theft by direct tapping and so on

All these losses are due to non-metering or under-metering of actual consumption. Non-technical losses occur at many places in a distribution system. These are shown in the following insert.[2]

[2] *Best Practices in Distribution Loss Reduction*, DRUM Program, Power Systems Training Institute, Bangalore – 560070. December 2007. The DRUM (Distribution Reform, Upgrades and Management) project is a series of training and capacity building programs in distribution. The broad objective of the training program is to share relevant regional and international experience in the management of distribution business. The program will cover all the important aspects of the distribution business ranging from regulatory matters such as approaches to tariff setting, open access, and reforms to issues of concern to utilities such as quality of service, information management, and energy efficiency. It is supported by USAID and the Ministry of Power, India.

Losses Due to Non-Technical Reasons	
Loss at consumer end meters	Poor accuracy of meters
	Large errors in CTs/PTs
	Voltage drop in PT cables
	Loose connections in PT wire terminations
	Overburdened CT
Tampering/bypass of meters	Where meters without tamper-proof/temper-deterrent/tamper-evident meters are used
	Poor quality sealing of meters
	Lack of seal issue, seal monitoring and management system
	Shabby installation of meters and metering systems
	Exposed CTs/PTs where such devices are not properly securitized
Pilferage of energy	From overhead "bare" conductors
	From open junction boxes (in cabled systems)
	Exposed connections/joints in service cables
	Bypassing the neutral wires in meters
Energy accounting system	Lack of proper instrumentation (metering) in feeders and detector tubes (DTs) for carrying out energy audits
	Not using meters with appropriate data logging features in feeder and DT meters
	Lack of a system for carrying out regular (monthly) energy accounting to monitor losses
	Errors in sending end meters, CTs and PTs
	Loose connections in PT wires (which result in low voltage at feeder meter terminals)
	Energy accounting errors (by not following a scientific method for energy audits)
Errors in meter reading	Avoiding meter reading due to several causes such as house locked and meter not traceable
	Manual (unintentional errors) in meter reading
	Intentional errors in meter reading (collusion by meter readers)
	Coffee shop reading
	Data punching errors (at MRI and by meter readers)
	Data punching errors by data entry operators
	Lack of validation checks
	Lack of management summaries and exception reports on meter reading
Errors in bills	Errors in raising the correct bill
	Manipulation/changes made in meter reading at billing centers—lack of a system to assure integrity in data
	Lack of a system to ensure bills are delivered
Receipt of payment	Lack of a system to trace defaulters, including regular defaulters
	Lack of a system for timely disconnection
	Care to be taken for reliable disconnection of supply (where to disconnect)

Factors Contributing to Non-Technical Losses

Theft and Non-payment

The most prominent forms of non-technical loss are electricity theft and non-payment. Electricity theft is defined as a deliberate attempt by a person to reduce or eliminate the amount of money he or she will owe the utility for electric energy. This could range from creating false consumption information used in billings by tampering with the customer's meter to making unauthorized connections to the power grid.

Power theft by existing customers is the predominant cause of loss of revenue to the electrical utilities. Almost all customer classes are involved in this: residential, commercial, industrial, and public entities. The consequences of power theft are manifest in many areas of an electric distribution company's business, including transformer failures, equipment breakdowns, poor revenue collection, financial losses, lower credit rating for the utility, increased technical losses, and the corroded integrity of employees.

Theft of power is committed by bypassing the meter or meter tampering. Totally bypassing the meter is done by directly tapping into the distribution line; partial or full load is then fed directly.

There are numerous methods of meter tampering. New methods are constantly evolving and detection of tampering is a continuous challenge for distribution utilities.

Theft can be active or passive. A customer may actively engage in illegal tampering to avoid the registration on the meter, or a customer may take possession of a property, find that electricity and gas supplies are on, and therefore not apply for service, thus avoiding payment without tampering.

Direct tapping of power by non-customers is another source of theft that is widely prevalent in developing countries. This is mainly in domestic and agricultural categories. Geographical remoteness, mass basis for theft, poor law enforcement capability, and inaction on the part of utilities are helping this phenomenon.

Unmetered Connections

In some countries, certain customers are not metered and energy usage is estimated, instead of measured, with an energy meter. Usually, the loads involved are small and meter installation is economically impractical. Examples of this are street lights and cable television amplifiers. Unmetered connections pose problems in correctly estimating consumption, resulting in losses.

Defective Metering

Losses due to metering inaccuracies are defined as the difference between the amount of energy actually delivered through the meters and the amount registered by the meters.

Tampered, slow-running, stalled, or damaged meters cause substantial losses to distribution utilities. Electromechanical meters tend to get sluggish over a period of time, thus under-recording consumption. Stopped or damaged meters can be in place for many years, resulting in on-going losses.

Virtually all energy meters are subject to these kinds of errors and inaccuracies. Standards and protocols for accuracy audits, repairs, and replacement are required to ameliorate this situation.

Meter-Reading Errors

Meter-reading personnel occasionally make errors in recording their readings. For a good number of services the meter reader, at times, reports nil consumption without any comment. Sometimes the meter reader furnishes no readings or in some cases, furnishes table readings. Another error is the adoption of wrong multiplier factors.

Estimated Bills

Sometimes customer bills are prepared using estimates of consumption. The method of estimating customer consumption can distort recorded losses.

Late Billing and Poor Revenue Collection

Consumer complaints in the billing process can result from incorrect billing due to deficiencies in metering and data processing. Prolonged disputes, lack of consumer-friendly policies, connivance, incorrect identification of category, fictitious billing (of non-existent consumers), lack of reconciliation, and continuous provisional billing are causes for poor revenue collections and, thus, contribute to non-technical losses.

AMI WITH METER DATA MANAGEMENT (MDMS) CAN MITIGATE MANY OF THE FACTORS CONTRIBUTING TO NON-TECHNICAL LOSSES. THE ENABLING TECHNOLOGIES ARE DISCUSSED IN CHAPTERS 2 AND 3.

Non-Technical Loss Contribution to Technical Loss

It is often overlooked that non-technical losses can be a contributing factor to technical loss because of improper load management. Improper load management can lead to overloading of conductors and transformers in the system causing higher losses.

It can be argued that the distortion of load quantities caused by non-technical losses distorts computations for technical losses caused by existing loads, thereby rendering results ineffectual.[3] Energy diversion is a major aggravating factor in this situation.

Reducing non-technical losses may positively impact technical losses by mitigating congestion during periods of peak load when technical losses are particularly high.[4]

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[3] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[4] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Measurement

Non-technical losses, by definition, are losses that are not accounted for and are, therefore, not subject to analytical measurement. Non-technical losses are simply the difference between the energy delivered to the distribution system and billed to end-users, less technical losses. Although there is agreement on the importance of non-technical losses, there is no firm data to define the level of losses on an industrywide basis. However, the importance of non-technical losses, especially in terms of their impact on revenue, is such that distribution utilities try to quantify them.

Such quantification is very difficult. Quantifying what statisticians call "unaccountable for" attempts the impossible. There is an inherent difficulty is obtaining data on unmetered supplies and theft. Estimating the revenue impact of non-technical losses presents yet further difficulties. This is brought into relief when trying to measure the benefits of AMI in reducing non-technical losses. Although there are expectations that AMI will help to reduce non-technical losses, the measurement of benefits (or costs) from AMI deployment are considered non-quantifiable. For example, the framework for the business case adopted by the California Public Utilities Commission lists the reduction of non-technical losses as a benefit, but states that they are "not quantifiable, qualitative."[5]

Utilities rely on studies that are designed to calculate the magnitude, composition, and distribution of system losses based on annual aggregate metering information for energy purchases, energy sales, and system modeling methods. These studies are compared to industry and academic studies and models to establish the magnitude, composition, and distribution of losses.

Utilities have developed methods to measure non-technical losses primarily based on detection by manual meter readings and statistical analysis. These are often inaccurate. This is because the data rely heavily on the records of detected cases, rather than by actual measurement of the electrical power system. The reason that measurement or monitoring the power system is not the preferred method of measuring non-technical losses is because the infrastructure of the system, specifically the metering system, makes accurate and detailed loss determination impossible.[6] Measuring distribution line loses directly is not economic.[7]

The metering system is focused on the end-user, not on intermediary stages in the power distribution where technical and non-technical losses could be more accurately measured.

[5] *AMI Potential Benefits Categories Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure* (Draft Report), Moises Chavez, CPUC and Mike Messenger, CEC April 14, 2004. Easier identification of energy theft is categorized as "not quantifiable, qualitative"; meter accuracy, detection of meter failures, reduction in "idle usage," and billing accuracy are categorized as "short term."

[6] *Non-Technical Losses in Electrical Power Systems*, Thesis, Fritz J. and Dolores H. Russ College of Engineering and Technology Ohio University, Dan Suriyamongkol. November 2002.

[7] For the accurate measurement of technical losses on transmission and distribution systems, it would be necessary to install metering equipment at each voltage level of transmission and transformation.

The only real solution for identifying the non-technical loss component from transmission and distribution losses is through studies at the distribution utility level. Technical losses can be isolated at substations, and the differences with end-use consumption calculated from that point. Unfortunately, such studies are not conducted on a consistent or industrywide basis.

To get a magnitude measure of the impact of non-technical losses on revenue for purposes of this study, the approach is to examine aggregate measurements of revenue and "distribution" losses from reliable government statistical sources and apply ratios from various industry surveys and reports. The available data sources and their limitations must be taken into close account when considering the accuracy of the results. Economic loss levels tend to be system-specific. In the end, the resulting measure of revenue impact from non-technical losses is an order of magnitude estimation. Nonetheless, this approach is sufficient to demonstrate the value of each distribution utility taking its own measure of non-technical losses.

Data Sources

Data on revenue losses from non-technical losses are extremely difficult to come by. Data on non-technical losses are not collected by the Energy Information Administration (EIA) or industry associations. Data on the revenue attributable to those losses are not collected or estimated on an industrywide basis. Electric utilities consider these data confidential because they have implications for operating and financial performance.

Statistics on net generation and "transmission and distribution losses and unaccounted for," measured in kilowatt hours, are available in the Annual Energy Review.[8] Statistics on revenue from retail sales to ultimate customers and the supply and disposition of electricity are available from the Electric Power Annual.[9]

The most exhaustive study on revenue *metering* losses per se was made by EPRI in 2000.[10] The focus of this study was metering, anomalies, metering integrity, and theft rather than revenue and the full economic impact of non-technical losses.[11] This study was conducted before the benefits of automatic meter reading (AMR)/AMI had become noticeable. The study looks forward to that day though in its conclusion.

> "[Utilities have] a strong interest in quantifying these losses to assess their full effect on utility revenues and to provide a basis for mitigating technologies, such as Automatic

[8] Table 8.1 Electricity Overview, 1949-2006, Report No. DOE/EIA-0384(2006), Annual Energy Review 2006.

[9] Table 7.3 Revenue from Retail Sales of Electricity to Ultimate Customers by Sector, by Provider, 1995 through 2006 and Table ES2 Supply and Disposition of Electricity, 1995 through 2006, Electric Power Annual. October 22, 2007.

[10] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

[11] Ibid. For example, the definition of meter/billing errors states, "Included in this class are all scenarios involving personnel actions, where 'people errors' compromise metering integrity because of inexperience, inattention, lack of review, and lack of training. … Meter mis-installation falls into this category."

Meter Reading (AMR), and the development of other future programs to reduce non-technical losses."[12]

The Office of Gas and Electricity Markets in the United Kingdom has conducted a number of studies evaluating the cost of distribution losses, including non-technical losses and also illegal abstractions (tampering with meters and illegal connections).[13]

Statistics

Aggregate statistics for transmission and distribution losses are presented in Table 1-1, along with revenue for the corresponding year. From this data the relationships and trends can be observed that offer insights into transmission and distribution losses, technical and non-technical, at a global level. As stated previously in the section on data sources, unfortunately these are the only statistical series that are available that offer an objective and consistent measure of the relevant variables at any level, from generation to end-user.

Table 1-1
Statistics

Key Statistics							
Year	**Net Generation + Imports (million kWh)**	**T&D+UFE Losses (million kWh)**	**Ratio**	**Revenue from Retail Sales ($ million)**	**Revenue Loss T&D+UFE**	**Revenue Loss per million kWh**	**Rev Loss 2.0%**
1996	3,487,684	230,617	6.6%	212,609	14,058	0.0610	4252
1997	3,535,204	224,380	6.3%	215,334	13,667	0.0609	4307
1998	3,659,809	221,056	6.0%	219,848	13,279	0.0601	4397
1999	3,738,025	240,086	6.4%	219,896	14,124	0.0588	4398
2000	3,850,697	243,511	6.3%	233,163	14,745	0.0606	4663
2001	3,775,144	201,564	5.3%	247,343	13,206	0.0655	4947
2002	3,895,231	247,785	6.4%	249,411	15,866	0.0640	4988
2003	3,913,575	227,573	5.8%	259,767	15,105	0.0664	5195
2004	4,004,765	265,918	6.6%	270,119	17,936	0.0674	5402
2005	4,099,950	264,479	6.5%	298,003	19,223	0.0727	5960
2006[P]	4,095,321	250,918	6.1%	326,506	20,005	0.0797	6530

[12] Ibid.

[13] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK) January 2003.

Transmission and Distribution Losses, Unaccounted for Energy

"Transmission and Distribution Losses and Unaccounted for" (T&D+UFE) is calculated as the sum of total net generation and imports minus total end use and exports.[14] Transmission and distribution system losses, including "unaccounted for energy," are generally defined as a percentage of the difference between total energy input to the network and sales to all customers.

These losses, as the global statistical measure of both technical and non-technical losses, are commonly compared to the aggregate of "Net Generation and Imports" to provide an indication of their magnitude and impact. This comparison is shown in Figure 1-1.

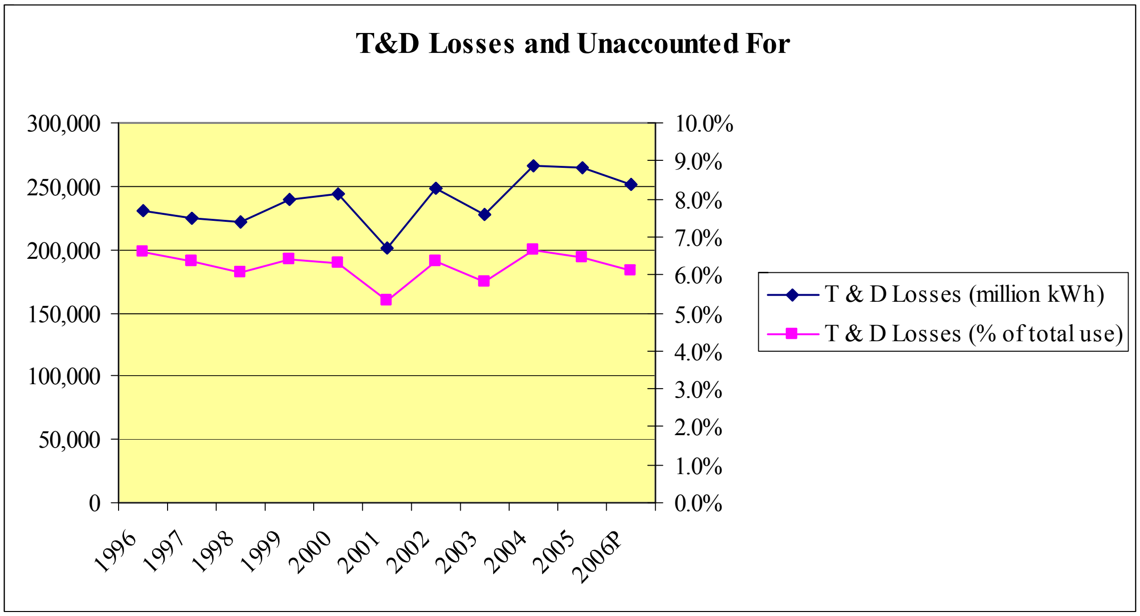

Figure 1-1
T&D Losses

Net Generation and Imports increased from 3.5 quadrillion kWh in 1996 to 4.1 quadrillion kWh in 2006, or 17.4%. Over that same time period, T&D+UFE increased from 230.6 billion kWh to 250.9 kWh, or 8.8%.

The average loss ratio of T&D+UFE to Net Generation and Imports was 6.2% over the eleven years from the beginning of 1996 to the end of 2006.

Revenue and Loss Trends

Revenue increased from $212.6 billion in 1996 to $326.5 billion in 2006, or 53.6%, while T&D+UFE increased only 8.8%. The trend lines for these increases are shown in Figure 1-2. For purposes of this study, it is significant to note that the trend for revenue increases is greater than T&D+UFE. This has a major impact on the importance of revenue loss from non-technical losses.

[14] *Annual Energy Review 2006*, Energy Information Administration, Department of Energy.

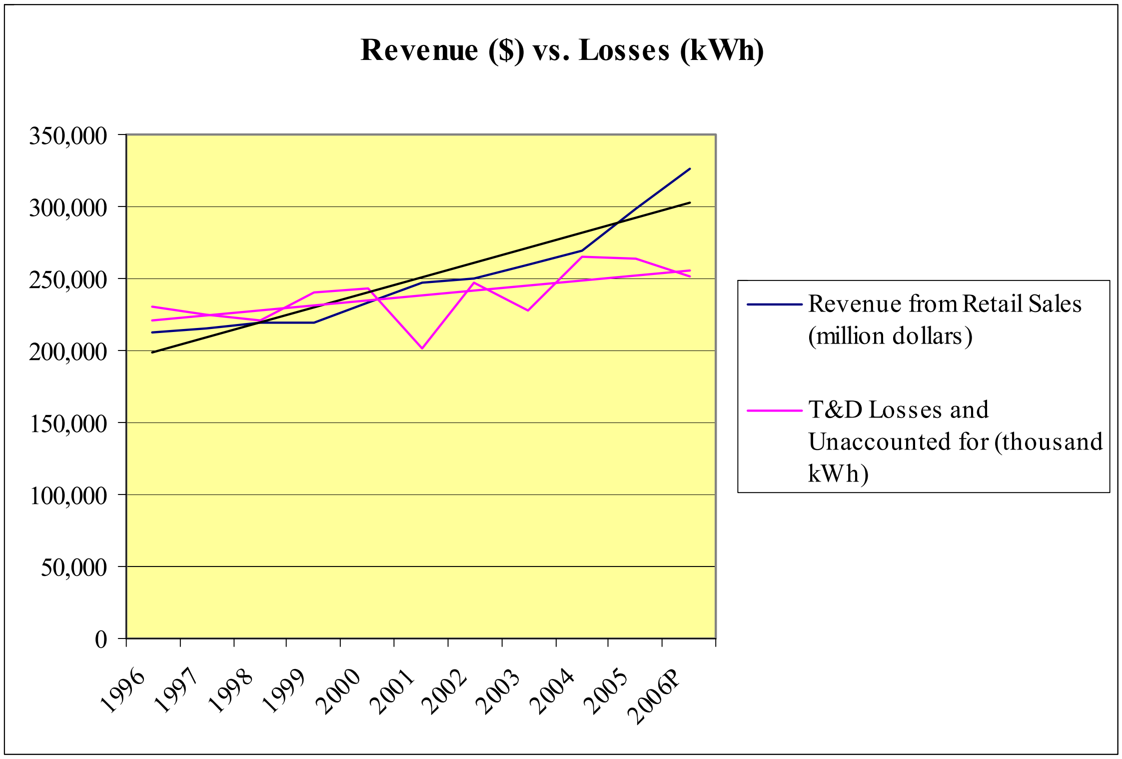

Figure 1-2
Revenue ($) vs. Losses (kWh)

Non-Technical Revenue Loss Estimate

It is difficult to ascertain the extent of technical and non-technical distribution losses separately. The reasons for the difficulty in estimating non-technical losses are discussed in the section on measurement above. For purposes of comparison, and again to get an order of magnitude view of the importance of non-technical revenue losses, a percentage of 2% is most often cited by experts in the industry (Figure 1-3). Applying a constant for the loss ratio, non-technical revenue losses parallel the global.

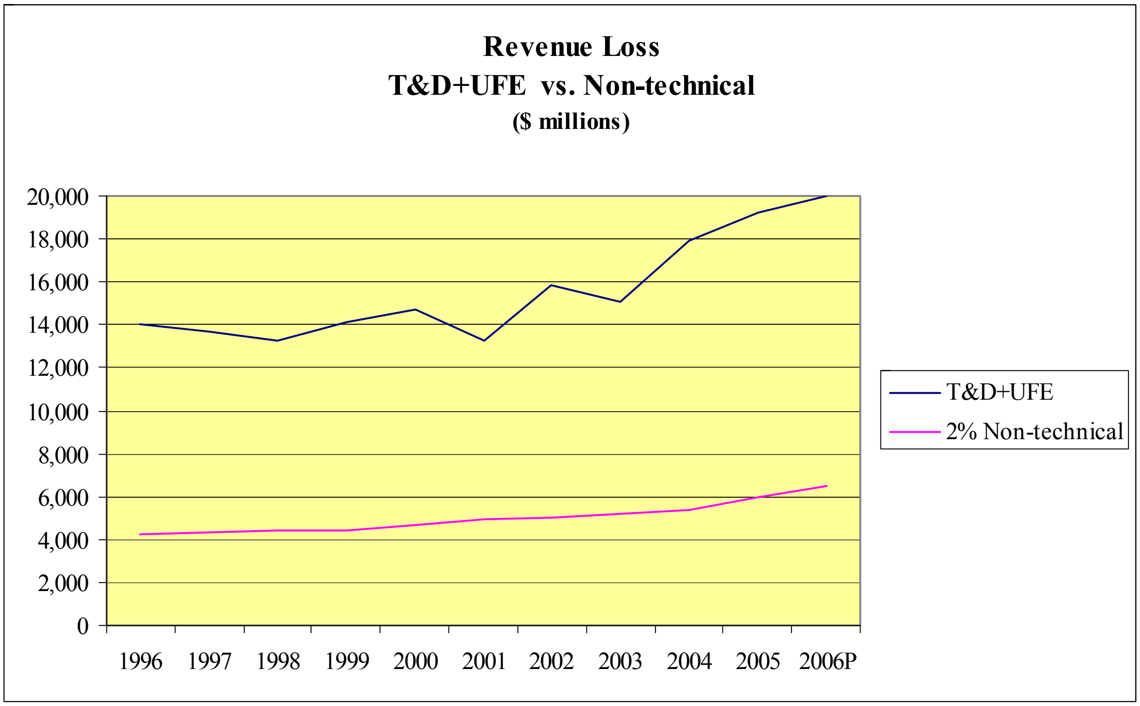

Figure 1-3
T&D+UFE vs. Non-Technical

Revenue Loss per kWh

With revenue rising at substantially higher rates than T&D+UDE losses, revenue loss per kWh is dramatically impacted. Each unit of technical and non-technical losses carries a higher revenue cost, just as each billed kWh carries a higher rate. The upward trend in revenue loss per kWh is shown in Figure 1-4.

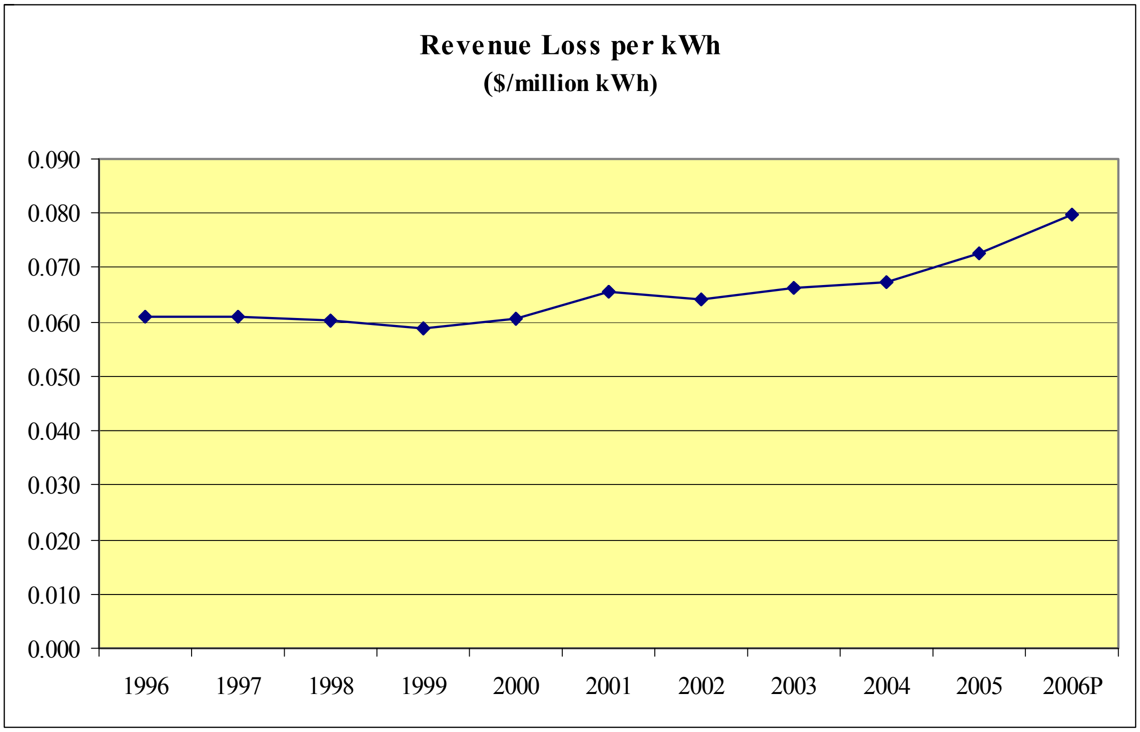

Figure 1-4
Revenue Loss per kWh

Whatever other inferences may be drawn from the data or conclusions reached about technical and non-technical losses, the fact remains that the revenue loss per kWh is increasing. The increases in these losses may be attributable to technical or non-technical components. However, it is most likely that they are more a function of revenue increases themselves. Energy costs have risen over the past decade, and this naturally is reflected in the value of units sold or units lost. Suffice to say, each kWh of reduction in non-technical loss brings the recovery of more revenue today than it did ten years ago.

Assuming that the ratio of non-technical losses to generation remains the same, the value of non-technical losses measured in $/kWh will be higher in terms of revenue. This should be taken into consideration when comparing the revenue losses in earlier studies (prior to 2002) to revenue losses today.

Non-technical revenue loss is greater today than ten years ago, placing greater importance on measures for their reduction.

Studies and Reports

Arizona Public Service Study

After reflecting on several reports and surveys from 1997 to 2000, the Revenue Protection Department at Arizona Public Service (APS) came to the conclusion that "available information regarding energy theft continued to be subjective, at best."[15]

The revenue protection team at Arizona Public Service Company decided to conduct a study of its own.

Two prior studies provided direction and information regarding the amount of various meter problems found in the field and could cite specific percentages. One study by United Energy determined that 2.16% of its meters were faulty. The other study, by the Canadian Electricity Association, found deviations (meter tampering), that would certainly lead to diversion, were definitely occurring across Canada. The average rate for these deviations (tamper rate) was 1.36%.[16]

The goal of the research study at APS was to determine the dollar amount of loss to theft and diversion.

The data in the APS study pointed to a much higher percentage loss among commercial accounts. Of the $7.9 million actual/probable loss, $5.1 million was attributed to commercial accounts. And, similar to the Canadian study, a large number of meter maintenance items were noted. Fully, 6.5% of the meters in the study had some type of maintenance problem.

The APS study concluded that 1.72% of meters were subjected to some form of tampering and that the associated revenue loss was $7.9 million, or 0.518% of revenues.

EPRI Study

The EPRI study on revenue metering loss assessment in 2001[17] concluded that there is "a widespread but unsubstantiated impression in the utility industry that revenue loss from all non-technical sources (excluding bad debt) is between 3% and 4% of utility revenue. Based on this work, we conclude it is far more likely that such losses are between 1% and 2%, and almost certainly are less than 3%. Of course, there will be exceptions in some utility territories. But today's well-managed utility with proactive revenue protection programs should fall below 2%.

[15] *Research Study Quantifies Energy Theft Losses*, John J. Culwell, Supervisor, Revenue Protection Department, Arizona Public Service, Metering International - Issue 1, 2001. January 29, 2001.

[16] Extent of Energy Division on Customer Premises for Canadian Utilities.

[17] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365. This report describes three field studies at three utilities in the United States that inspected meters at over 1000 small- and medium-sized industrial and commercial sites and discusses the available options for utilities seeking to reduce their metering losses.

"Measured in dollars, this gives the following result: A 1.5% average loss corresponds to about $30 million annually for a utility with a million customers and $2 billion of revenue. This equates to about $30 per customer. If the loss is at the upper end of the range, that is 3%, the loss for the same utility corresponds to about $60 million per year, or $60 per customer."

Itron Report to U.S. Department of Energy

In a report submitted to the U.S. Department of Energy in 2005 Itron stated,

"… theft of energy services costs utilities, their shareholders and consumers billions of dollars each year. The consensus estimate among most industry groups and analysts is that energy theft in the U.S. stands between .5 percent and 3.5 percent of annual gross revenues. With U.S. electricity revenues at $280 billion in the late 1990s, theft of electricity alone would equate to between $1 billion and $10 billion annually. A recent article in the Wall Street Journal estimated the nationwide electricity theft figure at $4 billion per year. And with energy prices increasing sharply nationwide, theft of energy services is only likely to increase as consumers struggle to pay energy bills that have doubled or tripled over the past year."[18]

San Diego Gas & Electric

SDG&E demurred from the CPUC Framework for Business Case guidance that benefits from the reduction of theft were non-quantifiable. It proceeded to quantify benefits from AMI in its own business case based on its own estimates of theft. SDG&E claimed $69.4 million in benefits associated with reduced energy theft (both electric and gas), improved meter accuracy, and reduced billing exceptions.[19]

In its opinion approving SDG&E's AMI project, the CPUC stated,

"At the time of the July 2004 Ruling, it was not clear whether energy theft benefits would be quantifiable. That Ruling did not rule out future quantification of benefits. SDG&E has in fact quantified these benefits. We have reviewed SDG&E's calculations of energy theft benefits and find them to be reasonable." [20]

[18] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency,* A Report to the U.S. Department of Energy, Itron. October 2005.

[19] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC, March 28, 2006.

[20] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

However, there was a procedural qualifier:

"It is unreasonable for SDG&E to include benefits which are not within the scope of benefits envisioned for this proceeding and therefore operational benefits should be reduced by $14.5 million."

Further, SDG&E claimed that no more than 0.65% of electricity revenue is lost due to meter error, energy theft, and unaccounted for energy, including meters that fail and mechanical meters that slow down over time as mechanical parts wear out.

In response to a CPUC data request, SDG&E reiterated that many references provide industry estimates for energy theft and all are consistently in the 1-2% range. The explanation for the basis of this figure was that total losses are not known. Field studies at samples of meter sites uncovered approximately that number of incidences of theft, and five sites published studies that report theft in that range.[21]

Hydro One Estimate

Non-technical losses were estimated by Hydro One by reviewing losses from theft, meter inaccuracies, and unmetered energy in other jurisdictions. Based on an overview of the non-technical losses value from utilities across North America, United Kingdom, and Australia, a value of 1.2% was recommended as a reasonable estimate.

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[22]

Published figures for theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold. The upper limit of this range is used in Australia by regulatory commissions as a reasonable estimate in the calculation of distribution loss factors.

"In the past Hydro One has used a figure of 10% of the technical losses to estimate non-technical losses. With technical losses at approximately 6% of energy sold, this represents only 0.6% of energy sales as an estimate for non-technical losses. This is well below (<15%) the published figures for utilities in North America and is less than that used in Australia or most of the United Kingdom. A more reasonable estimate for theft and other non-technical losses would by 1.2% of energy sales."[23]

[21] DRA Data Request Number 15, A.05-03-015, SDG&E Response.

[22] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Caryn Hough.1998.

[23] Distribution Line Loss, Exhibit A, Tab 15, Schedule 2, 2006 Distribution Rate Application (EB-2005-0378), Filed August 17, 2005.

Industry Reports

Industry experts estimate that on average, utilities are losing between 2% and 4% in revenues in the meter-to-cash cycle. Studies on electric and gas meter-to-cash cycle losses, also referred to as non-technical revenue losses, indicate that 80% of these losses can be attributed to theft, defective metering, and soft shutoff policies.[24]

Limitation

Some estimates of loss percentages (for example, the 1.5% figure) seem to be predicated mostly on losses from theft. Most of these loss estimates include only the detection of simple energy theft. There may be thefts that are not detected due to sophisticated bypass.[25] Other contributors to non-technical losses, such as defective meters and billing errors, should be given greater weight when deciding on the most likely percentage. Thus, the 1.5% figure is considered as being at the low end of the estimate for non-technical losses.

Revenue Loss

Considering the referenced studies and reports, statistics and analysis, and the opinions of industry experts in revenue protection, a reasonable percentage for non-technical losses is 2.0%. There are indications that the associated revenue loss might be at a lower level, say 1.4%. Some individual company studies suggest that the ratio for revenue losses is lower than the percentage for energy losses. An opposing argument points to the revenue effect due to higher rates reflecting rising energy costs. Nonetheless, for purposes of this study and for comparisons with other estimates in the industry, applying the 2% ratio to revenue seems credible.[26]

The statistical measures for technical and non-technical losses in terms of energy are relatively constant at around 6.1% in the United States. Although there are reasons to argue that technical losses have increased over the past ten years due to congestion, these technical variances are not thought to be greater than the variance in the ratio for losses using aggregate figures. A major study of transmission and distribution losses would be required to conclude otherwise.

Although the statistical measures do not differentiate between transmission and distribution losses, let alone identify non-technical losses (which are, after all, "unaccounted for"), the ratio for non-technical losses measured in terms of energy units cannot reasonably be larger than 4%, given the relative constancy of transmission losses.

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[24] Ken Silverstein, Editor-in-Chief, *EnergyBiz Insider*.

[25] There are reasons for bypassing the electric system than avoiding payment. One is the concealment of illegal activity. For example, the main source of electrical theft in Canada derives from indoor marijuana grow operations. The Electricity Distributors Association (Ontario) says statistics show grow operators steal an average of $1500 of electricity per kilowatt-hours per day or 10 times the electricity consumption in an average home. Estimates in Ontario, Canada, alone list over a $500 million power theft loss. Reports of seizures of large indoor grow operations list over a 90% electrical theft/bypass rate.

[26] In the absence of industrywide studies of technical and non-technical losses using a consistent methodology, this is a reasonable and sufficient basis for a discussion of the impact of AMI on non-technical losses.

The findings of numerous studies vary widely with respect to the level of non-technical losses, and even more so when imputing non-technical revenue losses.[27] Estimates of tamper rates range from 1.36% to 1.72%. Metering surveys indicate that defective meters may range from 2.16% to 6.5% of the total installed base. Related revenue losses are imputed anywhere from 0.50% to 3.5%. Many of the differences among these estimates derive from analyzing different customer bases and service territories while other differences relate to measurement difficulties with technical losses.

Estimates of non-technical revenue losses range from 0.5% to 4.0% of annual revenue. The 0.5% estimate is so low as to be almost a margin of error in estimation. Most likely, it relates to simple tampering, excluding by-pass and other sources of non-technical losses. The 4.0% estimate is unrealistically high, most likely based on worst-case scenarios.

Non-technical revenue losses most likely fall within a much narrower range: 1.65% to 2.15%, depending on the utility and service territory. Non-technical revenue losses, within this percentage range, over the past ten years are shown in Figure 1-5.[28] A "mode" of 2% would appear reasonable and reflective of the impact on distribution utilities.

[27] Tamper rates and meter defect information are largely taken from surveys, not a complete census of customer bases. These are subject to wide variances, especially between utilities with different customer mixes. With few surveys at a limited number of utilities, it is difficult to apply them on a global scale.

[28] It should be kept in mind that the growth in non-technical revenue losses over the past ten years is a function of both the level of revenue and the non-technical loss rate. Utility revenues have increased significantly over the past ten years with the rise in energy costs. Thus, even while assuming a constant non-technical loss ratio and undertaking vigorous revenue assurance measures, the impact on revenue is increasing significantly. Further, high costs and rates may lead to increased theft by tampering and diversion by changing the risk/reward ratio. High costs make the "reward" more attractive; AMI/MDMS is a resource for increasing the "risk."

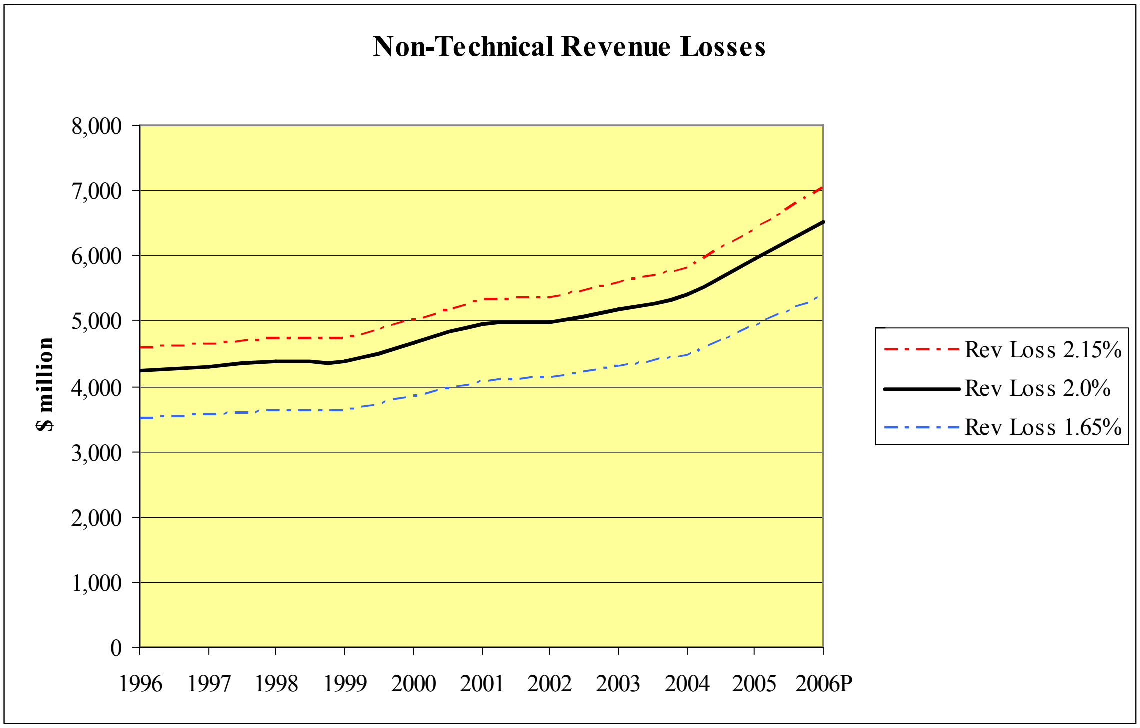

Figure 1-5
Non-Technical Revenue Losses by Year

Based on the 2% rate, non-technical revenue losses are estimated at $6.5 billion for 2006.

International Comparisons

United Kingdom

During the 1980s, some UK electricity companies were losing 2-½% of their total sales because of illegal abstraction (theft) alone. The worst hit areas were London, Merseyside, and Glasgow, with the Northeast having the least amount of theft losses.

Data concerning losses were gained by inter-company comparisons, statistical studies, and engineering studies along with comprehensive studies on street lighting loads to determine distribution system losses and units used in unmetered supplies. This work was underpinned by a number of substation metering exercises whereby meters on particular feeder cables in substations were used to compare the summated meter readings from the properties supplied by those cables.[29]

[29] *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Fellow of the Institution of Electrical Engineers (UK). Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

Overall, Manweb[30] concluded that distribution losses accounted for 5% losses, unmetered supplies (for example, street lights) accounted for 1% losses, and theft accounted for 2-½% losses. This was evidenced by the various studies, metering exercises, signs of serious interference found, and the number of successful prosecutions.

Estimates from four distribution utilities, however, indicate that non-technical losses account for about 3 to 9% of total losses on distribution networks in Great Britain.[31]

Other studies of theft alone in the United Kingdom estimate levels at 0.2 to 1% of energy sold.[32]

Ontario, Canada

Based on an overview of the non-technical losses from utilities across North America, United Kingdom, and Australia, Hydro One considers a value of 1.2% to be a reasonable estimate for Ontario.[33] This ratio is in line with typical losses incurred by other utilities with a similar mix of rural and urban customers in Ontario. However, it may be low when losses from meter bypass in rural areas are fully discovered and accounted for.[34]

Published figures for the level of non-technical losses in North America are very difficult to obtain. In California, "unaccounted for energy" is defined as the difference between the energy purchased and the energy sold in a utility service territory after accounting for imports, exports, and technical line losses. This includes the first three categories of non-technical loss listed above. Estimates from different utilities range from 3.9 to 5% of energy sales.[35]

India

The problem of electricity theft is most pronounced in India, where an estimated one-third of all power is "free." Many users there run their own wires from the distribution lines into their homes. This is a tremendous hazard as the cables are strung through populated alley ways and corridors.

[30] Manweb, a subsidiary of Scottish Power, was among the first electricity companies to gain approval to enter the new market for electricity metering services to domestic and small business customers, which was opened up to competition in June 2004. Under the new arrangements, electricity suppliers have freedom to choose their own agent to collect and process meter readings and to provide and maintain metering equipment. These activities were previously provided on a monopoly basis by the local electricity company.

[31] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[32] *Report on Distribution System Losses*, J.A.K. Douglas, N.J.L. Randles, PB Power report 10025D008, Victoria Australia. February 4, 2000.

[33] *Distribution System Energy Losses at Hydro One*, Kinectrics Inc. Report No.: K-011568-001-RA-0001-R00. July 20, 2005.

[34] Refer to the accounts of theft in Calgary, *Electricity Theft and Marijuana Grow Operations*.

[35] *Comments of the California Energy Commission Staff on the Report on Unaccounted for Energy and Upstream Metering*, Carolyn Hough, California Energy Commission. 1998.

Energy theft costs India's utilities close to $5 billion a year and is the major contribution to operating deficits.

These non-technical losses have costs well beyond the impact on revenue. The revenue losses impact the financial strength of the utility to the point that investments in infrastructure are prohibited. When energy is not paid for, the company is not recovering its costs and, thus, is unable to invest in new infrastructure. The result is regular power cuts. Without these investments, service degrades and further losses—technical and non-technical—ensue. For example, in May 2008 the Maharashtra State Electricity Board of India announced that it has been able to reduce non-technical losses by as much as 8% and says that, as a result, it will be able to reduce power cuts in the state.

United States

Losses in the United States in the 3% range seem low in comparison to India. However, when the related revenue losses are calculated, the number captures the attention of regulators and the electric utility industry. There are losers from non-technical losses in the United States as well as less developed countries.

Distribution Loss Ratios

Distribution loss ratios—calculated from generation to end-user—can be compared internationally (Figure 1-6). For developed countries, the ratio is lower than 8%, with non-technical losses in the range of 1.5% to 3.5%. For countries still developing, the loss ratios are more than double, with non-technical losses (mostly from theft) being the major explanation.

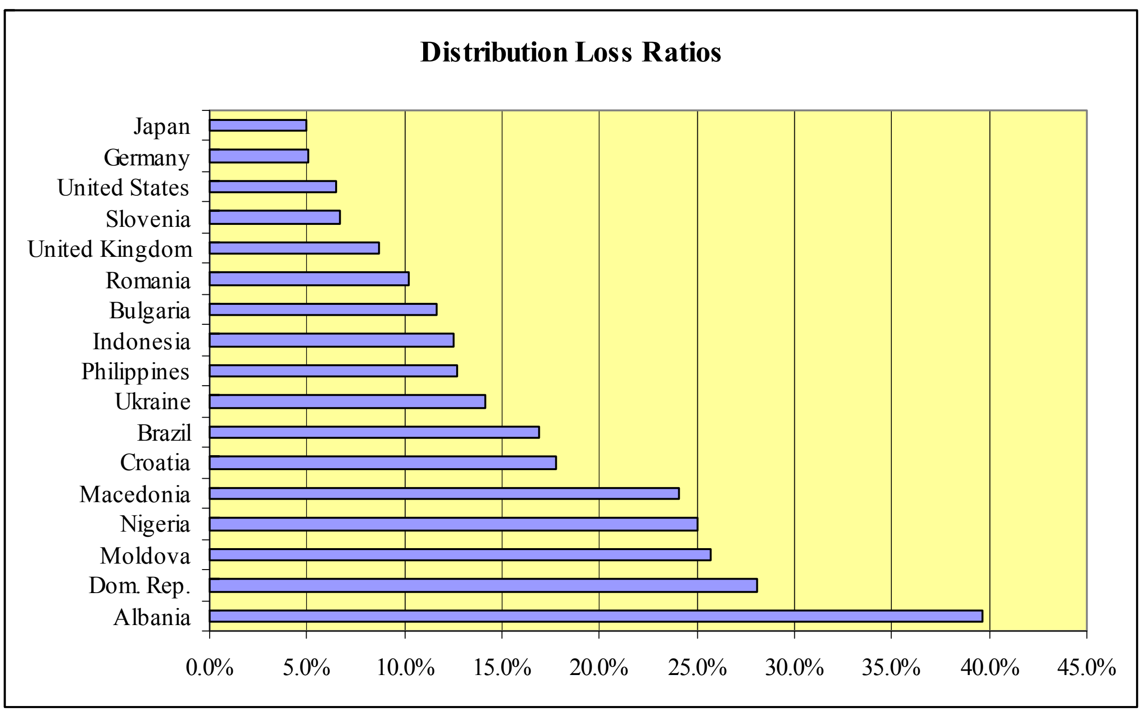

Figure 1-6
Distribution Loss Ratios

Revenue loss resulting from non-technical losses exceeds 40% in many developing countries.[36] Revenue losses of these dimensions have a significant impact on the local economy.[37] It is a problem that governments and utilities must address together. As one observer remarked, "The theft of energy is the largest systematic theft in the world."[38]

Losses Other Than Revenue

Safety

While theft of service is a huge source of revenue loss by any measure, more importantly it poses a serious threat to the safety not only of individuals involved in the theft, but also of utility personnel and the general public.[39] Meter tampering, bypassing, and other means used to steal service place those committing the theft, their families, emergency service personnel, and innocent bystanders in grave danger.

In situations where power must be shut off within a home or business, emergency personnel are at risk of electrocution or burning because meters that have been tampered with may remain "live."

Safety hazards can result in serious injury or death and destruction of public or personal property. These hazards have very real costs associated with them in terms of medical care, loss of productivity, damage to property, and sometimes even services with economic value.

Efficiency

Since losses are factored into the revenue requirement by way of distribution loss factors, and thus included in the rate base, some conclude that there is no real revenue loss to the distribution utility. In this view, reductions in non-technical losses merely shift the source of revenue for the utility among ratepayers. Aside from issues of basic fairness in having some ratepayers bear the burden of non-payment by other users of electricity, the existence of non-technical losses introduces basic inefficiencies into the distribution system.

Non-technical losses have an "efficiency cost." Although a reduction in non-technical losses will represent a reallocation of, rather than a reduction in, electricity consumption, the misallocation of resources introduces inefficiencies. Instead of a direct improvement in social welfare, a redistribution of benefits occurs from those agents whose consumption has been

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[36] *Controlling Electricity Theft and Improving Revenue, Reforming the Power Sector*, Note Number 272, Public Policy for the Private Sector, World Bank. September 2004.

[37] For example, in India electricity theft leads to annual losses estimated at US$4.5 billion, about 1.5% of GDP. The losers are honest consumers, poor people, and those without connections, who bear the burden of high tariffs, system inefficiencies, and inadequate and unreliable power supply.

[38] Kurt W. Roussell, Manager, Revenue Protection, We Energies.

[39] *How Safe is your Utility from Theft of Service?* Revenue Protection Task Force, Energy Association of Pennsylvania. The objective of the Revenue Protection Task Force is to provide education to the public, law enforcement agencies, legislators, and regulators about the facts of energy theft in terms of frequency and quantity of theft.

identified to suppliers and general consumers. However, if consumed units of electricity are correctly allocated, cost signals should encourage a more efficient level of demand for electricity.[40]

The trend toward performance-based rate making highlights the issue of losses where their reduction may change this situation and put in place greater incentives for utilities to reduce non-technical losses.

The reduction of non-technical losses reduces these inefficiencies and rectifies a situation where "lost revenues from energy theft and failure to detect meter errors put upward pressure on rates." Ratepayers benefit when energy theft and meter errors are detected sooner and costs are shifted to the customer who actually used the energy."[41]

Then there is the question of basic fairness. "Although the total revenue requirement does not change through the reduction of energy theft, all law-abiding customers will have lower rates. This is a quantifiable and tangible benefit for our customers."[42]

Technical and commercial losses, however defined, affect allowed tariff levels through a two-step process as shown in Figure 1-7:

Step 1 – Calculation of T&C

$$\text{T\&C} = 1 - \left\{ \frac{\text{Energy Units Billed}}{\text{Energy Units Purchased}} \times \frac{\text{Collection in \$}}{\text{Billing in \$}} \right\}$$

Step 2 – Gross-up Calculation

$$\text{Allowed Units of power purchased} = \frac{1}{1 - \text{T\&C}}$$

Figure 1-7
Calculations

[40] *Electricity Distribution Losses*, Office of Gas and Electricity Markets (UK). January 2003.

[41] *Opinion Approving Settlement on San Diego Gas and Electric Company's Advanced Metering Infrastructure Project*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, CPUC. March 8, 2007.

[42] Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 29, Prepared Rebuttal Testimony of James Teeter, SGD&E before the CPUC. September 7, 2006.

The level of losses, therefore, has a direct impact on the price of electricity consumed. The cost of losses is generally spread out over all users.

It must be noted that the full cost of technical losses on a network consists of not only the value of the electricity lost, but also the cost of providing the additional transportation capacity and the cost of the environmental impacts associated with the additional generation that is needed to cover losses.

Unmetered Demand

Loss in revenue results from the uncontrolled increase in demand from unmetered customers. Also, dissatisfied and angry customers can overload the system, which may lead to faults in the distribution network and load shedding with consequent loss of revenue from customers affected.

Energy Theft Impact on Revenue Ratepayer

Energy theft occurs and is a cost of doing business that is borne by all ratepayers. Any reduction in energy theft from the implementation of automated meters will enable SCE to spread its revenue requirement over more energy sales, thus reducing rates.

Edison Smartconnect™ Deployment Funding and Cost Recovery, Errata to Exhibit 3: Financial Assessment And Cost Benefit Analysis, California Public Utilities Commission. December 5, 2007.

Investigation and Prosecution

The adverse financial impacts of energy theft include lost revenues and the costs for investigation and prosecution. Although these costs are not included in non-technical losses, they are borne by ratepayers nonetheless.

Societal Cost and Theft Comparisons

The public is aware of losses from identity theft, stolen credit cards, hold-ups, and personal robberies. In contrast, the theft of electric and natural gas service, despite the magnitude of the problem, has not received much attention from the public or from regulators.

The cost of non-technical losses in electricity distribution to society can be placed in perspective by comparing it to property crimes.

In the Uniform Crime Reporting Program[43] (UCR), property crime includes the offenses of burglary, larceny-theft, motor vehicle theft, and arson. The object of the theft-type offenses is the taking of money or property, but there is no force or threat of force against the victims. The property crime category includes arson because the offense involves the destruction of property. Property crimes accounted for an estimated $17.6 billion dollars in losses.

[43] *Crime in the US, 2006* US Department of Justice, Federal Bureau of Investigation. September 2007.

Larceny-theft is the crime category closest to theft of electrical services. The UCR Program defines larceny-theft as the unlawful taking, carrying, leading, or riding away of property from the possession or constructive possession of another. Examples are thefts of bicycles, motor vehicle parts and accessories, shoplifting, pocket-picking, or the stealing of any property or article that is not taken by force and violence or by fraud. There were an estimated $5.6 billion dollars in lost property in 2006 as a result of larceny-theft offenses.

The revenue estimate for non-technical losses is $6.5 billion. A comparison of non-technical losses to other thefts crimes is shown in Figure 1-8.

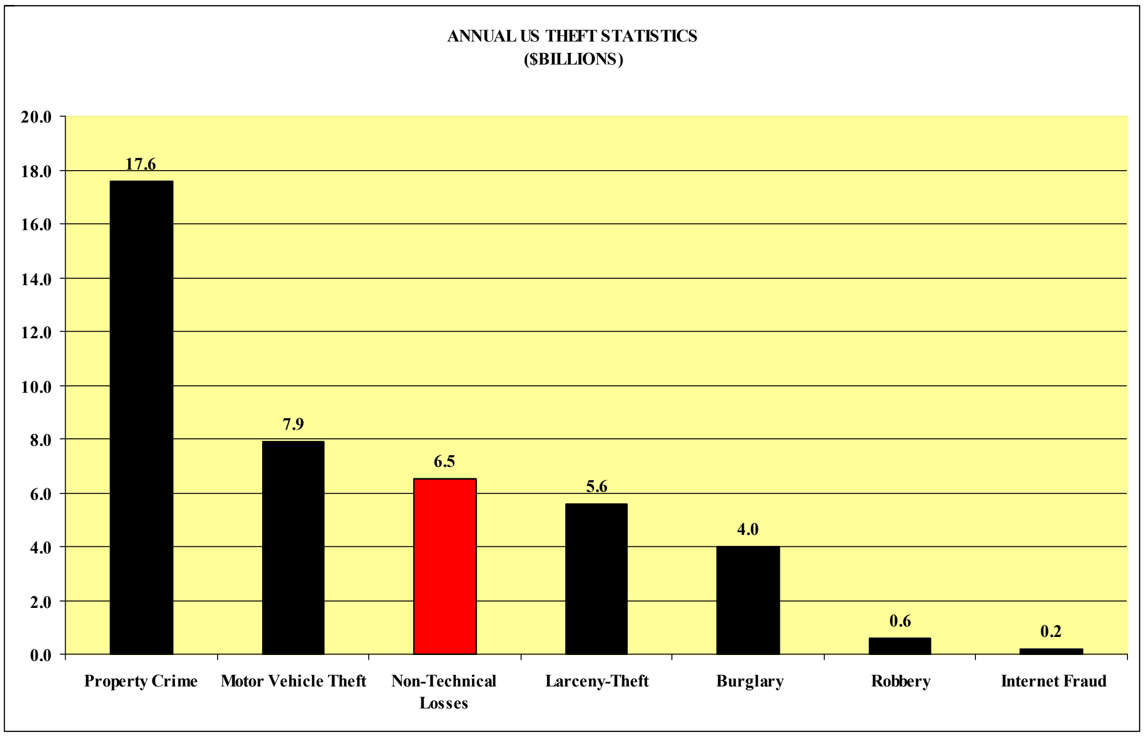


Figure 1-8
Annual U.S. Theft Statistics

2
CHAPTER 2

Revenue Security

"Revenue security" is an apt term to describe the activities intended to protect the distribution system and network resources from external attack or internal subversion, especially theft from diversion by means of "meter bypass." Revenue security ensures that the resources of the electricity industry are available only to those who have the legitimate right to use them. Thus, "revenue security" describes the precautions taken to ensure against non-technical losses.

The activities involved in revenue security are oftentimes called "revenue protection", or more recently, "revenue assurance." Three definitions are presented in the inset below.

Definitions

The term "Revenue Protection" is a colloquialism used by the English-speaking world to refer to the prevention, detection, and recovery of losses caused by interference with electricity and gas supplies.
UK Revenue Protection Association

Revenue Protection is a set of activities to reduce the unauthorized use of energy, ensure metering accuracy and detect meter tampering, and identify customers who fraudulently obtain service.
Kurt W. Roussell, Manager-Revenue Protection, We Energies

Revenue Assurance: A set of activities designed to increase the revenue from providing electric service to ultimate customers, including locating meters without associated customer accounts, relatively high line losses compared with other similar locations, energy theft, and/or improper metering installations.
Federal Energy Regulatory Commission (FERC)

The revenue security function is traditionally performed by utilities' revenue protection departments, using data collected by manual meter reads. The introduction of remote meter-reading technology—beginning with automated meter reading and later including advanced metering systems—changed methods and procedures used for revenue protection, eventually evolving to revenue assurance. These changes in technology and their impact on revenue security are the subject of this chapter.

Meter Readers: The Need for "Eyes in the Field"

The time-honored way of finding electricity theft is through detection by meter-reading personnel. Meter readers are trained and experienced in detecting theft from meter tampering and bypass, and they inspect meters for tampering during regularly scheduled on-site meter reads.

The methods of meter tampering vary from elementary to sophisticated. The ones most commonly detected by meter readers are shown in the insert below.

Common Tampering Techniques

- Stolen meter
- Magnets
- Wire tap on service
- Inverting meter
- Debris, foreign objects inside glass
- Potential link
- Internal—gears, disc, dial hands, adjustment screws
- Load (customer) wires connected to line
- Jumpers—wires connecting line to customer connection

There is some apprehension that AMI, notwithstanding the tamper detection mechanisms in AMI systems, may increase energy theft due to the loss of "eyes in the field" when meter readers no longer visit every meter every month. For example, AMI does not specifically detect and report some kinds of theft, such as taps ahead of the meter.

> "The overall conclusion is that AMR, although it can provide valid and useful assistance in the detection of theft and interference if the system is well thought out and well designed, is not the full answer and that it would be prudent to retain or develop some form of back-up, in terms of conventional revenue protection measures. For instance, one company with an AMR system is considering a new post of Meter Inspector to carry out periodic inspections of customer installations."[44]

There is a concern that AMI—especially after complete meter replacement—will lead to more sophisticated thefts and more bypass, both above and below ground.

Many of these apprehensions and misgivings are founded in experiences with earlier AMR installations. While these are valid concerns, a comparison of AMR and AMI should bring perspective.

[44] OFGEM Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association, Version 3 (final). March 15, 2006.

Comparison of AMR and AMI

Energy theft detection capabilities in AMI systems are far superior to those in simple, first-generation AMR systems. The "infrastructure" in an AMI system includes information systems capable of processing large amounts of interval data for use in discovery of energy theft. This contrasts dramatically with AMR systems, which generally automate only the monthly consumption read.

Prior AMR (not AMI) installations involved tamper alarms so sensitive that false alarms could easily overwhelm the system. Unlike the AMR systems, AMI can intelligently sort and prioritize tamper flags, reducing unnecessary investigations. In addition, AMI, using solid-state meters, is far more tamper-proof than AMR. For example, a solid-state electric meter does not have a spinning disc that can be slowed down. Inverted meters also can be detected quickly through the daily collection of hourly data. Other forms of theft will be discovered through investigation of tamper flags.

AMI solutions involve the retrieval of daily or hourly consumption readings and use database information (comparisons with prior once-a-month readings) to identify locations where theft might be taking place. MDMS applications are essential in the delivery of these solutions. The effectiveness of these solutions is not yet fully documented, as AMI/MDMS have not been deployed on a wide scale over a long period of time. Nevertheless, all indications are that they will be successful when combined with aggressive revenue protection programs with well-trained meter revenue protection agents. With off-cycle reads being supplied through the MDMS, as much as 95% of field service orders for special reads can be eliminated.[45]

Many on-site inspections by traditional meter readers were focused specifically upon meter tampering and meter anomalies, but did not reach more deeply into supply and service wiring where taps and bypasses are likely to be found. AMI reduces the number of routine site inspections and allows the meter revenue protection agent to concentrate on serious issues of diversion.

AMI Contribution to Theft Reduction

After the installation of AMI, it is expected that utilities may uncover a substantial number of previously unknown sources of diversion. Indeed, some utilities are planning to add staff to handle the increased number of theft cases that will be uncovered.

"During the installation period, SDG&E will need six additional Meter Revenue Protection agents to handle the large number of energy theft cases the company anticipates discovering when the new meters are installed. There also will be some transitional costs during the first year to determine the best way to process false positive signals. After AMI installation is complete, SDG&E will require two additional agents to prosecute the large number of energy thefts we expect to uncover."[46]

[45] *Meter Data Management System—What, Why, When, and How*, Hahn Tram and Chris Ash, System Engineer, Enspiria Solutions. August 29, 2005.

[46] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared

With comprehensive AMI/MDMS and vigorous meter revenue protection programs, the most likely outcome is that AMI will bring a reduction in non-technical losses due to theft.

Meter Reader Shortcomings

At the same time, it should be kept in mind that there is an existing level of theft occurring even with manual readers in the field. In some cases, field-level engineers have not been made responsible or accountable for the energy input to their areas, the energy billed, or the revenue. This inattentiveness contributes to non-technical losses.

The personnel best qualified to detect metering problems are often the ones responsible for the faulty metering installation in the first place. In some countries, meter technicians and readers are complicit in meter tampering and bypass.

Meter Defects

Real-time two-way communications offered by AMI allow a utility to detect meter defects that might degrade to failure before the utility could learn about them from manual meter reads at intervals that are often as long as six or twelve months. Furthermore, there is evidence that meter readers miss some amount of meter tampering.[47] There are instances when distribution utilities have discovered meter tampering when deploying AMI that had not been reported by meter readers.

Need for On-site Inspections Post-AMI Deployment

Periodic on-site visits by meter inspectors carefully trained to know what they are looking for are an essential tool in the detection of theft in a post-AMI environment. It is good practice to visit randomly and inspect meters on a recurring basis. Some utilities plan such inspections on a 5-year cycle.

Customers who engage in diversion activities usually act to prevent access for meter reading, and procedures to require and enforce inspection are essential. Traditional meter readers may not be trained for new, more creative methods of energy diversion and must be schooled to recognize the sophisticated tampering methods that may follow the deployment of AMI. In addition, it should be noted that with advanced metering technology, various system abnormalities can resemble power theft. Thus, the staff of revenue assurance departments must have a higher level of training, technical know-how, leadership, judgment, and inquisitiveness.[48]

Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

[47] In an extensive study undertaken in the Merseyside area over a five-year period, Revenue Protection staff acted as meter-reading staff and gained valuable intelligence. It became apparent that meter readers were poor at recording signs of interference with, say, only 1 in 15 of them providing reliable reports. *Theft of Electricity (Illegal Abstraction)*, Comments and Observations, Terry Keenan, Senior Manager, Manweb, Comment on Ofgem's Theft of Electricity and Gas Consultation Document.

[48] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

The transformation from "meter reader" to "meter revenue protection agent" is a core change in the evolution from traditional meter reading to AMI.

> "The old-fashioned methods are dwindling."
> Ron Jones, Residential Meter Services Manager, JEA

Meter Readers

Meter readers read electric, gas, water, or steam consumption meters and record the volume used. They serve both residential and commercial consumers. The basic duty of a meter reader is to walk or drive along a route and read customers' consumption from a tracking device. Accuracy is the most important part of the job, as companies rely on readers to provide the information they need to bill their customers.

Other duties include inspecting the meters and their connections for any defects or damage, supplying repair and maintenance workers with the necessary information to fix damaged meters. They keep track of customers' average usage and record reasons for any extreme fluctuations in volume. Meter readers are constantly aware of any abnormal behavior or consumption that might indicate an unauthorized connection. They may turn on service for new occupants and turn off service for questionable behavior or nonpayment of charges.

Median annual earnings of utility meter readers in May 2006 were $30,330. The middle 50 percent earned between $23,580 and $39,320. The lowest 10 percent earned less than $18,970, and the highest 10 percent earned more than $49,150. Employee benefits vary greatly between companies and may not be offered for part-time workers. If uniforms are required, employers generally provide them or offer an allowance to purchase them.

Tasks

- Read electric, gas, water, or steam consumption meters and enter data in route books or hand-held computers.
- Walk or drive vehicles along established routes to take readings of meter dials.
- Upload into office computers all information collected on hand-held computers during meter rounds, or return route books or hand-hand computers to business offices so that data can be compiled.
- Verify readings in cases where consumption appears to be abnormal, and record possible reasons for fluctuations.
- Inspect meters for unauthorized connections, defects, and damage such as broken seals.
- Report to service departments any problems such as meter irregularities, damaged equipment, or impediments to meter access, including dogs.
- Answer customers' questions about services and charges, or direct them to customer service centers.
- Update client address and meter location information.
- Leave messages to arrange different times to read meters in cases in which meters are not accessible.
- Connect and disconnect utility services at specific locations.

Work Activities

- Documenting/Record Information—Entering, transcribing, recording, storing, or maintaining information in written or electronic/magnetic form.
- Collect Information—Observing, receiving, and otherwise obtaining information from all relevant sources.
- Communicate with Supervisors, Peers, or Subordinates—Providing information to supervisors, co-workers, and subordinates by telephone, in written form, e-mail, or in person.
- Process Information—Compiling coding, categorizing, calculating, tabulating, auditing, or verifying information or data.
- Work Directly with the Public—Dealing directly with the public. This includes contact with customers, representing the organization to customers, the public, government, and other external sources. Information can be exchanged in person, in writing, or by telephone or e-mail.

Bureau of Labor Statistics, U.S. Department of Labor, *Occupational Outlook Handbook*, 2008-09 Edition.

Revenue Protection: Transition from Traditional to AMI

The first step in transitioning from traditional meter reading to remote was AMR, which replaced meter readers with remote meter reading via one way communications. The primary driver for this was savings on meter readers. This introduced difficulties with respect to theft detection. These difficulties were overcome with the evolution from AMR to AMI. AMI, coupled with MDMS, offers considerable advantages with respect to theft detection and the reduction of non-technical losses.

When AMR was introduced, there was an expectation that revenue protection would benefit greatly, and the need for revenue protection analysts and investigators would be greatly diminished. Tamper flags would be the solution. This did not prove out during large-scale deployment. In fact, AMR produced a flood of tamper flags that had the practical effect of being impossible to manage and, thus, being ignored. Except now, the “eyes in the field” were gone.

Most AMR meters have revenue-protection-related features that are useful for detecting novice tamperers, such as reverse rotation (meter being inverted by the customer) and magnetic presence (external magnets placed on meter in an attempt to reduce its registration).

However, there are limitations to AMR’s ability to detect theft by experienced or professional tamperers who seek to defeat the system by installing taps ahead of the meter (for example, masthead), limit the ability to detect “last gasp” while installing bypass behind the meter, or using conventional tactics to slow disk rotation on retrofitted meters. Of course, stolen meters placed in-service by customers are difficult to locate.

Tamper Flag Problem

Several companies that have installed large-scale AMR have experienced problems with tamper flags. AMR has functionality for determining valid flags, but AMR supplies more information than utilities are able to monitor. There are problems with tamper data because of volume and the number of variables that must be taken into account for validation and separating the “urgent” and “genuine” interference cases from false alarms and technical faults. Utilities had to develop their own algorithms for dealing with this.

Further, AMR is not able to cover the types of theft that tamper flags do not report. It cannot detect diversions where the meter is bypassed completely (by “tapping” into the cutout or the wiring from it ahead of the meter). There is no way of detecting this, other than from analysis of consumption. Additionally, AMR is not able to monitor consumption and detect abnormalities which might be due to theft.

The solution to this is offered by AMI and MDMS.

The limited benefit of AMR for theft detection and problems with tamper flags pointed toward the need for MDMS, which only really came into its own later, when AMI was introduced. The awareness of data management requirements, after the experiences with AMR, was a major developmental turning point in the evolution of AMI applications for theft detection and non-technical loss reduction.

AMI provides information for detecting certain kinds of losses, such as detecting recurring tampers from upside-down meters and dial tampering, site and installation diagnostic problems, consumption on inactive accounts, and detailed data for trends and comparisons. However, AMI offers little or no protection from "one-time tampers" (adjustment screws, register tampering, magnetic circuit alteration, electrical circuit alteration or alternations external to the meter, magnets, disk "pinning", stolen meters and, most obviously, taps and jumpers.) These can only be detected using customer modeling (MDMS) and other revenue assurance tools as part of pro-active revenue assurance programs and systems, staffed by well trained and knowledgeable people.[49]

AMI provides a valuable tool to help utilities reduce lost revenue in each one of these areas, but AMI "… is only a tool—it must be coupled with *systems, people, and experience*."[50]

The transition in the detection process from traditional to AMI is summarized in Table 2-1.

Table 2-1
Comparison of Detection Process

Comparison of Detection Process
Traditional vs. AMI

Detection Process		**Change**
Traditional	**AMI**	
Meter readers	Solid-state meters	Improved reading accuracy
Tips/utility hotline	Remote meter reading	Eliminates need for meter reader
Meter-reading reports	Two-way communications	Permits more frequent readings
Statistical analysis	Remote diagnostics	Discovers malfunctioning meters
Proactive sweeps	MDMS	Supports enhanced customer service
Collateral investigation	Meter revenue protection agents	Meter Audits

Transition to Revenue Assurance

In the 1970s and 1980s, these activities were called "current diversion." In the 1990s, they were called "revenue protection." Today, the preferred term is "revenue assurance." Revenue assurance conveys the full meaning of its role in a distribution utility, namely assuring that all the revenue owed the utility is collected.

Revenue assurance includes the following:

- Theft detection and follow-up
- Metering mistakes—for example, malfunctions, meter constants, and billing errors

[49] One study reported an average accuracy of 35% using AMI flags with consumer models. This is much better than AMI flags alone (4%) and better than customer models alone (29%) and is considered a very good "hit rate." *Revenue Protection and AMI Come Together*, Ed Malemezian. June 25, 2007.

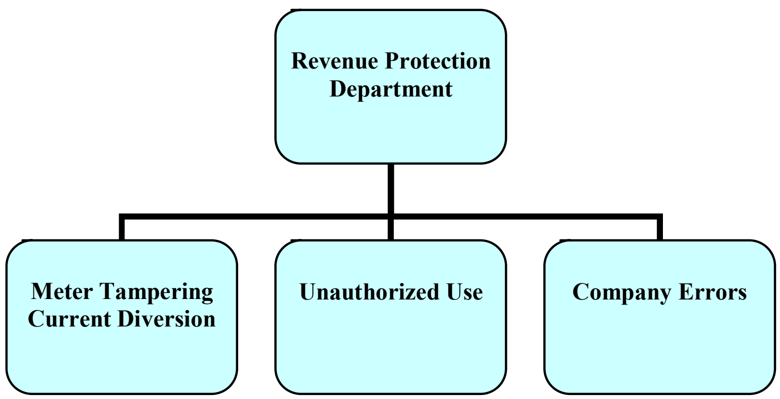
[50] *AMR Tamper Detection—The Good, the Bad, and the Possibilities*, Ed Malemezian

- Consumption on inactive accounts
- Collections

Revenue Protection Department

As revenue protection transitioned to revenue assurance, so did the responsible department and staff. The responsibilities remain the same, namely personnel training (mostly meter readers), receiving information on electricity theft from customers and staff, analyzing consumer load profiles for drastic changes compared to past trends, assessing charges for electricity theft and equipment tampering, and—if necessary—prosecuting clients who endanger themselves or field staff. The main source of information that utilities traditionally use to detect and prevent electricity theft is the meter-reading staff.

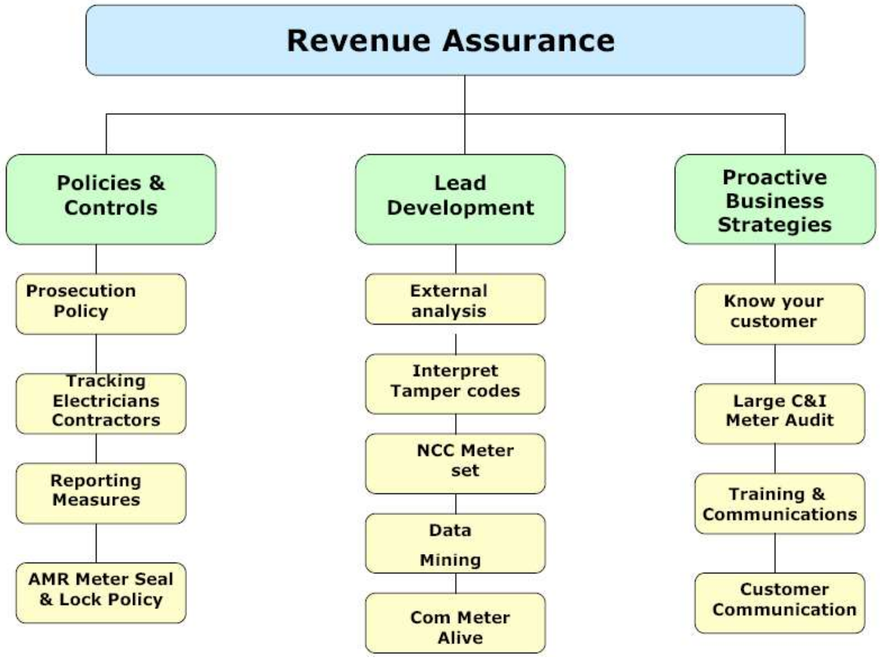
The traditional organization for discharging these responsibilities is illustrated in Figure 2-1. The three major areas where revenue (non-technical) losses were discovered by the Revenue Protection Department were meter tampering and current diversion, unauthorized use, and company errors.



Source: IURPA/WSUTA Conference, Las Vegas, Kurt W. Roussell, Revenue Protection, WEC.

Figure 2-1
Revenue Protection Department

Revenue assurance, on the other hand, is a term that describes the revenue security function as performed with AMI / MDMS. The new Revenue Assurance Department does not rely on manual meter readers—the "eyes in the field." Rather, there is a heavy reliance on policies and controls, lead development using analytical data and customer profiles, and proactive business strategies that include meter audits and customer communications. Meter readers are not absent from this department, but they are no longer depended on so extensively. Rather, revenue assurance with AMI relies heavily on MDMS, analytical tools, and analysts.
The organization of a typical Revenue Assurance Department under AMI is shown in Figure 2-2.



Source: NSTAR

Figure 2-2
Revenue Assurance

Revenue Protection Using AMI and MDMS

The AMI data collection front end detects and reports unexpected usage patterns. Typically, consumption profiles are established for each meter through automatic assignment of profiles using CIS supplied data and manually assigned profiles for specific or temporary situations. Each profile can consist of one or more checks. These checks can be enabled and disabled by the time of the year. They can be used to find diversions for monitoring seasonal meters. Drops in usage can be correlated by power outages for each meter as compared with other meters on the same transformer. All of the applicable checks need to be flexible enough to allow assignment of predetermined percentage changes in consumption, with day of the week and date range selection set up as required for each profile.

The Meter Data Management System (MDMS) receives additional information to aide in more filtering. Typically weather data, utility work order tickets, account status, and limited demographic data are brought in to aide in the filtering. Monthly and daily consumption data are collected and compared on a regular basis against profiles established for each customer. This data can be normalized by weather and other variable parameters. Effective usage is compared against baseline usage to generate candidate lists. These lists are then further filtered by additional information from tamper flags and more advanced consumption patterns to develop suspect lists. The suspect lists are organized and sent to the field for investigation. Various tools are often provided to drill down by customer and groups of customers.

The availability of interval data raises the bar to yet a higher level. Tools to compare actual interval usage against expected interval usage provide a much better picture in spotting the outliers. Advanced statistical techniques are used to generate appropriate algorithms that analyze the data. Science and art come together in making a success of this. Statistics also can be helpful in establishing confidence levels of the suspect lists, allowing the lists to be cranked up or down to match the availability of investigators to do the follow-up work.

Tests by transformer and geography provide another view of customer consumption patterns. When a utility utilizes account-to-transformer mapping, it allows the comparison of usage across similar homes served by the same transformer to look for low usage outliers, and to correlate changing usage patterns with blinks, reverse rotation, or other events. This mapping also enables comparison of transformer load to aggregated usage, if the utility installs additional interval meters upstream of the utility transformers. When meter data is supplemented with data from other sources, more views and points of comparison can be created. Examples include creative mining of other CIS fields such as the SIC Code or Customer Name to find groups of customers with similar names.

The Revenue Protection application receives all relevant data from the utility CIS, historical and present temperature data from an internet based source, triggered flags from the AMI tamper database, geographical information from external sources, SIC codes and NAIC codes from CIS, demographic data from paid or public sources, operating hours from public sources and feet-on-the-ground research, as well as daily and interval consumption data from the utility AMI or MDM systems.

Profiles and consumer models are built from sets of flexible rules. These are assigned to each account and analyzed on a regular basis. Tools include the ability to drill down by customer or group and to score each deviation from expected consumption patterns by numerous methods. Candidate lists and suspect lists are managed, and feedback is provided for both tracking results and improving the process.

Revenue Protection and AMI Come Together, Ed Malemezian. June 25, 2007.

MDMS Theft Reports

With the advancement of AMR/AMI, the traditional approach of identifying potential theft with a meter reader's visit to the site is becoming obsolete. Aided by MDMS, data analysis provides leads based on usage patterns and other data.[51] This is proving to be an effective approach to identifying theft.[52]

MDMS is used to turn AMI data into leads that can be followed up by revenue assurance teams. MDMS provides "automated exception processing" reports. An exception is when the system sees an event or data circumstance that it is not expecting. Examples with revenue-assurance relevance include meter readings that show lower consumption than expected, meters that do not report any consumption, and readings that show power being used at a supposedly vacant premise.

"Plus or minus 20" reports look at accounts where consumption has gone down by at least twenty percent. Data is reviewed over a thirteen-month period, ensuring that the information reflects seasonal usage patterns.

Another approach looks for unusual usage patterns, such as usage that drops off substantially on weekends. Through the MDMS, utility managers can compare unusual usage reports with power-outage and restoration reports that narrow down dead-end leads. This lowers the cost of collection.

Examples of Reports Using AMR/AMI Data[53]

- An "unplanned outage" report spotlights accounts with more than 10 outages in 30 days. About 40 percent of PECO's theft detection stems from this report.
- A "billing window" report detects meters turned on or off close to the billing period, indicating attempts to force low-balled estimates or pay for only a few days' worth of consumption. This report pinpoints around 35 percent of the utility's theft.
- A "reversed meter" report finds power-out and power-up messages that occur in quick succession if the customer unplugs the meter, then plugs it in upside down to make the register run backward. About 20 percent of PECO's theft shows up via this report.

[51] AMR / AMI tamper indications are analyzed with detailed consumption data, outage information, tickets from work order systems, and numerous external demographics. Advanced analytics are used to establish baseline patterns and profiles for customer accounts. Outliers can easily be identified and followed-up according to procedures established by the revenue assurance department.

[52] For example, at NSTAR, revenue protection billings increased more than 130 percent, while the cost per case processed decreased by 25 percent. The improvement was due to leveraging the lead generation partnership and streamlining the process with automated reports, fewer handoffs and triage of theft cases. *Reducing Revenue Leakage*, Penni McLean-Conner, NSTAR. Electric Light & Power, July 2007.

[53] *Deputizing Your Data: AMI for Revenue Protection*, Betsy Loeff, Electric Power and Light.

AMI Remote Service Disconnect

In certain instances, utilities incur losses when customers leave without disconnecting. In these cases, the utility has active accounts without contracts. Oftentimes, it would take utilities a minimum of thirty days to find active accounts with no contract. This produces non-technical losses.

With AMI, service cut-offs can be "virtual," without dispatching a field service technician to the site. Instead, the utility takes a reading through the AMI system, sends a final bill to the departing customer, and leaves the premises ready for the next resident.

Sometimes the new resident does not call to set up an account after moving into a house or apartment. In these instances, a consumption threshold is set up. Once the threshold is surpassed, the MDMS automatically generates an order for a field service technician to shut off service.

Key Attributes for Revenue Protection—AMI + MDMS

Advanced Meter Infrastructure

- Full two-way communications
- Advanced meter capabilities with extensive diagnostics
- Exponential increase in meter reads and meter data
  Example (500,000 meters):
  1 monthly read = 500,000 reads/month
  1 daily read 500,000 reads/day, 15 million reads/month
  1 hourly read 12M reads/day, 360 million reads/month

Meter Data Management Systems

- Systems to create reports that analysts/investigators can use to research, investigate, and take corrective action
- Energy Diversion will become more innovative with smart metering (without manual meter reading). Data and analytical tools must be used to "outsmart the thieves"

Pros

- Better knowledge of unbilled revenues
- Notification of illegal reconnects
- Ability to examine consumption patterns from daily read information
- Ability to examine 15-minute interval data

Cons

- Loss of regular field visits to examine metering equipment
- Inability to determine connections ahead of the metering scheme
- The meter will tell you only what it sees—not what it doesn't see
- Unless additional services are known, unmetered (unbilled) revenue can occur for years
- The combination of these factors along with the rising cost of energy increases the potential for revenue loss significantly

Source: *Various Applications of Electric Metering & How They Relate to Revenue Protection*, Guy Cattaruzza United Illuminating NURPA. September 19, 2007.

Billing and Customer Service

Along with theft, the billing and customer service problems encountered by traditional manual meter-reading operations are contributors to non-technical losses.

Traditional Billing System[54]

Currently, meter readers travel to customers' meters each month to collect customer usage information (meter reads) with a hand-held data collection device.

These meter reads are used to prepare monthly bills. After the meter-reading route is completed, the customer's meter reads are transferred from the hand-held device to the customer information system. This data transfer must be done at a meter-reading base location. Back-office billing systems then perform a series of data validation routines that will, if warranted, automatically trigger a pre-billing review that may result in bill adjustments. The largest number of bill adjustments is due to meter-reading error.

When customers move from one residence or business to another, field service personnel must visit the meter and complete a "close order" or a "change of account" order to obtain the "end read" for the departing customer and a "start read" for the new customer. A certain number of these orders are "revert to owner" reads where service is left on for the convenience of property owners or managers when a tenant moves. Also, when meter-reading errors are suspected, field service must perform a "read verify" order at the customer's meter.

Billing System with AMI

AMI eliminates field visits as part of the billing process. Instead, utilities obtain meter reads electronically on the date a customer desires rather than on a service order schedule, which is subject to delay due to workload constraints. This reduces error and, thus, non-technical losses. It also improves customer service.

To prevent billing errors, once meter data is captured the billing system performs a series of billing edits prior to sending the customer bill. Despite comprehensive edits, some billing adjustments are required after bills have been sent. Other anomalies (billing exceptions) also are detected after completion of the billing cycle, such as meters in "off" status but registering consumption (OBR), meter failures, and unauthorized energy usage theft. With AMI, many of these billing exceptions will be eliminated and others will be detected more quickly, thus reducing non-technical losses.

Estimating

Estimating is one of the defining issues for which AMI offers a solution and contributes to the reduction of non-technical losses.

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[54] *Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection*, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, Application 05-03-015, Chapter 3, Prepared Supplemental, Consolidating Superseding and Replacement Testimony of James Teeter, SGD&E before the CPUC. March 28, 2006.

The vast majority of utility customers receive a monthly visit from their utility's meter reader. This meter reader visually reads the electric and/or gas meter, then forwards that information to the utility's billing office to generate a monthly consumption bill. If the meter reader is unable to access the meter,[55] most utilities will proceed to estimate the electricity consumption based on previous usage and recent weather patterns. They will then use that estimate as the basis for the next bill.

Exception reports are another area where estimates are made. After data are collected, they are analyzed, looking for exceptions such as missing reads, zero consumption, idle with consumption, out of range readings, and negative consumption. These transactions are placed in an exception file for review. Actions taken by revenue protection to correct the exceptions include reading, re-reading, checking for malfunction, checking for tampering, or accepting the read and estimates.

It is not uncommon for utilities—particularly those in higher-density urban areas—to estimate ten percent, twenty percent, even thirty percent or more of the meter reads each month for billing purposes. This practice leads to inaccurate billing, increased customer complaints, and higher costs for utilities to investigate and resolve those complaints.

AMI Solution to Estimating

AMI provides accurate, timely, and reliable information about energy use and demand that offers a solution for estimating.

AMI minimizes meter access problems, limiting them to meter installation and inspection upon suspicion of tampering or diversion. AMI eliminates estimated reads and improves meter-reading accuracy, which results in improved billing accuracy, fewer customer complaints, reduced call center traffic, and improved customer service.[56] Further, AMI reads remotely interrogate meters daily, rather than monthly. This identifies bad meters more quickly and avoids much of the estimating.

Thus, AMI offers a solution to estimating, which contributes to the reduction of non-technical losses.

Security

AMI avoids the security risk of giving keys and access to premises to meter readers. This is a concern of high importance in these security conscious times.

[55] A meter cannot be read when it is located in the basement and the consumer is not home; the yard is fenced with a locked gate and a dangerous animal in the yard; customers are threatening or hostile; extreme weather; or when the meter is dead, damaged, or missing.

[56] *The Critical Role of Advanced Metering Technology in Optimizing Energy Delivery and Efficiency,* A Report to the U.S. Department of Energy, Itron. October 2005.

AMI + MDMS Solution: Importance of Information Technology

A comprehensive revenue assurance program is based on AMI and MDMS.

This constitutes a "holistic approach to revenue recovery"[57] that combines expert analytical resources, data analysis software, internal utility customer asset data, and external data sources. This involves identifying data flow requirements and providing solutions to ensure timely and accurate billing. This requires the effective integration of AMI and MDMS with existing data systems in the utility.

Information Technology Integration

IT integration is a major participant in the transition from traditional meter reading and revenue protection methods to AMI and comprehensive revenue assurance programs. It's importance is underscored by the level of investment in most AMI programs. Indeed, back-room office applications are a large portion of the total AMI investment, ranging from a low of 5% to over 30%. IT integration is essential to the management and reduction of non-technical losses after the transition to AMI.

IT heavily influences the success of the AMI program and the integration of information systems using new MDMS that is essential for the success of the AMI program. The IT integration plan includes five major systems:

1. Meter Reading
2. Meter Inventory Management
3. Work Order Management
4. Customer Information
5. Revenue Assurance

Integrating these systems is a substantial and complicated task. This requires a high level of commitment from IT stakeholders.

When AMR systems were installed, primarily for savings in manual meter reading, IT integration was not a priority. However, when the data flows (such as tamper flags) became overwhelming, utilities needed applications to manage them. These were often provided through *ad hoc* custom programs developed internally by IT departments.

For this reason, it is advisable to include IT stakeholders from the beginning when making the transition to AMI. The commitment should be in terms of the project, resources, change management, and setting expectations for results. Commitment from IT stakeholders dramatically affects the success of the transition and results in reducing non-technical losses, both at the time of installation and throughout project life.

[57] *Discovering Unaccounted-for Energy with the Revenue Assurance Service*, Patty Seifert, Revenue Assurance Product Manager, Itron. 2007.

Revenue Assurance and IT Integration

The advent of AMI brings a total change to the conduct of revenue protection. If not preceded by AMR, the most obvious change is the elimination of manual meter reading as the primary method of data collection on meter tampering and theft.

Without the benefits of manual meter readers, revenue protection must supplement AMR/AMI with meter data management systems to compensate for the loss of functionality previously provided by meter readers. This involves integrating MDMS into the customer information system. The combination of data from AMR/AMI, MDMS, and customer information system (CIS) can be used to generate leads and profiles for target areas and customers.

Revenue Assurance, Metering & IT business units must come together early, prior to the deployment of AMI, to form a team separate from the deployment itself to develop a Revenue Assurance Transition Plan.

Transition to AMI—Information Technology Issues that Impact Revenue Protection

- System reliability, data backup and disaster recovery
- Reporting / monitoring capabilities
- End of day vs. real-time 24/7
- Exception handling
- Secure access
- Customer information system integration
- Work order file definitions
- Customer data file management
- Meter reading / billing window (“blackout”)
- Test and validation of upload/download processes
- Meter-reading systems integration
- Migration path
- Project size, schedule,and budget

Bob Donaldson, PE, PMP Progress Energy Carolinas Project Manager, Mobile Meter Reading.

Theft and Enforcement

New Methods of Theft

A major risk of realizing the full benefits of AMI for revenue protection is posed when customers learn to divert energy in new, unknown ways. Given historical data from AMR installations, this risk does not appear too great. Also, AMI endpoints have software and tamper sensors that are more sophisticated at detecting theft. Enhancements to back-office systems with new algorithms and heuristics to identify new types of theft are continuously being developed. Nonetheless, most certainly the ingenuity of a few customers will lead to some new types of theft. Distribution utilities need to be alert to new possibilities for theft and take them into account in their revenue protection strategies.

"The western countries and India have treated this as a criminal offence. But crooks always have the ability to keep one step ahead of the theft detection system. They stay in business purely through their flair to overcome any challenge that comes their way. They will find ways to be ahead of any anti-power theft detection system and will try to hoodwink the vigilance wing. Gone are the days of crude mechanical ways to tamper with the meter or divert electricity from main line. The R&D of electricity theft is moving faster than that of the best metering mechanisms, which was revolutionized with the advent of ICs and programmable logic circuits. Sharp minds frame laws and invent technologies; sharper minds find loopholes in it. Now power theft using the remote sensing devices, tampering of crystal frequency of integrated circuits; theft using harmonics, etc. have been developed."[58]

Customer Perception and Motivation

Far from deterring customers from theft, some distribution utilities have reported an increase in occurrences after AMI installation. Once some customers are aware that meter readers are no longer calling, they think that there is less likelihood of being caught. The technical aspects of dealing with advanced electronic metering are no deterrent. There is a wealth of data available on the internet on how to interfere with meters. Even consumption monitoring is not the full answer. Clever thieves know that they should gradually reduce consumption over a period to avoid detection by the relevant "filters."[59]

One new class of customers that are wittier than thieves in the past and have new motivations are "grow operations." These customers—the illegal growers—are motivated not by saving on electricity, but by not being detected as customers. This is a major source of non-technical revenue loss in Canada and parts of California.

AMI can be helpful in detecting theft by this new class of customer. An example from Sacramento, California, is noted in the following quotation.

"Energy theft is not high at all, but we have experienced a significant number of 'grow houses' springing up in the area. We see AMI assisting us in finding these houses from a transformer load perspective—it will tell us that we're sending out X amount of kWh and only billing for Y amount, and alert us to a potential problem."[60]

AMI systems that are deployed at the substation transformer and feeder level are particularly effective in detecting these thefts.

Enforcement

As the attention of regulatory bodies and the public is drawn to energy theft, new and better methods for detecting and finding instances of theft will be called for. AMI has much to

[58] *Pilferage of Electricity—Issues and Challenges*, G. Sreenivasan, Assistant Executive Engineer, KSEB; guest faculty, Engineering Staff College of India, Hyderabad.

[59] OFGEM *Consultation on Domestic Metering Innovation, Response by the United Kingdom Revenue Protection Association*, Version 3 (final). March 15, 2006.

[60] Erik Krause AMI project manager, SMUD

contribute to these methods. AMI offers significant tools to expedite both discovery and resolution of theft cases. It can be used to build intelligent databases for identifying trends and potential factors influencing future theft strategies and targets. This is an ongoing endeavor.

AMI makes more aggressive enforcement programs possible by 1) identifying high-probability targets for investigation and 2) gathering more evidence and constructing more convincing cases.

Meter bypassing can be proved only when it is observed at the time of inspection. The consumer can erase all traces of theft if the inspection is known in advance. This is a significant problem in many developing countries. AMI can help identify customers and locations with a high probability of meter tampering and diversion, thereby increasing the chances to observe theft.

Investigating Power Theft

Utilities often initiate probable cause investigations after a meter reader detects a broken seal or other indications of tampering. The meter reader reports the condition to a supervisor or power theft investigator, who then conducts the investigation. At this point, some utilities will contact their local law enforcement agency and an officer will accompany the utility investigator during the initial investigation.[61]

If the investigator finds evidence of tampering, evidence is collected and reports are prepared. The utility maintains the evidence and provides supporting documentation.

Evidence and Prosecution

Before a utility can file charges against a potential suspect, it must gather the following as evidence, documents, and appropriate statements:

- Tampering devices—These could include straps behind the meter, wires used in a bypass system, or other tampering devices or equipment relevant to the case.
- Meter report—This report shows that the meter was operating correctly when installed and demonstrates how the particular tampering method used would have affected the metering of electricity.
- Witnesses—These are witnesses who provide testimony. They include the meter reader who initially detected the possible diversion, the utility investigator, and the police officer who conducted the investigation.
- Account billing history—This report illustrates the time the theft began and the amount and cost of the stolen electricity.

Without manual meter reading and field service personnel, AMI and MDMS are now expected to provide much of the required documentation for theft investigations. With AMI, this documentation can be much more detailed and present more persuasive cases. For example, most utilities have account billing histories on each account's consumption and billing records on

[61] *Power Theft: The Silent Crime*, Karl A. Seger, and David J. Icove, FBI Law Enforcement Bulletin. March 1988.

a month-by-month basis. AMI provides information on a daily and hourly basis. This is necessary to detect more sophisticated theft techniques, such as "on offs" during the day.

The burden of this documentation is one reason that utilities prosecute only about 10% of cases.[62] The burden can be lessened considerably by using the data that AMI generates and the ability of MDMS to organize it into useable formats for preparing complaints for use by prosecution.

Installation Effect

AMI deployment requires replacing legacy meters with new meters that include two-way communications and diagnostic capabilities. This is a one-time opportunity to significantly reduce non-technical losses due to meter defects, theft, and billing.

> "AMI provides the opportunity for a 100% clean sweep."
>
> Ed Malemezian

Meter Defects

Although theft is a major source of non-technical losses, a significant percentage of non-technical losses arise from factors that utilities can control, especially those related to meter damage, failure, and errors.

"Although, numerous published papers imply that all revenue losses are a result of customer mischief, this is far from true. This project found that, at least in the small industrial and commercial sector, utility operations themselves are responsible for the larger share of lost revenue. Equipment failure, non-malicious equipment damage, incorrect meter constants or 'CT' ratios, meters in need of recalibration, etc. all contribute to revenue loss."[63]

These are largely due to problems with maintenance issues of electromechanical meters nearing the end of their useful life and the tendency of electromechanical meters to run slower as they age. The replacement of legacy electromechanical meters with electronic metering, as part of AMI deployments, should substantially mitigate this source of loss.

The installation of AMI itself, and the replacement of obsolete meters, will contribute greatly to the discovery and remedy of this source of non-technical loss.

A large proportion of meter problems, and nearly all of the failures, will be remedied by a competent AMI deployment that re-installs all meters. Finally, for the life of the AMI system, the AMI-equipped meters will detect and report many types of energy diversion and meter tampering.

[62] Ed Holmes, Senior Consultant, Arnett Industries.

[63] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Some existing meters may be within the permitted accuracy tolerances and still under-register consumption. This is so small that it is not cost-effective to change the meters on an exception basis. However, the AMI deployment replaces every meter anyway, and brings aggregate meter plant accuracy very close to 100%. This benefit will be long-standing because solid state meters have no mechanical wear or friction and do not slow down over time. Sometimes dead meters are found during meter replacements. "Dead meters" are not caught by "no consumption" reports because they usually occur on the percentage of meters that are not yet converted to automated metering.

Inspection

A full AMI deployment provides the opportunity to inspect, find, and correct tampering that has been in place for a long time—100% inspection. However, to be effective, AMR installers must be properly trained and incentivized to take the time required to discover, record, and report tampering.

The entire service entrance facility, not only meters, must be inspected. The importance of inspection to the reduction of non-technical losses is shown in the following statement.

"Utilities that take the time to thoroughly inspect the entire service entrance facility, as well as the meter and meter socket themselves, at the time of AMI equipment installation have the opportunity to minimize otherwise lost revenues."[64]

Some methods of energy theft, such as meter bypass, meters turned upside-down, and meters with drilled holes or adjusted dials, are not necessarily seen by meter readers during their monthly meter-reading cycle visits. Since AMI offers total meter replacement, almost all simple energy theft will be uncovered during the installation of the new meters.

Meter Change-outs

As the volume of AMI-related meter change-outs increases, timely synchronization of meter changes with customer account data becomes essential to help a utility avoid large numbers of billing system rejections caused by incorrect meter assignments. MDMS helps to minimize the number of incorrect and estimated bills that result from the change-out process, thus avoiding billing errors that can contribute to non-technical losses during AMI deployment.[65]

Billing Transition Period

When new meters are installed, a number of data elements must be recorded properly to set up the billing systems. Additionally, new data about meter communications are typically required (such as AMI communication module serial numbers). The installation of AMI offers the opportunity to consolidate databases from multiple sources into a fully integrated MDMS.

[64] Interview with Ed Holmes.

[65] This is particularly important with large-scale AMI deployments that can take from three to five years.

MDMS provides benefits to utilities during AMI implementation by helping to identify and track meter installation problems and verify that data received from endpoints is sufficient for customer billing. If installed as part of the AMI meter installation, MDMS can be used to process data for billing. MDMS can be used for validation, estimation, and editing in the billing process during installation. Interval data provided by AMI systems may have gaps and/or errors. The MDMS system can be used to fill in the gaps and correct the errors in the data.

The AMI installation period offers an opportunity to create customer profiles that compare usage patterns before and after AMI installation. The identification of possible theft in the past is an indicator of theft likelihood in the future.

GIS Mapping

AMI requires that meter asset data is maintained timely and accurately. Meter asset data, including meters and communication modules, must track assets from acquisition to inventory to field installation and provide accurate meter-to-customer and meter-to-network connectivity information. This often requires consolidating and enhancing existing meter applications, including those in meter test, inventory, AM/FM/GIS, and customer information systems. These issues must be addressed at the time the AMI system is installed.

Geographic information system (GIS) mapping during AMI installation provides a valuable resource for revenue assurance. AMI installation offers an opportunity to integrate a GIS system with the customer billing system. This is an effective tool for detecting theft at consumer, distribution transformer, and feeder or substation levels. Analysis of patterns of individual consumption over GIS can help in identifying the sources of theft.

Energy Diversion Program

Utilities can take advantage of the replacement of meters to refresh their energy diversion programs, as well as public awareness of the issues and penalties.

Distribution utilities that have some type of revenue protection program in place can update their program and institute more aggressive programs using a combination of the AMI, MDMS, and teams of newly trained field inspectors.

For distribution utilities that do not have an energy diversion program, AMI installation is an opportunity to institute one at low cost.

AMI Planning and Transition

The revenue protection department staff should be included in the AMI project team from the beginning of the planning process. These individuals can offer valuable insight on many pertinent issues, ranging from a customer's behavior to billing (the integration of databases in the MDMS) to collection. Most importantly, they have the experience to help train meter installation teams and monitor the testing and installation of the meters themselves. They are an important part of the transition to AMI. Their participation can contribute greatly to the realization of potential savings from AMI and the reduction of non-technical losses.

The transition itself—replacement of meters, analyzing customer profiles, testing, system development, algorithm development, and customer profiling—probably has the greatest impact on revenue security and the reduction of non-technical losses.

3
CHAPTER 3

AMI Technologies to Detect Non-Technical Losses

AMI offers many technologies for the detection and reduction of non-technical losses. These technologies can be divided into two main categories, hardware and software, as outlined in the following insert.

Hardware – metering technology

- Meter accuracy
- Tamper detection
- Remote testing diagnostics
- Remote connect/disconnect

Software-based applications and tools

- Meter data management systems
- Statistical analysis
- Geographical information systems

These technologies can be used alone or, preferably, in combination with one another for enhanced effectiveness and manageability.

In this chapter, these technologies will be discussed in the context of their relevance to non-technical losses.

Importance of AMI Technologies to Detect and Reduce Non-Technical Losses

The relevance of the technologies for the detection and reduction of non-technical losses is evidenced by the functions and uses that utilities consider most important as part of overall AMI deployment.

As part of the FERC report[66] on demand/response and advanced metering, FERC staff conducted a survey of utilities.[67] Respondents were asked how they used their systems and which functions

[66] Section 1252 (e) (3) of the Energy Policy Act of 2005 (EPAct 2005) requires FERC to prepare a report by appropriate region that assesses electric demand/response resources.

[67] *Assessment of Demand Response and Advanced Metering Staff Report*, Docket AD06-2-000. FERC. August 2006. In preparing this report, Commission staff developed and implemented a first-of-its-kind, comprehensive national survey of electric demand response and advanced metering. The FERC Demand Response and Advanced Metering

are provided by the AMI systems. Specifically, the FERC survey asked organizations that have installed AMI systems[68] to identify which of the following possible AMI features they used:

- Remotely change metering parameters
- Outage management
- Pre-pay metering
- Remote connect/disconnect
- Load forecasting
- Reduce line losses
- Price responsive demand/response
- Enhanced customer service
- Asset management, including transformer sizing
- Premise device/load control interface or capability
- Interface with water or gas meters
- Pricing event notification capability
- Power quality monitoring
- Tamper detection
- Other

The most often reported functions were "enhanced customer service," and "tamper detection." Figure 3-1 shows the results of the FERC Survey.

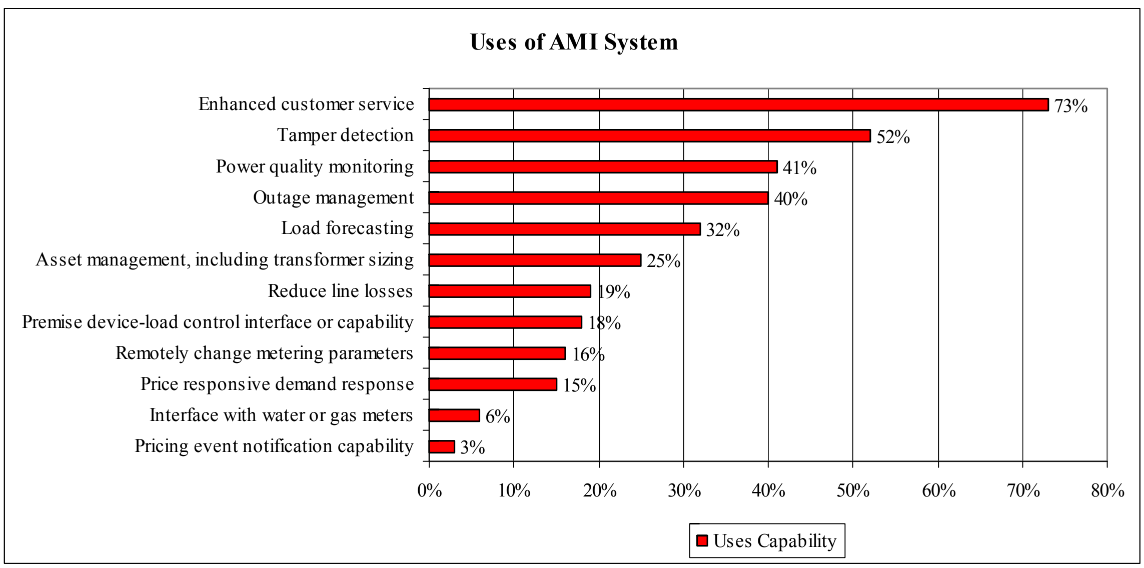

Figure 3-1
Uses of AMI System

Survey (FERC Survey) requested information on a) the number and uses of advanced metering and b) existing demand/response and time-based rate programs, including their current level of resource contribution.

[68] For purposes of this report, Commission staff defined "advanced metering" as follows: "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point."

The identification of these uses of advanced metering by utilities points to a number of areas related to the detection and reduction of non-technical losses. Recognition of these functions indicates the importance of non-technical losses to utilities as part of overall AMI programs. At minimum, it shows that AMI must deliver enhanced customer service and tamper detection:

> *Enhanced Customer Service:* The ability to offer ultimate customers the choice of bill data, additional rate options such as real time pricing or critical peak pricing, verification of an outage or restoration of service following an outage, more information to address a customer concern over an electric bill, reduced bill estimates when a meter read is not available, opening or closing of an account due to customer relocation without requiring a site visit to the meter(s), and/or more accurate bills.[69]
>
> *Tamper Detection:* The ability to detect the possibility that a revenue or billing meter has been tampered with, and to indicate a potential energy theft in progress, to be further investigated by the utility.

Theft at the Meter

There are two types of theft at the meter that contribute to non-technical losses: bypassing the meter and tampering with the meter itself.[70] The various ways in which this theft is done are listed in the following two inserts.

Installation Tampering

Line-side taps
- Weather-head
- Service entrance conductors
- Underground
- Switchgear / buswork / troughs

Bypass
- Jumpers in meter socket
- Close bypass device

Instrument transformer installations
- "Re-wiring"
- Shorting of current transformers

Meter Tampering

Internal to the meter
- Adjustment screws—one time
- Register tampering
- Magnetic circuit alteration
- Electrical alteration
- Dial tampering—Recurring

External to the meter
- Magnets—RC
- Hole in cover / disk "pinning"
- Upside-down meter
- Stolen meter

Internal physical tampering with the meter itself appears to be a less popular method of stealing energy than bypassing the meter or using diversionary taps installed ahead of the meter in the supply wiring.[71]

[69] AMI—through remote reading—allows for faster, more accurate accounts, reduces discrepancies, and through remote connect/disconnect allows for faster, more timely activation and deactivation of accounts. This translates to more revenue and fewer disputes.

[70] AMR Tamper Detection - The Good, the Bad, and the Possibilities, Ed Malemezian

Installation tampering and meter tampering should be kept in mind while considering the technology features described in this chapter.

Technologies

The uses of AMI technologies to support revenue assurance programs were discussed in the previous chapter. In this chapter, we shall focus on describing the technologies in terms of their characteristics and functionality.

Meter Features

Among the meter features used in AMI systems, those that are important for detecting non-technical losses are listed in the following insert.

[71] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC and Baltimore Gas & Electric Co., Baltimore, MD: 2001. 1000365.

Meter Standards and Features

Important for Detecting Non-technical Losses

Institute of Electrical and Electronics Engineers (IEEE)/ American National Standards Institute (ANSI) Standards

- IEEE 1701/ANSI C12.18 (1996)
  Protocol Specification for ANSI Type 2 Optical Port
- IEEE 1377/ANSI C12.19 (1997)
  Utility Industry End Device Data Tables
- IEEE 1702/ANSI C12.22 (1999)
  Protocol Specifications for Telephone Modem Communications

High-accuracy internal clock

Communications
- two-way communications
- communications functions that can be installed without disturbing metrology

Measurements
- power quality measurements: outage detection and duration; phase loss, sag, and surge detection
- storage capabilities for multiple sets of readings
- event log with circular memory buffer to store up to 100 events
- measure and display active energy delivered, received or net, or any two registers from delivered, received and net (kWh and kVAH)

Prepayment
- prepay functionality, including varying deductions per time-of-use scheduling, configurable emergency credit, and audible low-credit alarm

Security
- measurement technology that is immune to magnetic tampering
- record of programming changes, power outages, number of demand resets
- reverse disk rotation

Disconnect/connect
- disconnect switch controlled via software
- remote disconnect/reconnect switch

Tamper Detection
- tamper indications that can be communicated regularly through the communications system
- indicators include meter inversion, meter removal, and reverse energy flow
- tamper-resistance features that measure energy even if the meter is inverted and detecting when the meter is removed from a live socket
- increments a counter each time the meter senses reverse power flow
- power removal tamper (increments a counter each time the meter is removed from a live socket)

Hardware: Meter Requirements

Meter requirements will be discussed under four major headings:

1. Meter accuracy
2. Tamper detection
3. Remote testing and diagnostics
4. Remote disconnect / connect

Meter Accuracy

The accuracy of metering data is becoming increasingly important as advanced metering provides data that are integrated across many utility functions. The trend towards solid-state meters capable of delivering information for real-time use has increased both the visibility and importance of meter accuracy to distribution utilities, customers, and regulators. The increasing inaccuracy of legacy electromechanical meters as they age contributes to non-technical losses.

To evaluate the best metering platform for AMI, one utility performed a statistical study of electromechanical meter accuracy.[72] The results were as follows:

1. A thorough statistical analysis of electromechanical meter accuracy found that 20% of electromechanical meters have a high likelihood of under-recording usage by an average of nearly -0.8% (or 99.2% meter accuracy), with significant levels of variability in meter accuracy.
2. Service location (environmental factors), manufacturer meter serial number, and meter age were found to be reliable predictive factors of electromechanical meter accuracy.
3. The “accurate life” is about 25 years for most electromechanical residential meters and about 20 years for most electromechanical demand meters.
4. The volume of in-service meters recommended for replacement was highest for meters purchased from the late-1970s to the mid-1980s. Over 32,000 in-service meters recommended for replacement had an unknown purchase year and an average kWh composite meter error of -1.13%.

Meter Accuracy

Mechanical meters, in addition to being less accurate than solid-state electronic meters when new, fail as they age. Many meters eventually fail completely and register zero-use. Such failures often go undetected for a period of time because they are assumed to be caused by customer vacancy. Eliminating slow meters and other metering issues involving “lost and unaccounted for” energy use will result in accurate bills and assign payment obligations to those customers who use the energy rather than to all other customers.

Meter Reading and Customer Service Field Functions, Safety, Billing and Revenue Protection, Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design, SGD&E before the CPUC, March 28, 2006.

[72] *Metering Accuracy, Solid State Metering and the Electric Utility Enterprise Transformation*, Dave Mundorff, Entergy Corporation. September, 2005.

Tamper Detection

Tamper detection features that are important to AMI include the following:

- Reverse energy flag / reverse energy register
- Tilt switch
- Meter inversion
- Blink counter—no power to meter
- Magnetic sensors and diagnostics

These tamper detection features are described in the sections below.

Reverse Energy Flags
Reverse energy flags detect meters that have been turned upside down. In addition to the flag, some meters capture the reverse energy in a separate register. Other meters simply add reverse energy to forward energy, thereby accumulating total consumed. Theft is detected when the total no longer matches the meter dials.

Tilt Switches
Tilt switches detect meters that have been tilted from the normal position, usually around 50° to 70°. Tilt switches are prone to give false indications from vibrations. Meter removal is inferred when the tilt switch closes and a power outage detected after short time delay. Tilt switches, along with the outage detection, provide a reliable indication of meter removal. However, it must be noted that meter removal does not necessarily mean that tampering has taken place.

Meter Inversion
Meter inversion is inferred when meter removal has been detected.[73] In this instance, the tilt switch stays closed and power is restored, providing a reliable indication that the meter is running upside down. This also can generate a reverse energy flag.

Blink Counters
Blink counters measure increments for each interruption detected. A repeated number of interruptions can indicate tampering.

Magnetic Sensors & Diagnostics
Site and meter diagnostic sensors on solid-state meters (solid-state meters only; not meters with communication interface add-ons) detect meter wiring, instrument transformer, voltage, and current balance problems. Meter diagnostic flags detect internal meter malfunctions and tampering.

Reverse energy flags have proved effective in tamper detection. However, AMI generates a very large number of flags that must be sorted out. In many cases, the number of flags is overwhelming. Some of the flags are "false;" for example, magnet sensors generate many false flags.

[73] When the meter is pulled out of the socket and plugged back in upside down, the meter runs backwards and the kWh register goes down instead of up. The user leaves the meter inverted for a number of days to shave usage off the bill, and the meter is then reinstalled before a meter reading.

To be effective, tamper indicators must be filtered to spot trends and provide reliable comparisons.[74] Blink counts and outage flags must be compared against neighbors. Regular meter work, emergency work, maintenance, and repair work must be backed out of data on meter tilts, removals, and power outages. In other words, a system solution is required for these features to be utilized effectively by revenue protection departments.

Tamper Detection Features

Meters shall be able to:

- detect removal from its socket and generate a tamper event before it loses ability to communicate with the communications network
- detect voltage at the load side when the disconnect switch in the meter is open (for the purpose of detecting meter bypass) and generate a tamper event
- detect physical inversion and generate a tamper event
- detect physical tampering, such as, seal tampering, meter ring removal, case / cover removal, etc. and generate a tamper event
- transmit and locally log the following information (at a minimum) for each tamper event:
    1. Event Timestamp
    2. Tamper status (event type)
    3. Meter ID
- communicate tamper events to the Data Center Aggregator as soon as they occur (when possible)
- send meter tamper events with a higher priority than normal status messages
- store tamper events and transmit them when meter communications are re-established (if the meter is unable to communicate at the time the tamper event is detected)
- distinguish initial installation events and re-energize events (i.e. after an outage) from meter removal and reinstallation (potential tampering) to avoid transmission of non tamper related events.
- store tamper events until they are flagged for deletion once they have been successfully transferred to the Data Center Aggregator and 45 days have passed.

AMI Preliminary System Requirements, SCE. June 2006.

Testing and Diagnostics

Since AMI systems allow the reduction or elimination of meter service personnel and on-site visits, remote diagnostics are used to replace the meter reader's "eyes in the field."

Diagnostic features located in the meter typically provide measurements of parameters such as the following:

- Polarity
- Voltage deviation

[74] AMR Tamper Detection—The Good, the Bad, and the Possibilities, Ed Malemezian

- Inactive phase current
- Phase angle displacement
- Current imbalance
- Reverse energy

Service scan diagnostics read data on these parameters and current conditions at meter locations.

Results are reviewed by engineering staff who initiate an investigation, issue an instruction for meter change-out, or an investigation of the distribution line.

Service scans can discover open voltage test switches, current test switches left shorted, failed wiring on the meter harness from test switch to meter base or incorrect initial wiring, failed voltage transformers, and open distribution line fuses. All of these, including meter failure itself, contribute to non-technical losses.

The requirements for testing and diagnostics for meters and data center aggregators are shown in the following insert.

Testing and Diagnostics

Meter shall be able to:

- support a remotely or locally initiated meter test for communications connection status
- support a remotely or locally initiated meter test for energized status
- support a remotely or locally initiated meter test for load side voltage
- support a remotely or locally initiated meter test for disconnect switch status
- support a remotely or locally initiated meter test for internal clock time accuracy
- return results for all remote or local meter tests within 60 seconds
- Neighborhood Aggregator shall permit remote:
    1. status report (up / down)
    2. diagnostics
    3. link status report
    4. communications event log retrieval

Data Center Aggregator shall be able to:

- provide comprehensive remote testing and diagnostic capabilities for each system component (communications and meters) based on a (periodic) schedule or on demand. Remote testing and diagnostic alarm messages are to be considered high priority.
- remotely test meters for communications status, energized status, load side voltage and switch status on-demand.
- remotely test communications with external third parties.
- identify the probable cause of a communications failure within the AMI communications network.
- provide mechanisms for remotely correcting system/component problems, which at a minimum shall include the ability to remotely recycle (or restart) a component.
- log the results of all remote testing and diagnostics activities and any automatic actions taken based on those results.
- make the results of all received alerts and remote testing and diagnostic results available to authorized IT systems (e.g. MDMS, CSS, Work Order Tracking, etc.).
- have configurable alert levels and notifications based on the severity of a problem detected and the number of endpoints affected.
- classify specific testing/diagnostic results to either require or not require human intervention (configurable) in the determination of issuing trouble reports.
- detect if any network components are not responding within the following intervals based on the number of meters affected. (Estimate only; different network topologies will result in different values.)

    A) < 200 meters - next read.
    B) 200 - 1000 meters - within 6 hours
    C) 1000 - 5000 meters - within 1 hour
    D) 5k - 20k meters - within 15 minutes
    E) 20k - 50k meters - within 1 minute

AMI Preliminary System Requirements, SCE. June 2006.

Remote Disconnect / Connect

With solid-state meters being deployed as part of AMI systems over entire service territories, remote connect/disconnect features are attractive from service, operational, and economic points of view. The key driver for this change is that meter providers can integrate the disconnect/connect switch into the solid-state meter.

Remote connect/disconnect switches have traditionally been installed on electric meters for customers who either were consistently late on paying their electric bill or that lived in an area where people moved more frequently.[75] These classes of customers have a high incidence of non-technical losses with respect to non-payment of bills and errors in billing due to timing of disconnects / connects (stop time for one customer; start time for another).

[75] This is not an insignificant class of customer. For example, customers in SCE's service territory move at a rate of one in every four customers per year. (Paul DeMartini, Director AMI Program)

Remote Connect/Disconnect Features

Meter shall be able to:

- accept scheduled service disconnect/ reconnect
- remotely disconnect/ reconnect on demand
- remotely disconnect/reconnect according to utility pre-configured rules
- detect duplicate service disconnect/ reconnect events and ignore the duplicate events (e.g. Meter is already on -- reconnect event accepted with no action taken)
- cancel or update/reschedule scheduled disconnect/ reconnect events prior to their completion
- send a meter read and acknowledgement to Data Center Aggregator upon a successfully completed or failed electric service disconnect/ reconnect event
- enable an SCE Employee working on-site at the customer premise to be able to physically operate its service disconnect/ reconnect switch at any time. 24 hours, 7 days a week, 365 days a year
- support an external authorization/ authentication routine (i.e. by remote systems or field tool) to enable only active and eligible SCE employees to operate its service disconnect/reconnect switch on-site at the customer premise
- allow authorized SCE employee (while on-site at the customer premise) to operate the service disconnect/reconnect switch immediately (regardless of interval) or to schedule a connect/ disconnect for a future interval
- log date/time and status of attempts to operate the service disconnect/reconnect switch remotely or on-site at the customer premise. Log entries will include requesting user or system identity and authorization status
- remotely disconnected/reconnected on demand and have acknowledgement received by requesting system within 1 minute of request being initiated
- allow a reconnect event to occur following a disconnect event only after a configurable amount of time (e.g. at least 1 to 2 minutes) has elapsed since the disconnect event.
- Note: Should a disconnect event and reconnect event be scheduled to occur for the same meter on the same day, Meter shall log the events and automatically provide an on-demand read to the Data Center Aggregator without operating the disconnect/reconnect switch

AMI Preliminary System Requirements, SCE. June 2006.

Software-based Applications and Tools

To be effective, AMI tamper indicators need to be filtered to spot trends, outliers, and provide for reliable comparisons. Blink counts and outage flags need to be compared against neighbors. Normal meter and trouble work need to be backed out of meter tilts, removals, and power outages. Custom algorithms and a formal process are required to look at trends. Energy consumption needs to be compared—by individuals and by groups.

To be most effective, AMI data needs to be combined with the following:

- Class of customer
- Geographical information
- Normalization for weather, occupancy, and other similar factors
- Customer's past history—family, friends, and other businesses
- Other utility usage—gas, water, cable
- Experience

Software-based applications and tools must be used to analyze the data that are delivered by AMI metering and communications technology to utilities—revenue assurance departments in particular. There are three major categories of software-based applications and tools that are necessary for AMI to effectively detect and reduce non-technical losses and maximize its impact on revenue:

1. Meter data management systems
2. Statistical analysis
3. GIS—at time of installation and for identifying locations for abnormal behavior

Meter Data Management Systems

Advanced metering delivers frequent interval data, which greatly increases the amount of information a utility will have about consumption. The volume, frequency, resolution, and type of data (for example, interval demand data, voltage, outage events, and meter tempering indications) delivered by AMI from meters are vastly different from manual meter reads and mobile (drive-by) meter-reading systems.

MDMS is used to manage the large volumes of meter data generated from AMI systems. MDMS is the software that accepts data collected from an AMR/AMI system, stores the data, and forwards the data to utility systems such as billing. MDMS is an essential tool for utilities that may have tens or even hundreds of thousands or millions of meters generating data that are gathered in multiple ways.

Data Collection and Analysis

While AMI monitors customer power consumption , MDMS uses the data collected for statistical analyses that generate standard reports, such as Hi/Lo reads with statistical process control charts, multi-day bad meter reads, zero usage day with non-zero average, and custom meter groups. These can be used to identify customer load changes that may be related to meter theft.

MDMS is used to develop actionable intelligence for use in revenue protection programs. MDMS receives revenue protection flags from the meters and compares them with usage trends, outage information, and service order/field work to determine which are actual revenue protection issues and which are false positives.

By relying on a central repository of historic meter data, analytics can pinpoint usage patterns that might indicate meter defect, meter tampering, or theft of service. If a customer's energy usage remains abnormally low during heat waves, cold snaps, or before and after outages, then the meter might be malfunctioning. If more energy is flowing past distribution points than is being billed for, then it's possible that someone is stealing service. Without meter data management, this type of revenue-assuring analysis is nearly impossible.

MDMS is used to validate data against theft indicators, automatically initiating appropriate alerts and tracking responses. MDMS is used to set threshold levels for usage on a premise-by-premise basis.

Integration with CIS and Billing Systems

MDMS automates and streamlines the identification of accounts with potential theft, thus reducing the time and expense of unnecessary site visits by revenue investigators. With visibility into the probable condition of each meter in the system, revenue investigators can monitor accounts systemwide without additional investments in time, resources, meter seals, locks, and other security gadgets.

For optimum performance of AMI-supported applications such as tamper or leak detection and processing of on-demand and off-cycle reads, MDMS should be integrated with utility functions carried out in CIS, billing, and other systems such as load control. Customer service personnel, for example, should have access to daily and interval read information provided by AMI to respond to billing inquiries, process service cancellations, and perform other functions. This will require development of new screens for integrating and displaying data and can be time-consuming to develop and test.

Interestingly, MDMS identifies meter failure before the billing cycle, thus avoiding billing errors on both the hardware and software components of AMI, both contributors to non-technical losses.

Integration into AMI and Enterprise

To realize the benefits of revenue protection, including meter tempering and illegitimate consumption, AMI must be capable of providing the data required to detect theft. This means that MDMS should be able to ingest and analyze the AMI data to initiate, track, and close-out follow-up work orders via the utility's work order management system with respect to meter installations, change-outs, communications interfaces, maintenance, and upgrades.

MDMS is an integral and essential part of AMI with respect to developing solutions for non-technical losses.

MDMS and the AMI Technology Evaluations

Conceptually, the meter module hardware, communications infrastructure, AMI head-end system, the MDMS, and the integrations with a utility's existing back-office systems should be thought of as one end-to-end integrated and seamless solution that, only together, can enable the utility to achieve the expected benefits of AMI. Hence, it is beneficial for a utility to assess the capabilities it requires of an MDMS and determine how the AMI data will touch the utility's existing systems, the same time when evaluating AMI technologies and developing an AMI business case.

Meter Data Management System, Tram, Hahn and Ash, Chris, Enspiria Solutions. August 29, 2005.

Statistical Analysis

AMI generates a wealth of data. The shear volume of this data demands that software applications be developed to perform statistical analysis for it to be useful for detecting and correcting non-technical losses. As meters become more sophisticated (solid-state meters flag many meter-tampering techniques automatically in real time), so do thieves. Software applications can be used to strike the balance in favor of revenue assurance.

Some of the more prevalent software applications and techniques for statistical analysis are described in the sections below.

Customer Profiling

Load profiles and data mining techniques can be used to minimize non-technical loss activities. Load-profiling methods and data-mining techniques can be used to classify, detect, and predict non-technical losses in the distribution sector due to faulty metering and billing errors. They provide a framework for the analysis of customer behavior.

Load Profiling

The key to this approach is the recognition of significant deviations known as outliers in the customer behavior patterns. The method of doing so involves modules including the load profiling and non-technical losses analysis in processing large volumes of data relating to customers' electricity consumption patterns. The load profiling module includes clustering customer behavior according to the loading conditions identified and allocating the clustered load profiles to the respective categories based on the customer and commercial indices. The non-technical loss analysis module uses the representative load profiles as a time series model and detects the outliers based on the set up benchmark based on abnormal and normal behavior patterns. The detected abnormalities due to non-technical loss activities are used as a reference to develop a forecast model on non-technical loss profiles with other external features.

Framework Analysis of Customer Behaviour due to Non-Technical Losses in Malaysian Electricity Supply Industry, Anisah Hanim Nizar, ITEE. July 17, 2006.

Interval Metering

Since AMI systems can support frequent readings and high data resolution, interval metering is possible. This allows the utility to study consumption patterns for anomalies that may indicate metering problems.[76]

Some “smart meters” measure consumption in intervals of an hour or less. The resulting increase in data points (from 4 or 12 per year to 8700+) allows utilities to develop highly sophisticated customer profiles. This information can be used to analyze consumption patterns at sites where theft is suspected.

Utilities can develop and compare profiles within the billing system. However, the process would likely slow down bill production. A far more efficient solution lies in the use of an out-of-the-box business intelligence application that extracts data from a billing or meter data management application, then builds and compares profiles in a non-production environment.[77]

A list of significant deviations based on interval data provides targets for investigation. Deviation from a profile norm is a good indicator of theft, sufficient to merit investigation.

Distribution Analysis

Metering cannot detect bypass-tapping supply before it reaches the meter. For most utilities, bypass is the primary theft method. Bypass on underground lines can go undetected for years.[78]

Using data from smart meters, distribution management systems can be used to reach a solution to this problem. A distribution management system can correlate energy meter readings with available feeder load data to identify feeder loss characteristics and a profile. Utilities can use these to create a ranking of the worst performing distribution feeders. This system perspective of feeder loss allows a utility to address load theft where it is greatest. Also, smart-meter-provided power quality data (for example, voltage, current, and power factor) can assist in determining the feeder section losses.

This analysis helps narrow the source of a loss to a relatively small number of sites. Looking at the accounts associated with those sites, along with information on ownership and purported use, points to the likely location of the theft.

Trends and Comparisons

Custom algorithms and a formal process are required to identify trends. Energy consumption needs to be compared by individual customers and by class of customers. Comparisons are made by combining AMI data with the following:

[76] Load profile analysis using monthly meter readings is impractical for detecting energy theft. *Algorithm for Detecting Energy Diversion,* EPRI. 1991.

[77] New metering & grid applications improve theft detection, Adrian Patrick, PhD, Automatic Meter Reading Systems, Oracle, Utilities Global Business Unit. July 31, 2007.

[78] When the power is used for illegal, high-consumption “growing” and drug-manufacturing purposes, losses can be substantial.

- class of customer
- geographical information
- other utilities—cable, gas, water
- customer history and behavior patterns

Statistical Algorithms

MDMS uses a series of statistical algorithms that, in essence, perform the same initial screening and analysis work usually performed by a team of utility revenue assurance experts, only in a more consistent manner and at a much lower cost.

MDMS identifies revenue leakage by applying these algorithms, along with revenue assurance investigation best practices, across multiple utility internal data sources (CIS, MIS, WFMS) and appended with external data sources (SIC, zip +4, credit score, weather) to create a list of suspect accounts. The suspect list is a prioritized list of premises or accounts with reason codes and a weighted revenue recovery valuation of each opportunity. A suspect list is provided to the utility's revenue protection investigation team on a periodic basis for field investigation and subsequent actions (for example, customer contact, back-billing, mediation, and negotiations).

Geographical Information Systems (GIS)

GIS mapping and integration with customer databases is used to identify and locate consumers on the geographical maps being fed from the distribution network. There may be cases where an electric connection exists, but is not in the utility's record. There may be instances of unauthorized connections or unrecorded connections. On the other hand, there may be instances where a connection is recorded, but does not exist physically at the site.

GIS provides utilities with accurate data and useful information to manage their assets and customer base. GIS coupled with GPS can assist in maintaining data integrity and recovering "lost revenue."

GIS should be used to provide aerial photographs or maps of the area, with spatial references to the physical and electrical distribution network, metering points within buildings, and buildings without meters installed. All network and customer documentation should be linked, and all assets in the area should be mapped. Widespread access to relevant data should be available through a web-enabled client-server.

Installation of AMI at the substation level helps to target areas where technical and, more importantly, non-technical losses are problematic.

Results from analysis using GIS-enabled tools can be used to focus energy audits by revenue protection teams. In the case of major retail and industrial customers, technical specialists can prioritize locations for on-site audits, checking meters and installations, instrument transformers, metering and billing constants and ensuring that no by-passing is taking place.

GIS is an ideal integration platform for meter data, supervisory control and data acquisition (SCADA), and customer information systems, as shown in Figure 3-2.

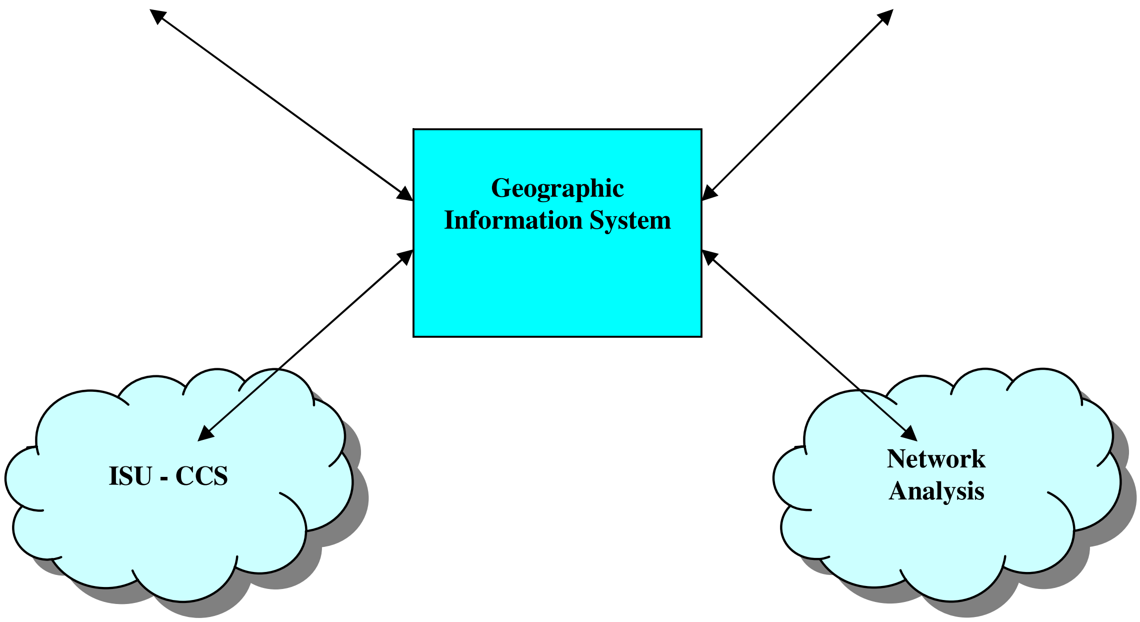

Figure 3-2
Geographic Information System

Tasks for which spatial data can improve processes are meter reading (including rollout of AMI systems), credit and collections, customer analytics, billing, and customer communications. An enterprise GIS fully integrated within the mainstream of utility IT infrastructures helps utilities understand customer behavior and their transactions.[79]

GIS can help visualize significant mismatches between known usage and actual consumption using GIS advanced network modeling.

Many utilities consider the GIS system as the "ultimate" source database, acting as a common repository for all enterprise applications. This is accomplished by integrating GIS technology into the mainstream business operations of the company.

[79] *GIS Enhances Electric Utility Customer Care*, An ESRI ® White Paper. May 2007.

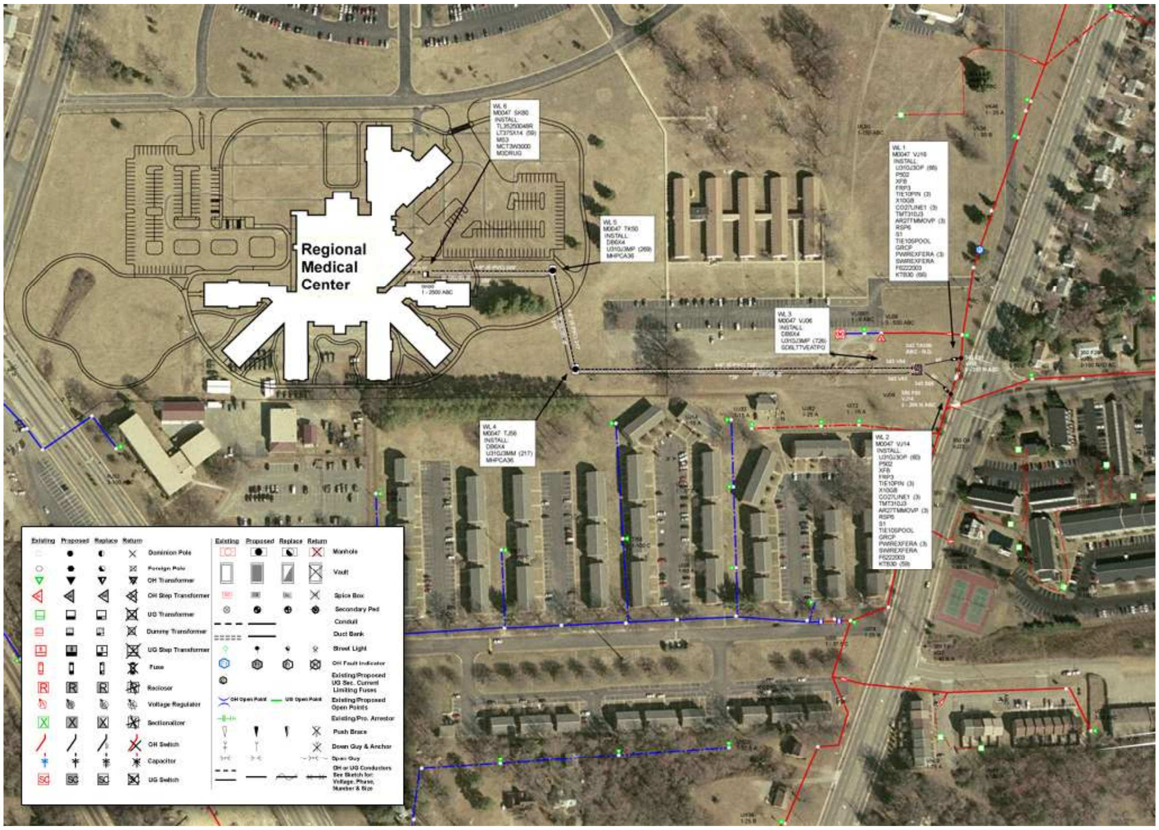

Figure 3-3
GIS Aerial Map

GIS Integration Functional Requirements

The functional requirements for integrating AMI with GIS are as follows: [80]

- Complete automation of the distribution network is not possible. It would require implementation of SCADA/DMS at every section of distribution system, which is prohibitively expensive. Hence, getting real-time data from SCADA/DMS for all parts of distribution network is not possible. This problem can be overcome by the integration of GIS with AMR/AMI.
- Normally, the metering data from AMR/AMI are available to billing personal. However, these data are not available to other employees directly. Once integrated with GIS, every employee can have access to data through multiple GIS applications.
- AMR/AMI data are helpful for detecting losses in the distribution system. Using GIS, losses can be viewed geographically and analyzed. This analysis can be used to map areas where there is a high incidence of theft or other distribution system losses. These maps can be used to develop predictive models (Figure 3-3).
- Energy consumption information can be used to build databases of real-time and historical (periodical) demand and energy data at the source (for example, feeders and

[80] A detailed discussion of this subject can be found in *GIS integration with SCADA, DMS & AMR in Electrical Utility*, Uday D. Kale and Rajesh Lad. Reliance Energy Ltd., Map India. 2006.

DTs) and load (consumers) levels. This information can be used to build network simulations of loading conditions and for load forecasting. These databases can be helpful in developing profiles, behavior models and incidence indicators for theft.

- With the data received from AMR/AMI, GIS tools can be used for energy auditing in a geographic context, which is useful in specifically identifying particular areas suffering high energy losses.
- The correct assessment of technical and non-technical loss components needs correct metering data. This information can be provided over the GIS platform. GIS tools can be used by network analysts to identify and display spatially feeders, transformers, and distribution areas having high-energy losses (Figure 3-4).

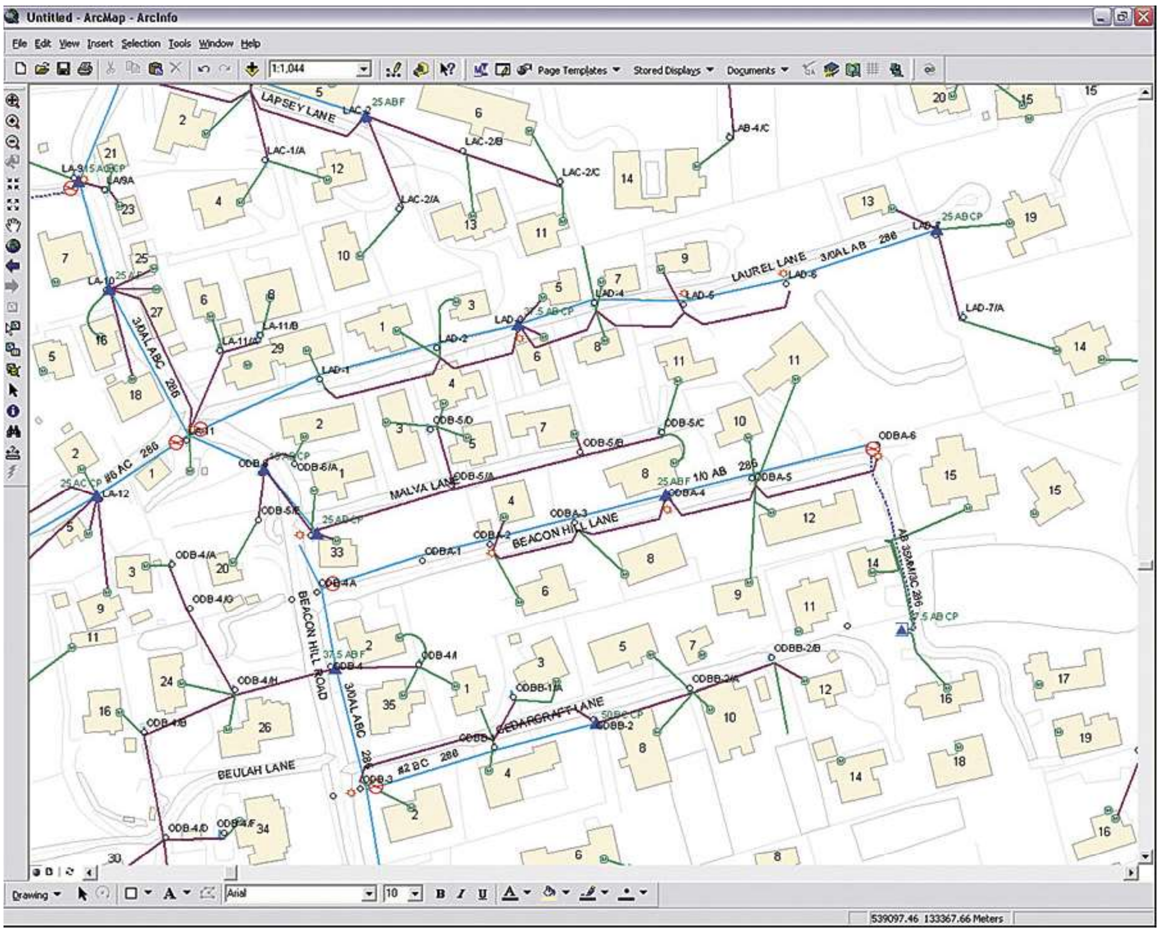

Figure 3-4
GIS High-Energy Loss Map

GIS and Field Inspections

GIS mapping of AMR/AMI data has been used successfully to identify locations for field inspections. These have led to high "hit rates" for the detection of meter tampering. An example of GIS for field inspections is shown in Figure 3-5.[81]

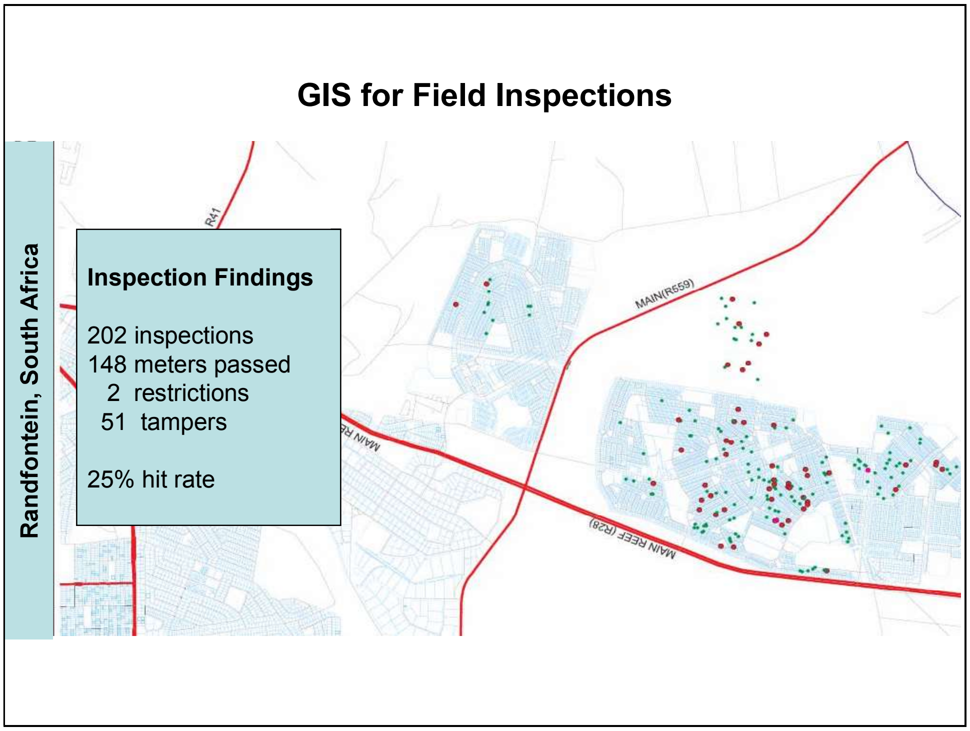

Figure 3-5
GIS for Field Inspections

Analyzing Theft at Substation Level

With integrated GIS, it is possible to access exactly the geographical areas where theft is most prevalent, areas where theft can be preempted by enhanced levels of vigilance, and areas where revenue assurance should step up its efforts and be more accountable for results. Typically, the area served by a substation is only a few square kilometers in size, facilitating the implementation of corrective measures.

GIS can play a major role in identifying areas of the distribution network where theft is likely. Identifying potential theft in the distribution network is accomplished by the integration of billing and SCADA systems on a GIS platform.[82]

[81] *Resource & Revenue Protection as a Tool for DSM*, Christophe Viarnaud, Actaris and Gregor Schmitz, BreakThru Consulting.

[82] *Role of GIS in Preventing Power Pilferage,* Dr. Nagesh Rajopadhyay, Manish Arora and P. Madhusudhan, Info Tech Enterprise Limited, Hyderabad. GIS Based Distribution System Planning, Analysis and Asset Management Training Program, USAID.

SCADA systems continuously collect real-time readings of all electrical parameters at monitored points on feeders.[83] The system obtains information on the status of various switching devices (for example, circuit breakers, switches and isolators) and transformer parameters (for example, tap position).

When electronic meters are installed at the customer level, they can be equipped with an interface for communications with the SCADA system, using an industry standard protocol. Meter readings can then be used both to monitor the load and to detect attempts to tamper with the meter. As soon as a tamper is detected, the meter/consumer can be tagged on the GIS system. The information can then be passed on to revenue assurance for physical checks and corrective action.

PSS/Engines™ must be interfaced with GIS for network analysis and optimization. A data model must be created in GIS for geographic locations as well as for the network.

Steps for the system and database integration and GIS mapping:

- Interface of billing system to GIS (GIS application software reads external relational database management system [RDBMS] of billing system).
- Entry of billing-related information to customer database.
- Identify the total power delivered from the substation (P-total) and the total power billed to the customer (P-billed).
- Calculate network power loss (P-lost) with network analysis tools and map network data in GIS.
- Calculate power theft (P-theft) or commercial loss at the substation level. Formula: (P-theft) = (P-total) - (P-billed) - (P-lost).
- Plot the results on GIS.

A similar analysis can be made at the transformer level, provided that the meter is installed at the transformer and a reading is available.

A link must be maintained between the external billing database and the GIS database. Billing data must be populated simultaneously in the external database and the GIS database. After the entry of meter data at a substation level, the system can be asked to evaluate the total commercial loss.

[83] These parameters include voltage, angle, power factor, active power, reactive power, and energy.

Implementation of AMI Technology

The way in which an AMI installation is planned and executed has a major impact on its success in ensuring that the technologies are installed properly, detecting meter tampering and by-pass at the time of installation and setting up and integrating the data management systems and GIS platform for revenue assurance programs in the future. It must be recognized that installation of hardware and software is as important as the technologies themselves for realizing the benefits that AMI offers for the detection and control of non-technical losses.

Successful implementation of AMI technology requires the participation of experienced revenue assurance staff at all stages of the process—planning, procurement, installation, and integration into the utility enterprise systems. These individuals have valuable insights into the transition from manual to remote meter reading and auditing. They have much on-site experience to share for meter replacement. Moreover, they understand the need for comprehensive data management tools. Most importantly, revenue assurance offers quality control for the realization of the operational savings that provide the economic justification for many AMI programs.

4
CHAPTER 4

Overview PPL Electric Utilities

PPL Electric Utilities is the regulated electricity and gas subsidiary of PPL Corporation. The annual revenues and assets of PPL Corporation are $6.9 billion and $19.7 billion, respectively. PPL Electric Utilities serves over 1.4 million customers over 10,000 square miles in Central Eastern Pennsylvania (Figure 4-1).

PPL Electric Utilities has a peak load of ~7,700 MW with 36.7 billion kWh delivery.

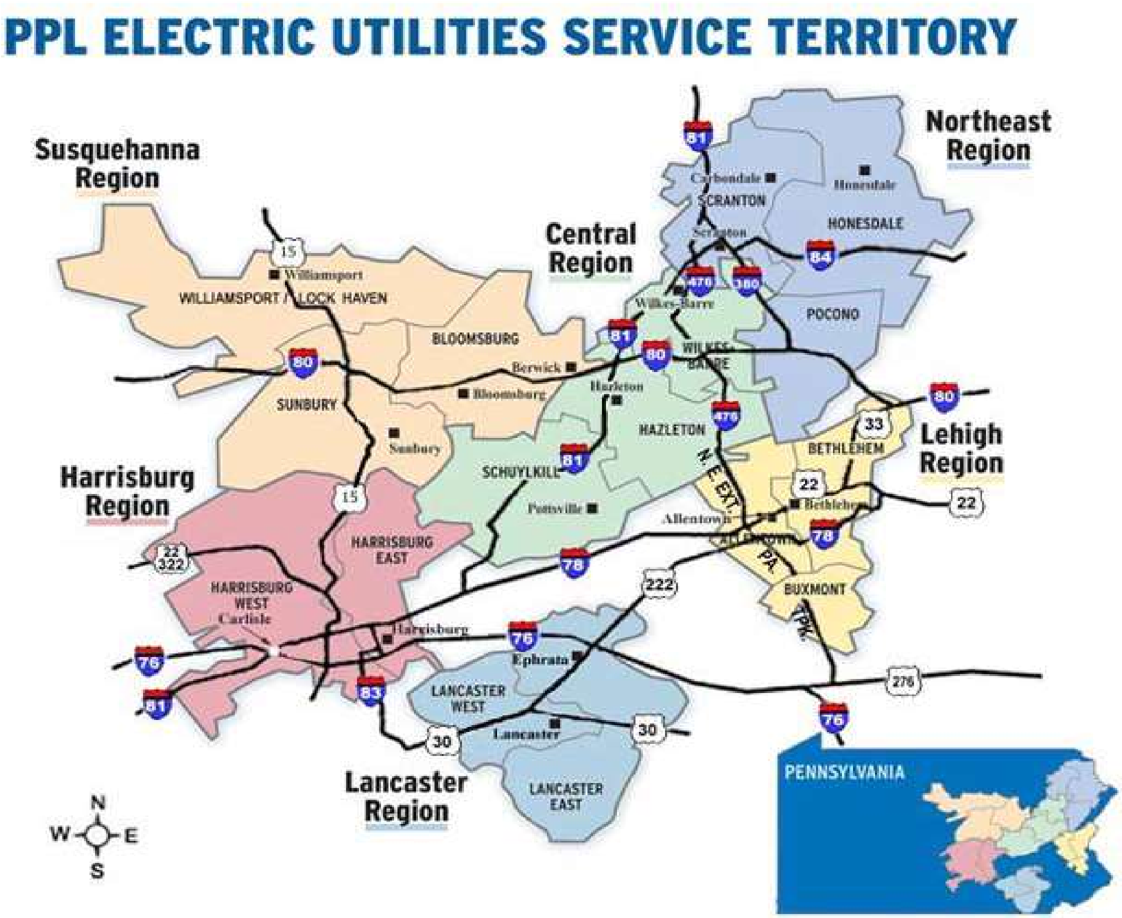

Figure 4-1
PPL Electric Utilities Service Territory

PPL Electric Utilities was one of the first utilities to introduce an automated meter-reading system, starting the program in November 1999 and completing the deployment to its 1.4 million customers in October 2004. Beginning in the spring of 2002 and concluding in the fall of 2004, PPL deployed an automated meter-reading system that included the replacement of over 1.4 million meters, installation of communications equipment in over 330 substations, and modified meter data and billing systems. Total implementation cost was $163 million. The automated meter-reading system replaced 175 manual meter readers and allowed the reduction of personnel for large power installations from 17 to 11.

With manual reads, PPL Electric Utilities experienced 95% accuracy (due to human error and weather, especially snow); accuracy with automated meter reading is now close to 99.8%.

PPL Electric Utilities started change management for business processes six months before installation. Before installation started, 200 business processes were reviewed; 70 risks were identified and addressed and appropriate changes made to ensure the successful transition to the automated meter-reading system. Many of these changes related to billing processes and impacted revenue assurance and, thus, non-technical losses.

The information technology staff was actively involved in the project team, contributing to the smooth transition. During the installation period, manual meter reads were sent to billing using middleware, so downstream processes did not notice the difference between manual and remote meter reads. The computer software programs and interfaces necessary to transfer the automated meter reads to the PPL billing system were developed in-house. Among these were the data validation and revenue assurance tools. Statistical analysis was used very early on. From the beginning of the project, the information technology staff, using its own software, provided effective and productive applications for revenue assurance.

Although the system deployed by PPL Electric Utilities was an automated meter-reading (AMR) system, it was designed as an advanced metering infrastructure (AMI) system upon which expanded capabilities could be deployed. These expanded capabilities include two-way communications and the use of a commercial MDM solution.

The AMI system reads meters three times per day; hourly data collected daily for each customer. The database currently (2008) holds over three terabytes (two years of data). This is the largest database of hourly data in the industry.

PPL Electric Utilities was one of the earliest utilities to deploy and utilize AMR/AMI throughout its entire service territory, establishing it as one of the leaders in the industry. As of 2006 it had the second largest deployment in the United States (1,353,024 meters), after PECO Energy (1,759,913); Wisconsin Energy was third (723,000), Wisconsin Public Service fourth (396,837), and United Illuminating fifth (324,992).

The transition from manual to remote meter reading at PPL Electric Utilities was well managed with an inclusive and highly competent project team, making it a model for the industry. Most importantly, with respect to the subject of this study, the AMR/AMI system at PPL Electric utilities provides new and innovative tools for revenue assurance that have a positive impact on the reduction on non-technical losses.

Revenue Assurance Using Meter Data from AMI with Meter Data Management Software

AMI fundamentally alters the way revenue assurance operations are performed. In the past, the Revenue Assurance group at PPL Electric Utilities used various strategies to identify specific target accounts for investigation. Most of these strategies involved manual analysis of large quantities of data, a labor-intensive exercise. The data available for such queries were generally limited to daily and monthly consumption. The results were based on an *ad hoc* process that takes considerable time, with different screening tests being designed and deployed at different times. AMI, with a robust MDM system, changes this paradigm in several ways.

The collection of higher-frequency data and meter status by AMI—reverse rotation flags, outage count indicators, interval data, and metered usage on previously cut meters—is just the beginning of the assurance solution. MDM software helps utilities analyze AMI data, providing knowledge about customer energy use. In-depth analysis helps pinpoint where and by whom power is being diverted, making it easier to identify cases of theft. For example, such analysis enables the utility to discover when there is energy use on non-paying accounts and when there is no use for specific time periods on an active account.

Data Repository

The core repository of data is collected from multiple sources: AMI meters, weather, customer and billing, SCADA, GIS mapping and real-time pricing, as shown in Figure 4-2. The data are validated and stored in two scenarios, working and approved.

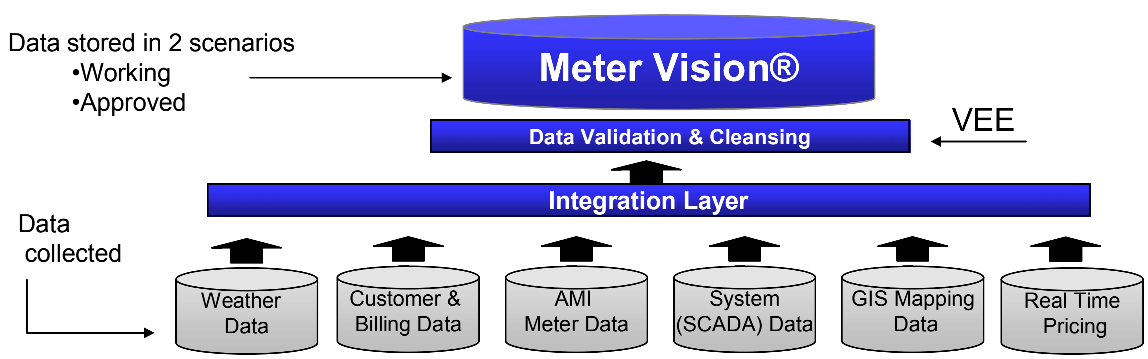

Figure 4-2
Data Repository

Data Repository and Applications

Revenue assurance software allows PPL Electric Utilities to zero in on problem accounts by combining data collected by the AMI system, such as daily readings, interval data, and momentary interruption notifications (blink counts) with other pertinent information such as daily temperatures, meter status, and account status.

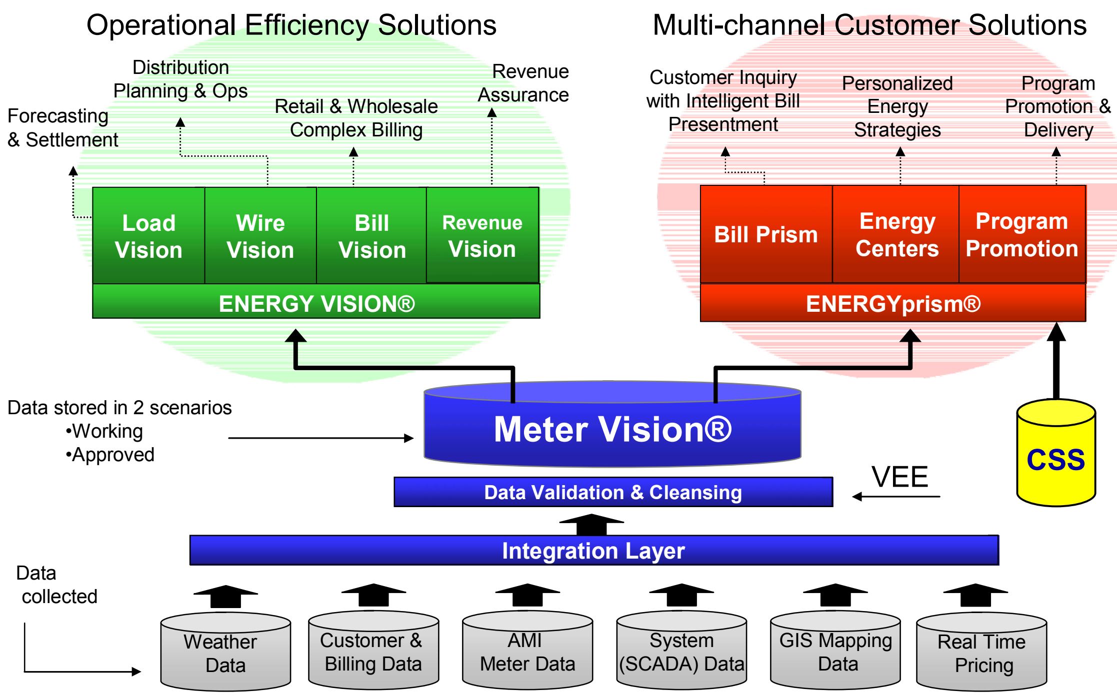

Figure 4-3
Data Repository and Applications

The combination of data and applications for analysis together constitute the Revenue Vision solution at PPL Electric Utilities (Figure 4-3).

Revenue Vision

The Revenue Assurance group at PPL Electric Utilities uses MDM software, called Revenue Vision, to help them simplify the process for identifying possible cases of theft, meter tampering, or equipment problems. This takes a significant amount of guesswork out of the effort to identify possible theft cases. Rather than make assumptions about the cause of a reduction in consumption, the granularity of data available from MDM can provide a pattern that can be used to identify theft or failing equipment with a high degree of confidence so that the site visit to confirm will be fruitful. It also allows users to create rules and logic, manage the list of outputs, tweak logic for better results, and group the results by geographic location to make it easier to assign work to field investigators. An optimum solution would automatically notify group members of anomalies around usage patterns.

PPL Electric Utilities uses a commercial MDM solution to improve analyses of large volumes of interval, daily, and meter data collected by its AMI system. By combining various meter, premise, and account data, the software makes it easier to identify problem meters. PPL Electric Utilities identifies suspicious consumption patterns by applying specific, utility-defined screening tests to a targeted population of accounts, meters, or other entities. The goal is to define tests narrowly enough so that the data combination yields a true and manageably sized “hot list” of accounts requiring investigation.

Revenue Assurance Application

- The revenue assurance application is used today to find meter issues as well as theft.
- The application collects raw data from meters with a specific scenario.
- For example, meters with 3 hours of no use are collected between the hours of 6 pm and 6 am and reports them to a "hot list" for further investigation.
- Additionally, it collects meters that have reverse rotation with blinks and puts them on a "hot list" for additional investigation.

Tests

The Revenue Assurance group began its project by evaluating existing tests already in use for assessing monthly meter readings. During the course of the review, they were able to determine the biggest revenue loss issues, such as equipment malfunctions, installation issues, and potential theft, and to identify usage patterns that were indicative of each problem, as well as the customer class or attribute that should be tested. Upon completion of this exercise, the group came up with eight logic tests to implement within the MDM application and then determined the criteria for each; for example, the meter type or the account type as well as selecting a schedule for running the test (weekly, monthly, or quarterly).

Design and implementation of screening tests within MDM are distinctly separate steps. Analyses are designed to fit customer load and data characteristics to effectively identify energy theft or tampering. Once an analysis is designed, it is implemented as a regular production process, making it possible to keep up with the examination of current data and alert the Revenue Assurance group of anomalies as soon as they arise.

The design step involves exploratory analysis of different test schemes by running, reviewing, and comparing different result sets. Hourly data are utilized for these tests and supplemented by external data sources such as weather data, GIS, and customer characteristic data. In the design phase, these tests are run on all or just a sample of customers, with the primary purpose of evaluating the effectiveness of the tests, rather than simply generating customer lists from the tests.

Tests

- Periodic zero use/with blink—shows meter blinks and zero usage
- Periodic zero use/no blink—same above with no blinks
- Reverse rotation/with blink—shows reverse meter rotation
- Reverse rotation/no blink—same as above with no blink

Note: Typically, abnormal blink counts and reverse rotations counts are due to meter tampering.

PPL continues to refine other tests that will allow them to monitor accounts within two days of an event (for example, termination for non-payment or slowing or stopped meter).

The implementation step is automated. Once logic tests are found to be effective by the analyst, they are put into production by scheduling them as automated runs for whatever period makes sense. All AMI data are initially screened by the validation rules inherent in the MDM system.

After validation, certain accounts are identified for further review. The revenue assurance analyses are run automatically on selected meters. Tests can be nested into a single logic string within a single production run, rather than performed sequentially in multiple runs.

Analysts apply standard tests or test combinations to specific accounts or groups of accounts. Failure of a combination of tests may detect meter tampering. For example, the combination of a loss of power indicator on a meter with a reverse rotation flag is a better indicator of theft than either test alone. No one test determines energy theft or meter tampering, but various combinations of failures may place an account or meter on the suspicious account list.

Workflows

The next step in implementing the logic tests required that a workflow be set up for each of the tests (Table 4-1). The workflows consist of a name, brief description, the group of entities to be included in the test, and the filters necessary to identify the attributes of the entities included. Once the workflows were completed, the group determined how often to run the test.

PPL Electric Utilities generally runs tests weekly, but has the flexibility to change the frequency of test runs. Weekly runs allow better management of output, and there is an added security benefit from a frequent "electronic eye" on every meter in the field.

Table 4-1
Revenue assurance workflows at PPL Electric Utilities

Revenue Assurance Workflows at PPL Electric Utilities	
Workflow	**Description**
800 Series Commercial	Captures commercial meters that have 20% or greater decrease in monthly consumption and/or peak demand in comparison with lowest monthly consumption and peak demand of previous 12 months
800 Series Residential	Captures residential meters that have 20% or greater decrease in monthly consumption in comparison with lowest monthly consumption of previous 12 months
Seasonal Use	Captures seasonal meters that have 20% or greater decrease in seasonal consumption and/or peak demand in comparison with seasonal consumption and peak demand 1 year and 2 years ago
Billing Constant	Captures meters for which billing constant changed from that of previous month
CIM Monthly Commercial	Captures commercial meters that have registered 1000 kWh of consumption since account became inactive
CIM Monthly Residential	Captures residential meters that have registered 1000 kWh of consumption since account became inactive
CIM Weekly Commercial	Captures commercial meters that register average daily consumption of 500 kWh or greater since account became inactive
Load Factor Commercial	Captures commercial meters that have monthly load factor of 1 or greater
Load Factor Residential	Captures residential meters that have monthly load factor of 1 or greater
Periodic Zero Use Commercial	Captures commercial meters that register four or more consecutive hours of true zero use during calendar month (excl. power outages)
Periodic Zero Use Residential	Captures residential meters that register more than 40 occurrences of consecutive 12 hours of zero use during calendar month (excl. power outages)
Reverse Rotation and Blink	Captures meters that register reverse rotation and blinks, indicating meters potentially tampered with
Reverse Rotation and No Blink	Captures meters that register reverse rotation but no blinks, indicating defective meters creeping backwards
Reverse Spike Commercial	Captures commercial meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Reverse Spike Residential	Captures residential meters that have more than 6 occurrences of 90% or greater decrease in daily consumption from previous day during calendar month
Zero Use Commercial	Captures commercial meters that register zero consumption for calendar month
Zero Use Residential	Captures residential meters that register zero consumption for calendar month
Company Use	Captures meters classified as Company Use so they can be verified as such
Commercial Rate and Residential Revenue Class	Captures meters that have commercial rate class and residential revenue class
Residential Rate and Commercial Revenue Class	Captures meters that have residential rate class and commercial revenue class

Figure 4-4 shows a workflow that is used to find commercial meters that have 20% or greater decrease in the monthly consumption and or peak demand in comparison with the lowest monthly consumption and peak demand of the previous twelve months.

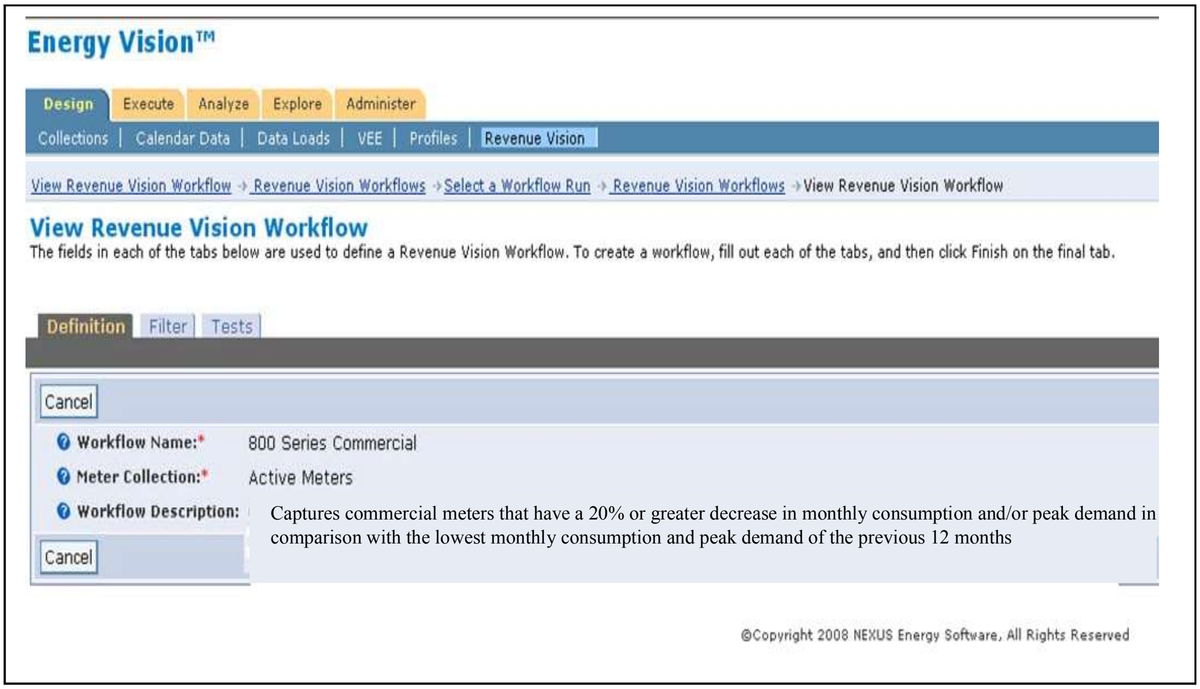

Figure 4-4
800 Series Commercial Workflow (Screen Print)

Filter

Within Revenue Vision (see Figure 4-5 Data Repository and Applications) a filter is applied by selecting the specific attributes, as well as a specific value such as commercial vs. residential—active vs. inactive—and so on.

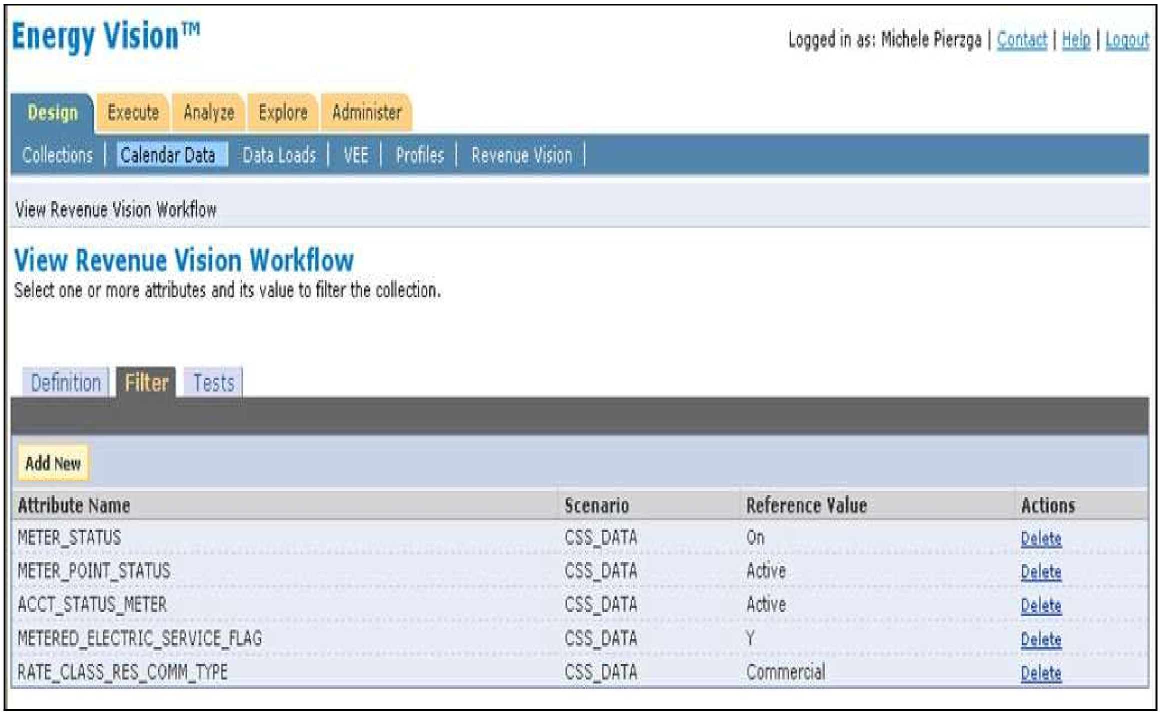

Figure 4-5
Filter (Screen Print)

"Hot List"

The results are displayed on a "hot list" (Figure 4-6) from which a Revenue Assurance specialist can pinpoint candidates for further investigation and corroboration of the AMI indicators.

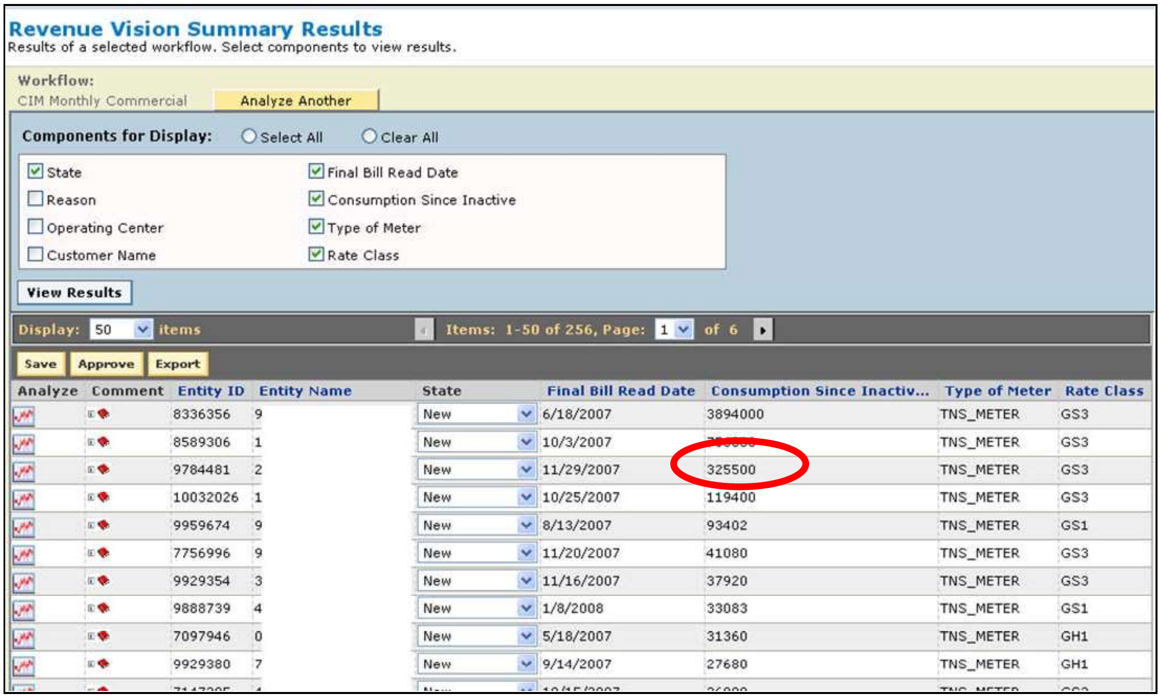

Figure 4-6
Hot list (Screen Print)

The "hot list" is used to prioritize revenue assurance leads for field personnel, thus reducing service order costs and efficiently identifying likely sources of non-technical losses.

Example of Theft Detection Using a Usage Pattern

In one recent case, PPL Electric Utilities was able to identify potential theft by looking at a usage pattern (Figure 4-7).

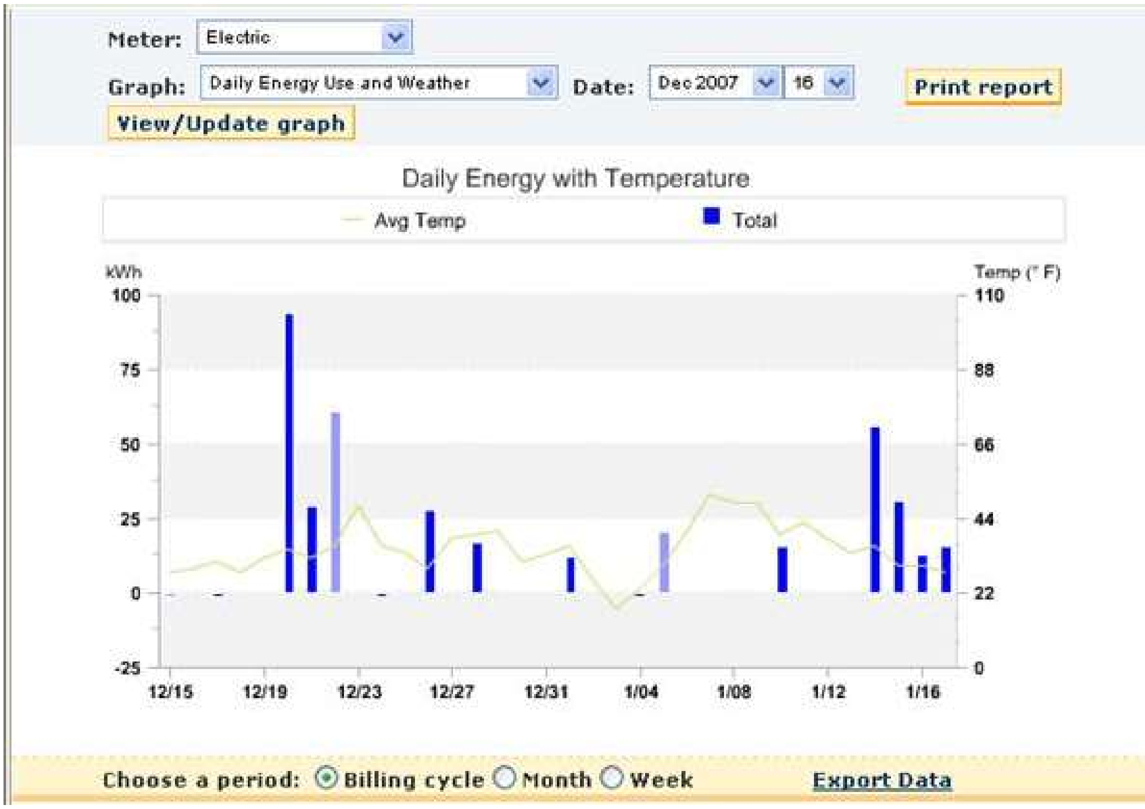

Figure 4-7
Usage pattern indicating abnormal meter behavior

The graph, taken from reports output from the MDM, indicates a suspicious usage pattern, with the meter going into a reverse rotation several times during a single billing cycle. What is more, there are days during the month when the customer is not using any power, while on other days the meter recorded usage. On December 20, 94 kW of usage was recorded, for example, while on January 3, when the temperature was -8°C, no usage was recorded. An investigation of the premises based on analysis of the AMI data indicated that the customer had tampered with the meter. Wires were attached to the meter's potential clip (Figure 4-8).

Figure 4-8
Meter recorded in Figure 7 with wires attached to its potential clip

The bypass was controlled by a simple toggle switch (Figure 4-9).

Figure 4-9
Toggle switch controlling the meter bypass

In this case, PPL Electric Utilities was able to use the interval data to extrapolate usage for rebilling purposes from the periods that were recorded.

Further, PPL Electric Utilities can use the detailed data for responding to questions raised by the judicial system.

Results

PPL Electric Utilities has had positive results from implementation of MDM-based revenue assurance software. The results for April and May 2008 are shown in the insert below.

RESULTS
April and May 2008

- Forty (40) cases were identified for a field investigation where 100% resulted in action being taken.
- Eighteen (18) of the cases were a result of equipment issues.
- In twenty (20) of the cases, theft was detected.
- Two of the cases revealed customer-owned generation via windmill and solar panel; these cases were identified through anomalies in blink counts and reverse rotation on the meters.

Reduction of Non-Technical Losses Using Meter Data Management

As defined in Chapter One, non-technical loss comprises distribution system losses caused by factors at the point of delivery and measurement. These losses are associated with unidentified and uncollected revenue, arising from pilferage, tampering with meters, defective meters, and errors in meter reading and in estimating un-metered supply of energy. System miscalculation on the part of utilities, due to accounting errors, poor record keeping, or other information errors also contribute to non-technical losses. In this example, the focus has been primarily on issues related to theft. However, in the future, PPL Electric Utilities expects to further maximize the benefits that can be derived from its meter data, such as using the features of its MDM system in customer service to respond more quickly and accurately to high-bill inquiries.

AMI at PPL Electric Utilities is an evolving enterprise. The ongoing initiatives of the AMI operations team will lead to further reductions in non-technical losses, as well as further benefits in terms of operational efficiencies and customer service.

Sources

AMI and MDM Program—PPL Electric Utilities, Mike Godorov, Manager; AMI Operations, Kimberly Golden, Supervisor—Information Solutions; and Wayne Fairchild, Special Project Manager, AMI, interviews and presentation. September 18, 2008.

PPL Electric Utilities Reduces Revenue Losses with AMI, Bernie Molchany, Manager—Revenue Assurance, PPL Electric Utilities; Michele Pierzga, Lead Business Systems Analyst, PPL Services Corporation; and Jackie Lemmerhirt, Director of Product Management, MDM, Aclara, Metering International. Issue 3 2008.

Using Meter Data from AMI with Meter Data Management Software to Identify Theft and Equipment Issues, Michele A. Pierzga, Lead Business Systems Analyst, PPL Services Corporation, Autovation 2008, Atlanta, GA. September 7, 2008.

A
APPENDIX

Product Differentiators

- Each product has its own distinct functional strengths and weakness.
- Each product has its own unique architecture differentiators, such as the ability to perform and scale as needed.
- Each product is implemented with differing technologies that the utility IT department has to support and integrate with other applications in the enterprise.
- Some products have service-based architectures at the enterprise level; others do not.
- Some products have well-defined interfaces and points of interoperability; others do not.
- Some products meet industry and international standards; others do not.
- Some products adhere to Smart Grid principles;[84] others do not.
- In addition, each vendor is unique in its level of product development maturity and implementation experience and expertise.

Utilities are encouraged to find the solutions that best fit their needs—in the present and foreseeable future.

[84] As envisioned by Smart Grid researchers such as EPRI, the California Energy Commission's Public Interest Energy Research program, the Modern Grid Initiative, and DOE's GridWise program.

Vendor List

Aclara Software
- Energy Vision®
- http://www.aclaratech.com/software/

Advanced AMR Technologies, LLC
- 8800 Energy Information and Control System
- http://www.advancedamr.com/

American Innovations Ltd.
- AIMetering System®
- http://www.aimonitoring.com

BPL Global
- Power SG™ Theft Detection
- http://www.bplglobal.net/

Detectent, Inc.
- Revenue Enhancement Suite
- http://www.detectent.com/

E-Mon LLC
- E-Mon Energy™
- http://www.emon.com

Echelon Corporation
- Networked Energy Services
- http://www.echelon.com

Ecologic Analytics, LLC
- WACS Meter Data Management System
- http://www.ecologicanalytics.com/

EKA Systems, Inc
- Energy Insight
- http://www.ekasystems.com

Elster Electricity, LLC
- EnergyAxis® System
- http://www.elsterelectricity.com

eMeter Corporation
- eMeter's Consulting and Implementation Services
- http://www.emeter.com/

EnergyICT Inc.
- COMServerJ
- http://www.energyict.com

Enerwise Global Technologies, Inc
- Metering & Integration
- http://www.enerwise.com

Envision Utility Software Corporation
- foCIS™
- http://www.envworld.com

IBM Corporation
- Asset Monitoring and Advanced Metering
- http://www.ibm.com/us/

InStep Software, LLC
- Enterprise Energy Management Software
- http://www.instepsoftware.com

Itron
- Enterprise Edition Customer Care
- http://www.itron.com

MeterSmart
- Meter Data Management
- http://www.metersmart.com

Metretek Inc.
- DC2000
- http://www.metretekfl.com/

MU Net, Inc.
- WebGate® System
- http://www.munet.com

Neptune Technology Group Inc.
- FIELDNET®
- http://www.neptunetg.com

Oracle
- Oracle Utilities Meter Data Management
- http://www.oracle.com/industries/utilities

OZZ Corporation
- Meter Data Management Solutions
- http://www.ozzcorp.com

Powel, Inc.
- Meter Data Management
- http://www.powel.com/

Power Measurement
- EEM Systems
- http://www.pwrm.com/

SAP America, Inc.
- SAP Enterprise Data Management
- http://www.sap.com/usa/industries/utilities/index.epx

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LG&E AND KU SERVICES COMPANY

LG&E Power System
2010 Analysis of System Losses

August 2012

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August 16, 2012

Mr. Robert M. Conroy
Director of Rates
LG&E and KU Services Company
220 West Main Street
Louisville, KY 40202

RE: 2010 LOSS ANALYSIS – LG&E

Dear Mr. Conroy:

Transmitted herewith are the results of the 2010 Analysis of System Losses for LG&E and KU Services Company's Louisville Gas & Electric (LG&E) power system. Our analysis develops cumulative expansion factors (loss factors) for both demand (peak/kW) and energy (average/kWh) losses by discrete voltage levels applicable to metered sales data. Our analysis considers only technical losses in arriving at our final recommendations. Please note that the proposed loss factors include a common or system-wide transmission factor for both LG&E and KU studies.

On behalf of MAC, we appreciate the opportunity to assist you in performing the loss analysis contained herein. The level of detailed load research and sales data by voltage level, coupled with a summary of power flow data and power system model, forms the foundation for determining reasonable and representative power losses on the LG&E system. Our review of these data and calculated loss results support the proposed loss factors as presented herein for your use in various cost of service, rate studies, and demand analyses.

Should you require any additional information, please let us know at your earliest convenience.

Sincerely,

Paul M. Normand
Principal

Enclosure
PMN/rjp

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

TABLE OF CONTENTS

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

1.0 EXECUTIVE SUMMARY

This report presents LG&E 2010 Analysis of System Losses for the power systems as performed by Management Applications Consulting, Inc. (MAC). The study developed separate demand (kW) and energy (kWh) loss factors for each voltage level of service in the power system for LG&E. The cumulative loss factor results by voltage level, as presented herein, can be used to adjust metered kW and kWh sales data for losses in performing cost of service studies, determining voltage discounts, and other analyses which may require a loss adjustment.

The procedures used in the overall loss study were similar to prior studies and emphasized the use of "in house" resources where possible. To this end, extensive use was made of the Company's peak hour power flow data and transformer plant investments in the model. In addition, measured and estimated load data provided a means of calculating reasonable estimates of losses by using a "top-down" and "bottom-up" procedure. In the "top-down" approach, losses from the high voltage system, through and including distribution substations, were calculated along with power flow data, conductor and transformer loss estimates, and metered poles.

At this point in the analysis, system loads and losses at the input into the distribution substation system are known with reasonable accuracy. However, it is the remaining loads and losses on the distribution substations, primary system, secondary circuits, and services which are generally difficult to estimate. Estimated and actual Company load data provided the starting point for performing a “bottom-up” approach for calculating the remaining distribution losses. Basically, this “bottom-up” approach develops line loadings by first determining loads and losses at each level beginning at a customer’s meter service entrance and then going through secondary lines, line transformers, primary lines, and finally distribution substation. These distribution system loads and associated losses are then compared to the initial calculated input into Distribution Substation loadings for reasonableness prior to finalizing the loss factors. An overview of the loss study is shown on Figure 1 on page 4.

Appendix A of this report presents the Transmission loss analysis which was calculated separately and the results incorporated into the final loss factors as shown on Table 1 on the next page.

Table 1 (columns (a) and (b)) also provides the final results from Appendix B for the 2010 calendar year. Exhibits 8 and 9 of Appendix B present a more detailed analysis of the final calculated summary results of losses by segments and delivery voltage of the power system. The following Table 1 cumulative loss expansion factors are applicable only to metered sales at the point of receipt for adjustment to the power system’s input level.

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

TABLE 1
Loss Factors at Sales (Meter) Level, Calendar Year 2010

Voltage Level of Service	Total LG&E	Delivery System (Excludes Transmission)	Recalculated Total LG&E With Appendix A Transmission Losses	
	(a)	(b)	(c)	(d) = 1/(c)
Demand (kW)				
Transmission[1]	1.01549	1.00000	1.02805	0.97272
Primary Substation	1.02152	1.00594	1.03415	0.96698
Primary	1.04295	1.02704	1.05585	0.94710
Secondary	1.06325	1.04703	1.07640	0.92902
Energy (kWh)				
Transmission[1]	1.01033	1.00000	1.02271	0.97779
Primary Substation	1.01619	1.00581	1.02865	0.97215
Primary	1.02998	1.01946	1.04261	0.95913
Secondary	1.05325	1.04160	1.06525	0.93875

Losses – Net System Input[2]	4.37% MWh
	5.56% MW
Losses – Net System Output[3]	4.57% MWh
	5.89% MW

Notes: *Column (a)* *Results derived from Appendix A for Transmission and Appendix B for all remaining factors.*

Column (b) *Column (a) loss factors excluding all Transmission-related losses.*

Column (c) *Column (b) delivery-only loss factors with incorporating the composite LGEE system-wide Transmission loss factors from Appendix A, Schedule 1, lines 5 and 10.*

Column (d) *All loss factors presented in columns (a), (b), and (c) are expansion factors applicable to metered sales as a multiplier. Column (d) is simply the inverse of column (c) and results in a loss factor that is used to divide metered sales to derive sales requirement at input.*

The loss factors presented in the Delivery Only column of Table 1 are the Total LG&E loss factors divided by the transmission loss factor from column (a) in order to remove these losses from each service level loss factor. For example, the secondary distribution demand loss factor of 1.04703 includes the recovery of all remaining non-transmission losses from the distribution substation, primary lines, line transformers, secondary conductors and services.

---

[1] Reflects results for 500 kV, 345 kV, 161 kV, 138 kV and 69 kV from Appendix A.
[2] Net system input equals firm sales plus losses, Company use less non-requirement sales and related losses. See Appendix A, Exhibit 1, for their calculations.
[3] Net system output uses losses divided by output or sales data as a reference.

The net system input shown in Table 1 represents the MWh losses of 4.37% for the total LG&E load using calculated losses divided by the associated input energy to the system. The 5.56% represents the MW losses also using system input as a reference. The net system output reference shown in Table 1 represents MWh losses of 4.57% and MW losses of 5.89%. These results use the appropriate total losses for each but are divided by system output or sales. These calculations are all based on the data and results shown on Exhibits 1, 7 and 9 of the study.

Due to the very nature of losses being primarily a function of equipment loadings, the loss factor derivations for any voltage level must consider both the load at that level plus the loads from lower voltages and their associated losses. As a result, cumulative losses on losses equates to additional load at higher levels along with future changes (+ or –) in loads throughout the power system. It is therefore important to recognize that losses are multiplicative in nature (future) and not additive (test year only) for all future years to ensure total recovery based on prospective fixed loss factors for each service voltage.

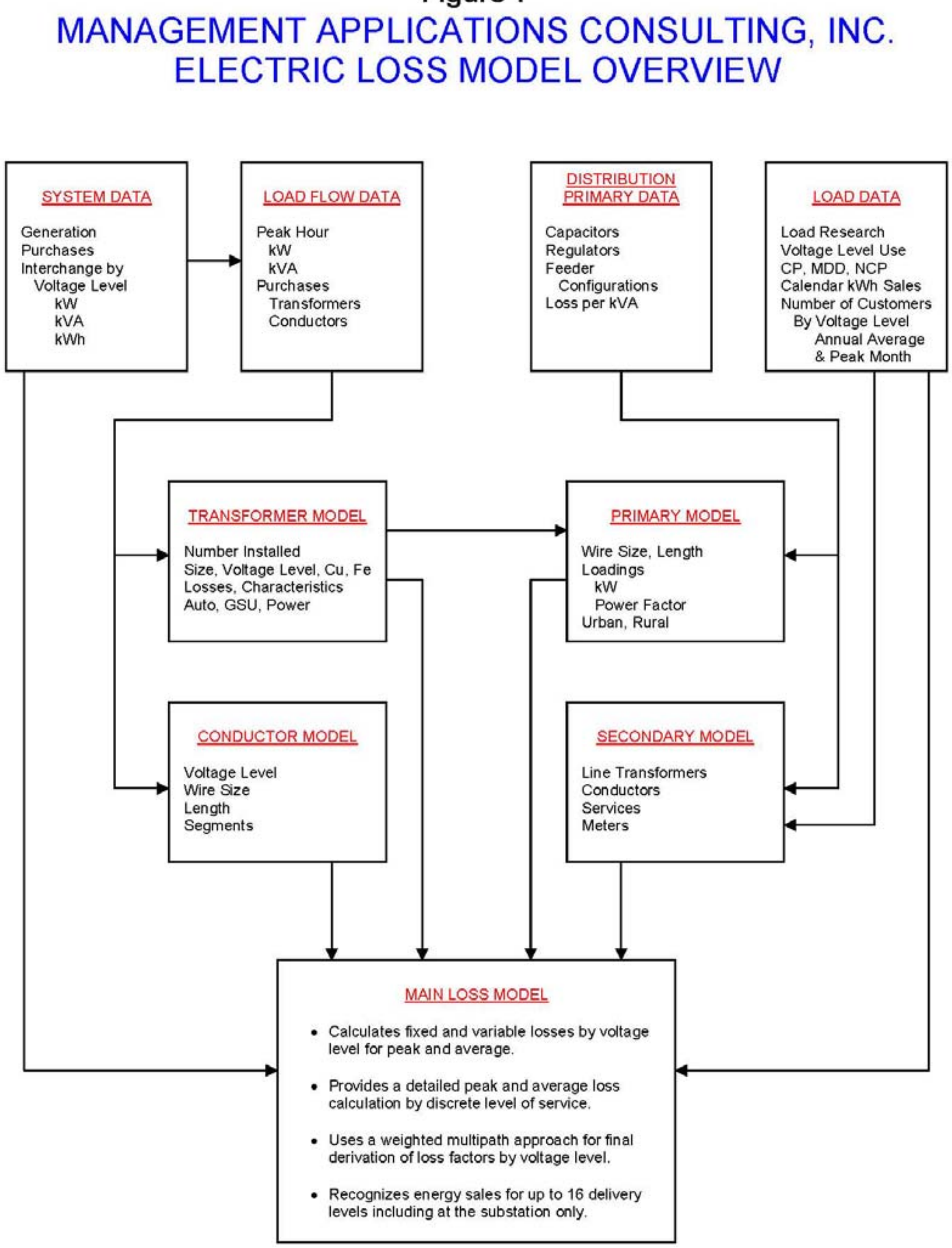
The derivation of the cumulative loss factors (Appendix B) shown in Table 1 (columns (a) and (b)) have been detailed for all electrical facilities in Exhibit 9, page 1 for demand and page 2 for energy. Beginning on line 1 of page 1 (demand) under the secondary column, metered sales are adjusted for service losses on lines 3 and 4. This new total load (with losses) becomes the load amount for the next higher facilities of secondary conductors and their loss calculations. This process is repeated for all the installed facilities until the secondary sales are at the input level (line 45). The final loss factor for all delivery voltages using this same process is shown on line 46 and Table 1 for demand. This procedure is repeated in Exhibit 9, page 2, for the energy loss factors.

The loss factor calculation is simply the input required (line 45) divided by the metered sales (line 2).

An overview of the loss study is shown on Figure 1 on the next page. Figure 2 simply illustrates the major components that must be considered in a loss analysis.

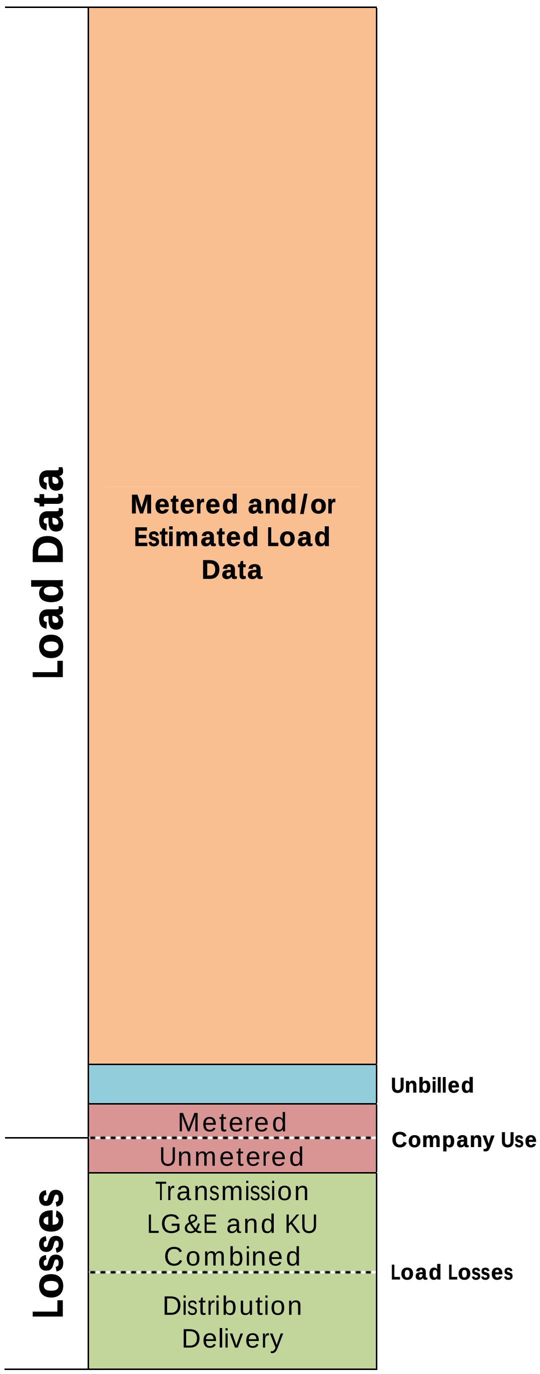
LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

Figure 1



LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

Figure 2
LG&E and KU Services Company – LG&E Jurisdiction Energy and Loss Components



2.0 INTRODUCTION

This report of the 2010 Analysis of System Losses for the LG&E power system provides a summary of results, conceptual background or methodology, description of the analyses, and input information related to the study.

2.1 Conduct of Study

Typically, between five to ten percent of the total kWh requirements of an electric utility is lost or unaccounted for in the delivery of power to customers. Investments must be made in facilities which support the total load which includes losses or unaccounted for load. Revenue requirements associated with load losses are an important concern to utilities and regulators in that customers must equitably share in all of these cost responsibilities. Loss expansion factors are the mechanism by which customers' metered demand and energy data are mathematically adjusted to the generation or input level (point of reference) when performing cost and revenue calculations.

An acceptable accounting of losses can be determined for any given time period using available engineering, system, and customer data along with empirical relationships. This loss analysis for the delivery of demand and energy utilizes such an approach. A microcomputer loss model[4] is utilized as the vehicle to organize the available data, develop the relationships, calculate the losses, and provide an efficient and timely avenue for future updates and sensitivity analyses. Our procedures and calculations are similar with prior loss studies, and they rely on numerous databases that include customer statistics and power system investments.

Company personnel performed most of the data gathering and data processing efforts and checked for reasonableness. MAC provided assistance as necessary to construct databases, transfer files, perform calculations, and check the reasonableness of results. A review of the preliminary results provided for additions to the database and modifications to certain initial assumptions based on available data. Efforts in determining the data required to perform the loss analysis centered on information which was available from existing studies or reports within the Company. From an overall perspective, our efforts concentrated on five major areas:

1. System information concerning peak demand and annual energy requirements by voltage level,
2. High voltage power system power flow data and associated loss calculations,
3. Distribution system primary and secondary loss calculations,
4. Derivation of fixed and variable losses by voltage level, and
5. Development of final cumulative expansion factors at each voltage for peak demand (kW) and annual energy (kWh) requirements at the point of delivery (meter).

[4]Copyright by Management Applications Consulting, Inc.

2.2 Electric Power Losses

Losses in power systems consist of primarily technical losses with a much smaller level of non-technical losses.

Technical Losses

Electrical losses result from the transmission of energy over various electrical equipment. The largest component of these losses is power dissipation as a result of varying loading conditions and are oftentimes called load losses which are proportional to the square of the current (I^2R). These losses can be as high as 75% of all technical losses. The remaining losses are called no-load and represent essentially fixed (constant) energy losses throughout the year. These no-load losses represent energy required by a power system to energize various electrical equipment regardless of their loading levels. The major portion of no-load losses consists of core or magnetizing energy related to installed transformers throughout the power system.

Non-Technical Losses

These are unaccounted for energy losses that are related to energy theft, metering, non-payment by customers, and accounting errors. Losses related to these areas are generally very small and can be extremely difficult and subjective to quantify. Our efforts generally do not develop any meaningful level as appropriate because we assume that improving technology and utility practices have minimized these amounts.

2.3 Description of Model

The loss model is a customized applications model, constructed using the Excel software program. Documentation consists primarily of the model equations at each cell location. A significant advantage of such a model is that the actual formulas and their corresponding computed values at each cell of the model are immediately available to the analyst.

A brief description of the three (3) major categories of effort for the preparation of each loss model is as follows:

- Main sheet which contains calculations for all primary and secondary losses, summaries of all conductor and transformer calculations from other sheets discussed below, output reports and supporting results.

- Transformer sheet which contains data input and loss calculations for each distribution substation. Separate iron and copper losses are calculated for each transformer by identified type.

Appendix A presents a separate hourly loss study result which derived the loss factors for the combined LGEE system-wide Transmission only (69 kV through 500 kV) of the LG&E and KU power system. These Transmission results are then incorporated on Table 1 of the Executive summary to derive the final LG&E 2010 loss factors by voltage level of energy delivery.

Appendix B presents a detailed loss study result which derives the loss factors for the Company's system-wide power system. Appendix B, Exhibits 8 and 9, presents the final detailed summary results of the demand and energy losses for each major portion of the total LG&E power system.

3.0 METHODOLOGY

3.1 Background

The objective of a Loss Study is to provide a reasonable set of energy (average) and demand (peak) loss expansion factors which account for system losses associated with the transmission and delivery of power to each voltage level over a designated period of time. The focus of this study is to identify the difference between total energy inputs and the associated sales with the difference being equitably allocated to all delivery levels. Several key elements are important in establishing the methodology for calculating and reporting the Company's losses. These elements are:

- Selection of voltage level of services,
- Recognition of losses associated with conductors, transformations, and other electrical equipment/components within voltage levels,
- Identification of customers and loads at various voltage levels of service,
- Review of generation or net power supply input at each level for the test period studied, and
- Analysis of kW and kWh sales by voltage levels within the test period.

The three major areas of data gathering and calculations in the loss analysis were as follows:

1. System Information (monthly and annual)

   - MWH generation and MWH sales.
   - Coincident peak estimates and net power supply input from all sources and voltage levels.
   - Customer load data estimates from available load research information, adjusted MWH sales, and number of customers in the customer groupings and voltage levels identified in the model.
   - System default values, such as power factor, loading factors, and load factors by voltage level.

2. High Voltage System (Appendix A)

- Conductor information was summarized from a database by the Company which reflects the transmission system by voltage level. Extensive use was made of the Company's power flow data with the losses calculated and incorporated into the final loss calculations.

- Transformer information was developed in a database to model transformation at each voltage level. Substation power, step-up, and auto transformers were individually identified along with any operating data related to loads and losses.

- Power flow data and calculations for each hour (8760) formed the basis for the peak and annual load losses in the high voltage (500 kV through 69 kV) loss calculations.

3. Distribution System (Appendix B)

- Distribution Substations – Data was developed for modeling each substation as to its size and loading. The Company provided loss characteristics for each transformer. Loss calculations were performed from this data to determine no load losses separately for each transformer. The annual load losses were calculated using an average load level for each transformer which replaced the prior Hoebel formula method.

- Primary lines – Line loading and loss characteristics for several representative primary circuits were obtained from the Company. These loss results developed kW loss per MW of load and a composite average percentage was calculated to derive the primary loss estimate.

- Line transformers – Losses in line transformers were based on each customer service group's size, as well as the number of customers per transformer. Accounting and load data provided the foundation with which to model the transformer loadings and to calculate load and no load losses.

- Secondary network – Typical secondary networks were estimated for conductor sizes, lengths, loadings, and customer penetration for residential and small general service customers.

- Services – Typical services were estimated for each secondary service class of customers identified in the study with respect to type, length, and loading.

The loss analysis was thus performed by constructing the model in segments and subsequently calculating the composite until the constraints of peak demand and energy were met:

- Information as to the physical characteristics and loading of each transformer and conductor segment was modeled.
- Conductors, transformers, and distribution were grouped by voltage level, and unadjusted losses were calculated.
- The loss factors calculated at each voltage level were determined by "compounding" the per-unit losses. Equivalent sales at the supply point were obtained by dividing sales at a specific level by the compounded loss factor to determine losses by voltage level.
- The resulting demand and energy loss expansion factors were then used to adjust all sales to the generation or input level in order to estimate the difference.
- Reconciliation of kW and kWh sales by voltage level using the reported system kW and kWh was accomplished by adjusting the initial loss factor estimates until the mismatch or difference was eliminated (Appendix B, Exhibits 6 and 7).

3.2 Calculations and Analysis

This section provides a discussion of the input data, assumptions, and calculations performed in the loss analysis. Specific appendices have been included in order to provide documentation of the input data utilized in the model.

3.2.1 Bulk and Transmission Lines (500 kV – 69 kV)

The transmission line losses were calculated based on a modeling of unique voltage levels identified by the Company's power flow data and configuration for the entire integrated Power System (Appendix A). Specific information as to length of line, type of conductor, voltage level, and hourly loading were utilized as data input in the power flow analyses.

Actual MW and MVA line loadings were based on LG&E's hourly loading conditions. Calculations of line losses were performed and summarized by fixed and variable components for both Transmission and GSU facilities for reporting purposes as shown in Appendix A of this report.

3.2.2 Bulk and Transmission Transformers

The transmission transformer loss analysis required several steps in order to properly consider the characteristics associated with various transformer types; such as, step-up, auto transformers, distribution substations, and line transformers. In addition, further efforts were required to identify both iron and copper losses within each of these transformer types in order to obtain reasonable peak (kW) and average annual energy (kWh) losses. While iron losses were considered essentially constant for each hour, recognition had to be made for the varying degree of copper losses due to hourly equipment loadings.

The remaining miscellaneous losses considered in the loss study consisted of several areas which do not lend themselves to any reasonable level of modeling for estimating their respective losses and were therefore lumped together into a single loss factor of 0.10%. The typical range of values for these losses is from 0.10% to 0.25%, and we have assumed the lower value to be conservative at this time. The losses associated with this loss factor include bus bars, unmetered station use, and grounding transformers.

3.2.3 Distribution System

The load data at the substation and customer level, coupled with primary and secondary network information, was sufficient to model the distribution system in adequate detail to calculate losses.

Distribution Substations

The Distribution Substation loss derivation required several steps to recognize the loss characteristics relating to iron or fixed losses versus the copper or load varying (I^2R) losses. The fixed component was based on Company loss characteristics from manufacturer's test results. The annual variable loss calculations considered a different approach by using an average hourly loading level and used this to the peak hour losses as a ratio $(\text{average/peak})^2$ times 8760 hours with an average adjustment factor and peak hour losses.

Primary Lines

Primary line loadings take into consideration the available distribution load along with the actual customer loads including losses. Primary line loss estimates were prepared by the Company for use in this loss study. These estimates considered loads per substation, voltage levels, loadings, total circuit miles, wire size, and single- to three-phase investment estimates. All of these factors were considered in calculating the actual demand (kW) and energy (kWh) for the primary system.

Line Transformers

Losses in line transformers were determined based on typical transformer sizes for each secondary customer service group and an estimated or calculated number of customers per transformer. Accounting records and estimates of load data provided the necessary database with which to model the loadings. These calculations also made it possible to determine separate copper and iron losses for distribution line transformers, based on a table of representative losses for various transformer sizes.

Secondary Line Circuits

A calculation of secondary line circuit losses was performed for loads served through these secondary line investments. Estimates of typical conductor sizes, lengths, loadings and customer class penetrations were made to obtain total circuit miles and losses for the secondary network. Customer loads which do not have secondary line requirements were also identified so that a reasonable estimate of losses and circuit miles of these investments could be made.

Service Drops and Meters

Service drops were estimated for each secondary customer reflecting conductor size, length and loadings to obtain demand losses. A separate calculation was also performed using customer maximum demands to obtain kWh losses. Meter loss estimates were also made for each customer and incorporated into the calculations of kW and kWh losses included in the Summary Results.

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit is provided in Appendices A and B:

Exhibit 1 – Summary of Company Data

This exhibit reflects system information used to determine percent losses and a detailed summary of kW and kWh losses by voltage level. The loss factors developed in Exhibit 7 are also summarized by voltage level.

Exhibit 2 – Summary of Conductor Information

A summary of MW and MWH load and no load losses for Distribution conductors by voltage levels is presented. The sum of all calculated losses by high voltage is based on input data information provided in Appendix A. Percent losses are based on equipment loadings.

Exhibit 3 – Summary of Transformer Information

This exhibit summarizes Distribution transformer losses by various types and voltage levels throughout the system. Load losses reflect the copper portion of transformer losses while iron losses reflect the no load or constant losses. MWH losses are estimated using an average load loss factor for copper and the annual load losses times the test year hours.

Exhibit 4 – Summary of Losses Diagram (2 Pages)

This loss diagram represents the inputs and output of power at system peak conditions. Page 1 details information from all points of the power system and what is provided to the distribution system for primary loads. This portion of the summary can be viewed as a "top down" summary into the distribution system.

Page 2 represents a summary of the development of primary line loads and distribution substa-tions based on a "bottom up" approach. Basically, loadings are developed from the customer meter through the Company's physical investments based on load research and other metered information by voltage level to arrive at MW and MVA requirements during peak load conditions by voltage levels.

Exhibit 5 – Summary of Sales and Calculated Losses

Summary of Calculated Losses represents a tabular summary of MW and MWH load and no load losses by discrete areas of delivery within each voltage level. Losses have been identified and are derived based on summaries obtained from Exhibits 2 and 3 and losses associated with meters, capacitors and regulators.

LG&E AND KU SERVICES COMPANY
2010 Analysis of System Losses – LG&E Power System

Exhibit 6 – Development of Loss Factors, Unadjusted

This exhibit calculates demand and energy losses and loss factors by specific voltage levels based on sales level requirements. The actual results reflect loads by level and summary totals of losses at that level, or up to that level, based on the results as shown in Exhibit 5. Finally, the estimated values at generation are developed and compared to actual generation to obtain any difference or mismatch.

Exhibit 7 – Development of Loss Factors, Adjusted

The adjusted loss factors are the results of adjusting Exhibit 6 for any difference. All differences between estimated and actual are prorated to each level based on the ratio of each level's total load plus losses to the system total. These new loss factors reflect an adjustment in losses due only to the kW and kWh mismatch.

Exhibit 8 – Adjusted Losses and Loss Factors by Facility

These calculations present an expanded summary detail of Exhibit 7 for each segment of the power system with respect to the flow of power and associated losses from the receipt of energy at the meter to the generation for the LG&E power system.

Exhibit 9 – Summary of Losses by Delivery Voltage

These calculations present a reformatted summary of losses presented in Exhibits 7 and 8 by power system delivery segment as calculated by voltage level of service based on reported metered sales.

Appendix A

Results of LGEE (LG&E and KU) Transmission System 2010 Loss Analysis

Louisville Gas and Electric Company (LGE)
Kentucky Utilities Company (KU)
2011 Transmission Loss Analysis

Pages 1-2 Index

Schedule 1, Page 3

Presents the summary loss results of the calculated hourly losses for the Company's LGE and KU control areas at the annual peak hour and for the annual average losses for all hours of the year.

Calculated loss factors are applicable to the metered (output) sales level.

All data is from Schedule 2.

Section I - Summarizes the transmission loss results with GSU losses included.

Section II - Summarizes GSU only losses.

Section III - Summarizes the transmission only losses exluding GSU losses.

Schedule 1A, Page 4

Presents the summary loss results of the calculated hourly losses for the Company's LGE control areas at the annual peak hour and for the annual average losses for all hours of the year.

Schedule 1B, Page 5

Presents the summary loss results of the calculated hourly losses for the Company's KU control areas at the annual peak hour and for the annual average losses for all hours of the year.

Schedule 2, Page 6

Summary of the summer and winter peak hour MW and annual MWH losses for LGE and KU and the total system.

Results are detailed by segment and season: Summer (June, July, August, and September), Winter (all months excluding Summer months).

Loss data is from Schedule 3.

Schedule 3, Page 7

Summary of MW and MWH loss results for each control area by season and voltage level.

Schedule 4, Page 8

Summary of seasonal peak hour MW and average MWH loss results for LGE by season and voltage level.

Louisville Gas and Electric Company (LGE)
Kentucky Utilities Company (KU)
2011 Transmission Loss Analysis

Appendices:

Appendices include summaries of hourly calculation of losses for each identified type at transmission voltage levels by season identified by fixed and variable with GSU losses identified separately.

Workpapers:

Workpapers 1 and 2 present detailed summary results of eight separate power flows for each control area (LGE and KU) for a total of sixteen unique simulations and loss results.

3 - Corona Loss Calculations

LGEE (LGE & KU) 2011 TRANSMISSION LOSS ANALYSIS (1)

	I TRANSMISSION LOSSES WITH GSU	LOSSES	% OF TOTAL TRANSMISSION	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
	A. DEMAND	Peak (MW) Summer (June - September)				
1	LGE	57.9	27.8%	4,060	4,002	1.01448
2	KU	150.3	72.2%	4,865	4,715	1.03187
3	Total Demand Losses Combined (3)	208.2	100.0%	7,905	7,697	1.02705
4	Unmetered Station Use Adjustment					0.00100
5	Demand Loss Factor					1.02805
	B. ENERGY	Annual MWH				
6	LGE	199,404	21.5%	21,626,727	21,427,323	1.00931
7	KU	727,568	78.5%	27,462,725	26,735,158	1.02721
8	Total Energy Losses Combined (3)	926,971	100.0%	43,634,621	42,707,650	1.02171
9	Unmetered Station Use Adjustment					0.00100
10	Energy Loss Factor					1.02271

	II TRANSMISSION GSU LOSSES	LOSSES (MW)			LOSSES (MWH)		
		FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
	A. GSU LOSSES (2)						
11	LGE	2.90	8.50	11.40	15,715	38,826	54,541
12	KU	2.40	5.40	7.80	14,820	25,784	40,604
13	Total GSU Losses	5.30	13.90	19.20	30,535	64,610	95,145

	III TRANSMISSION ONLY LOSSES	LOSSES	% OF TOTAL TRANSMISSION	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
	A. DEMAND LOSSES (Loss II-A)	Peak (MW) Summer (June - September)				
14	LGE	46.5	24.6%	4,049	4,002	1.01163
15	KU	142.5	75.4%	4,857	4,715	1.03021
16	Total Demand Combined (2)	189.0	100.0%	7,886	7,697	1.02456
17	Unmetered Station Use Adjustment					0.00100
18	Demand Loss Factor					1.02556
	B. ENERGY LOSSES (Loss II-A)	Annual MWH				
19	LGE	144,863	17.4%	21,572,186	21,427,323	1.00676
20	KU	686,964	82.6%	27,422,121	26,735,158	1.02570
21	Total Energy Combined (2)	831,826	100.0%	43,539,476	42,707,650	1.01948
22	Unmetered Station Use Adjustment					0.00100
23	Energy Loss Factor					1.02048

Notes:
(1) Study Period from February 2011 through January 2012.
(2) GSU losses from Schedule 3.
(3) See Schedule 1A, Schedule 1B, and Schedule 2.

LGE 2011 TRANSMISSION LOSS ANALYSIS

		LOSSES		INPUT	OUTPUT	LOSS FACTOR (Input/Output)
I	**TRANSMISSION LOSSES WITH GSU**					
	A. DEMAND	**Peak (MW) Summer (June - September)**				
1	LGE	57.9		4,060	4,002	1.01448
2	Unmetered Station Use Adjustment					0.00100
3	Demand Loss Factor					1.01548
	B. ENERGY	**Annual MWH**				
4	LGE	199,404		21,626,727	21,427,323	1.00931
5	Unmetered Station Use Adjustment					0.00100
6	Energy Loss Factor					1.01031

		LOSSES (MW)			LOSSES (MWH)		
II	**TRANSMISSION GSU LOSSES**	FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
	A. GSU LOSSES (1)						
7	LGE	2.90	8.50	11.40	15,715	38,826	54,541

		LOSSES		INPUT	OUTPUT	LOSS FACTOR (Input/Output)
III	**TRANSMISSION ONLY LOSSES**					
	A. DEMAND LOSSES	**Peak (MW) Summer (June - September)**				
8	LGE (Line 1 - Line 7)	46.5		4,049	4,002	1.01163
9	Unmetered Station Use Adjustment					0.00100
10	Demand Loss Factor					1.01263
	B. ENERGY LOSSES	**Annual MWH**				
11	LGE (Line 4 - Line 7)	144,863		21,572,186	21,427,323	1.00676
12	Unmetered Station Use Adjustment					0.00100
13	Energy Loss Factor					1.00776

Notes:
1. GSU losses from Schedule 3.
2. See Schedule 2

KU 2011 TRANSMISSION LOSS ANALYSIS

I TRANSMISSION LOSSES WITH GSU

		LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
	A. DEMAND	**Peak (MW) Summer (June - September)**			
1	KU	150.3	4,865	4,715	1.03187
2	Unmetered Station Use Adjustment				0.00100
3	Demand Loss Factor				1.03287
	B. ENERGY	**Annual MWH**			
4	KU	727,568	27,462,725	26,735,158	1.02721
5	Unmetered Station Use Adjustment				0.00100
6	Energy Loss Factor				1.02821

II TRANSMISSION GSU LOSSES

		LOSSES (MW)			LOSSES (MWH)		
		FIXED	VARIABLE	TOTAL	FIXED	VARIABLE	TOTAL
	A. GSU LOSSES (1)						
7	KU	2.40	5.40	7.80	14,820	25,784	40,604

III TRANSMISSION ONLY LOSSES

		LOSSES	INPUT	OUTPUT	LOSS FACTOR (Input/Output)
	A. DEMAND LOSSES	**Peak (MW) Summer (June - September)**			
8	KU (Line 1 - Line 7)	142.5	4,857	4,715	1.03021
9	Unmetered Station Use Adjustment				0.00100
10	Demand Loss Factor				1.03121
	B. ENERGY LOSSES	**Annual MWH**			
11	KU (Line 4 - Line 7)	686,964	27,422,121	26,735,158	1.02570
12	Unmetered Station Use Adjustment				0.00100
13	Energy Loss Factor				1.02670

Notes:
1. GSU losses from Schedule 3.
2. See Schedule 2

LGEE (LGE & KU) POWER FLOW RESULTS - SUMMARY OF LOSSES

TRANSMISSION LOSSES WITH GSU	PEAK (SUMMER) Total (MW)	PEAK (SUMMER) % of Total System Losses	PEAK (OTHER) Total (MW)	PEAK (OTHER) % of Total System Losses	ANNUAL Total Annual (MWH)	ANNUAL % of Total System Losses
LGE						
1 Transmission Use (Peak MW, Annual MWH)	4,002		3,300		21,427,323	
2 Input (Line 1 + Line 5)	4,060		3,328		21,626,727	
Transmission						
3 Fixed	5.9	2.9%	5.2	2.3%	43,657	4.7%
4 Variable	52.0	25.0%	22.5	10.0%	155,747	16.8%
5 Total Transmission - LGE	57.9	27.8%	27.7	12.3%	199,404	21.5%
6 Losses % of Input (Line 5/Line 2)	1.43%		0.83%		0.92%	
7 Losses % of Output (Line 5/Line 1)	1.45%		0.84%		0.93%	
KU						
8 Transmission Use (Peak MW, Annual MWH)	4,715		4,961		26,735,158	
9 Input (Line 8 + Line 12)	4,865		5,159		27,462,725	
Transmission						
10 Fixed	8.2	3.9%	8.1	3.6%	67,476	7.3%
11 Variable	142.0	68.2%	190.0	84.1%	660,091	71.2%
12 Total Transmission - KU	150.3	72.2%	198.1	87.7%	727,568	78.5%
13 Losses % of Input (Line 12/Line 9)	3.09%		3.84%		2.65%	
14 Losses % of Output (Line 2/Line 8)	3.19%		3.99%		2.72%	
TOTAL LGE & KU						
15 LGEE Load (Peak MW, Annual MWH) Input	8,925		8,487		49,089,452	
16 LGE Energy Delivery to KU	-1,020		-1,228		-5,454,831	
17 Total Load (Peak MW, Annual MWH)	7,905		7,259		43,634,621	
Transmission						
18 Fixed	14.2	6.8%	13.4	5.9%	111,133	12.0%
19 Variable	194.0	93.2%	212.5	94.1%	815,838	88.0%
20 Total System	208.2	100.0%	225.9	100.0%	926,971	100.0%
21 Losses % of Input (Line 20/Line 15)	2.33%		2.66%		1.89%	
22 Losses % of Output (Line 20/(Line 15/Line 20))	2.39%		2.73%		1.92%	

COMBINED LGEE DELIVERED ENERGY & LOSSES

	SUMMER		WINTER		ANNUAL	
23 LGEE Load (All data in MWH) Output	17,146,907		31,015,574		48,162,481	
24 LGE Energy Delivery to KU	-1,689,262		-3,765,569		-5,454,831	
25 Total Load (Annual MWH) Output	15,457,645		27,250,005		42,707,650	
Transmission Losses						
26 Fixed	37,940	11.1%	73,193	12.5%	111,133	12.0%
27 Variable	303,970	88.9%	511,869	87.5%	815,838	88.0%
28 Total Transmission Losses	341,909	100.0%	585,062	100.0%	926,971	100.0%
29 Losses % of Output (Line 28/Line 23)	1.99%		1.89%		1.92%	

LGEE (LGE & KU) POWER FLOW RESULTS - TOTAL TRANSMISSION

CONDUCTOR AND TRANSFORMER LOSSES (MW)

TIME	MW TRANSMISSION USE	Transmission Fixed	Transmission Variable	GSU Fixed	GSU Variable	Subtotal Conductor & Transformer	Load Adjustment for Combined Only
OTHER - LGE							
1 PEAK - MW	3,300	3.15	16.50	2.10	6.00	27.75	1228.00
2 LOSS % TO LOAD		0.095%	0.500%	0.064%	0.182%	0.841%	
3 LOSS % TO TOTAL LOSSES		11.349%	59.461%	7.568%	21.622%	100.000%	
4							
5 OTHER MWH	13,679,183	18,668	63,034	10,054	24,023	115,779	3,765,569
6 LOSS % TO LOAD		0.136%	0.461%	0.073%	0.176%	0.846%	
7 LOSS % TO TOTAL LOSSES		16.124%	54.443%	8.684%	20.749%	100.000%	
SUMMER - LGE							
8 PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95	1020.00
9 LOSS % TO LOAD		0.076%	1.087%	0.072%	0.212%	1.448%	
10 LOSS % TO TOTAL LOSSES		5.262%	75.066%	5.004%	14.668%	100.000%	
11							
12 SUMMER MWH	7,748,140	9,274	53,887	5,661	14,803	83,625	1,689,262
13 LOSS % TO LOAD		0.120%	0.695%	0.073%	0.191%	1.079%	
14 LOSS % TO TOTAL LOSSES		11.090%	64.439%	6.770%	17.702%	100.000%	
TOTAL ANNUAL - LGE							
15 SUMMER PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95	1020.00
16 ANNUAL MWH	21,427,323	27,942	116,921	15,715	38,826	199,404	5,454,831
17 LOSS % TO TOTAL ANNUAL OUTPUT		0.130%	0.546%	0.073%	0.181%	0.931%	
LOSS FACTORS - LGE							
18 Demand						1.01448	
19 Energy						1.00931	
OTHER - KU							
20 PEAK - MW	4,961	5.81	183.94	2.30	6.10	198.15	
21 LOSS % TO LOAD		0.117%	3.708%	0.046%	0.123%	3.994%	
22 LOSS % TO TOTAL		2.930%	92.831%	1.161%	3.079%	100.000%	
23							
24 OTHER MWH	17,336,391	35,105	408,661	9,366	16,151	469,283	
25 LOSS % TO LOAD		0.202%	2.357%	0.054%	0.093%	2.707%	
26 LOSS % TO TOTAL LOSSES		7.481%	87.082%	1.996%	3.442%	100.000%	
SUMMER - KU							
27 PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25	
28 LOSS % TO LOAD		0.123%	2.898%	0.051%	0.115%	3.187%	
29 LOSS % TO TOTAL		3.864%	90.945%	1.597%	3.594%	100.000%	
30							
31 SUMMER MWH	9,398,766	17,551	225,647	5,454	9,633	258,285	
32 LOSS % TO LOAD		0.187%	2.401%	0.058%	0.102%	2.748%	
TOTAL ANNUAL - KU							
33 PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25	
34 ANNUAL MWH	26,735,158	52,656	634,307	14,820	25,784	727,568	
35 LOSS % TO TOTAL ANNUAL OUTPUT		0.197%	2.373%	0.055%	0.096%	2.721%	
LOSS FACTORS - KU							
36 Demand						1.03187	
37 Energy						1.02721	
TOTAL ANNUAL - LGEE OUTPUT & LOSSES							
38 PEAK SUMMER - MW	8,717	8.86	180.15	5.30	13.90	208.20	1020.00
39 SUMMER MWH	17,146,907	26,825	279,534	11,115	24,436	341,909	1,689,262
40 PEAK OTHER MW	8,262	8.96	200.44	4.40	12.10	225.90	1228.00
41 OTHER MWH	31,015,574	53,773	471,695	19,420	40,174	585,062	3,765,569
42 ANNUAL MWH	48,162,481	80,598	751,228	30,535	64,610	926,971	5,454,831

LGE POWER FLOW RESULTS

CONDUCTOR AND TRANSFORMER LOSSES (MW)

	TIME	MW-LGE TRANSMISSION USE	Transmission Fixed (4)	Transmission Variable	GSU Fixed	GSU Variable	Subtotal Conductor & Transformer
	OTHER - LGE						
1	PEAK - MW	3,300	3.15	16.50	2.10	6.00	27.75
2	LOSS % TO LOAD		0.095%	0.500%	0.064%	0.182%	0.841%
3	LOSS % TO TOTAL LOSSES		11.349%	59.461%	7.568%	21.622%	100.000%
4							
5	OTHER MWH	13,679,183	18,668	63,034	10,054	24,023	115,779
6	LOSS % TO LOAD		0.136%	0.461%	0.073%	0.176%	0.846%
7	LOSS % TO TOTAL LOSSES		16.124%	54.443%	8.684%	20.749%	100.000%
	SUMMER - LGE						
8	PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95
9	LOSS % TO LOAD		0.076%	1.087%	0.072%	0.212%	1.448%
10	LOSS % TO TOTAL LOSSES		5.262%	75.066%	5.004%	14.668%	100.000%
11							
12	SUMMER MWH	7,748,140	9,274	53,887	5,661	14,803	83,625
13	LOSS % TO LOAD		0.120%	0.695%	0.073%	0.191%	1.079%
14	LOSS % TO TOTAL LOSSES		11.090%	64.439%	6.770%	17.702%	100.000%
	TOTAL ANNUAL - LGE						
15	SUMMER PEAK - MW	4,002	3.05	43.50	2.90	8.50	57.95
16	LOSS % TO SUMMER PEAK MW		0.076%	1.087%	0.072%	0.212%	1.448%
17	ANNUAL MWH	21,427,323	27,942	116,921	15,715	38,826	199,404
18	LOSS % TO ANNUAL MWH		0.130%	0.546%	0.073%	0.181%	0.931%
	LOSS FACTORS - LGE						
19	Demand						1.01448
20	Energy						1.00931

NOTES:
(1) Summer Period includes June, July, August, and September.
(2) Other Period includes all non Summer Period months.
(3) Transmission Use = Load + Exports + Passthroughs
(4) Transmission Fixed includes Corona Losses

KU POWER FLOW RESULTS

CONDUCTOR AND TRANSFORMER LOSSES (MW)

	TIME	MW-KU TRANSMISSION USE	Transmission Fixed (4)	Transmission Variable (5)	GSU Fixed	GSU Variable	Subtotal Conductor & Transformer
	OTHER - KU						
1	PEAK - MW	4,961	5.81	183.94	2.30	6.10	198.15
2	LOSS % TO LOAD		0.117%	3.708%	0.046%	0.123%	3.994%
3	LOSS % TO TOTAL LOSSES		2.930%	92.831%	1.161%	3.079%	100.000%
4							
5	OTHER MWH	17,336,391	35,105	408,661	9,366	16,151	469,283
6	LOSS % TO LOAD		0.202%	2.357%	0.054%	0.093%	2.707%
7	LOSS % TO TOTAL LOSSES		7.481%	87.082%	1.996%	3.442%	100.000%
	SUMMER - KU						
8	PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25
9	LOSS % TO LOAD		0.123%	2.898%	0.051%	0.115%	3.187%
10	LOSS % TO TOTAL LOSSES		3.864%	90.945%	1.597%	3.594%	100.000%
11							
12	SUMMER MWH	9,398,766	17,551	225,647	5,454	9,633	258,285
13	LOSS % TO LOAD		0.187%	2.401%	0.058%	0.102%	2.748%
14	LOSS % TO TOTAL LOSSES		6.795%	87.364%	2.112%	3.730%	100.000%
	TOTAL ANNUAL - KU						
15	SUMMER PEAK - MW	4,715	5.81	136.65	2.40	5.40	150.25
16	LOSS % TO SUMMER PEAK MW		0.123%	2.898%	0.051%	0.115%	3.187%
17	ANNUAL MWH	26,735,158	52,656	634,307	14,820	25,784	727,568
18	LOSS % TO ANNUAL MWH		0.197%	2.373%	0.055%	0.096%	2.721%
	LOSS FACTORS - KU						
19	Demand						1.03187
20	Energy						1.02721

NOTES:
(1) Summer Period includes June, July, August, and September.
(2) Other Period includes all non Summer Period months.
(3) Transmission Use = Load + Exports + Passthroughs
(4) Transmission Fixed includes Corona Losses
(5) Transmission Variable includes Losses at 0.5% from Appendix A (MW) and Appendix B (MWH)

	OTHER	SUMMER	OTHER	SUMMER
Kentucky Utilities	2/11/11 8:00	7/11/11 16:00		
	February-11	July-11		
Loads:				
1 KU Load (including losses)	4,292	4,102		
2 EKPC on KU	446	355		
3 TVA on KU	59	58		
4 OMU Load (3%)	-	12		
5 BREC on KU	6	6		
6 KMPA Load (3%)	108	129		
7 Total Load	4,911	4,662	4,911.00	4,662.00
Export (Delivered):				
8 KU Off-System Sales	-	-		
9 AMEM - Pass Through	-	-		
10 CARGILL - Pass Through	-	-		
11 OMU Exports	249	204		
12 KMPA Exports	-	-		
13 Constellation - Pass Through	-	-		
14 TEA - Pass Through	-	-		
15 TVA (OATT) - Pass Through	-	-		
16 Total Exports	249	204	249.00	204.00
17 BTM (0.5%) - OMU Network Load	112	182		
18 BTM (0.5%) - KMPA Gen	-	49		
19 Total BTM	112	231		
			5,160.00	4,866.00
20 Losses at 0.5%	0.560	1.155		
21 Losses from Schedule 5, Lines 1 and 8			-198.71	-151.41
22 Peak MW Load			4,961.29	4,714.59

Louisville Gas and Electric				
Loads:				
23 LGE Load (including losses)	1,725	2,654		
23 EKPC on LGE	61	77		
24 Hoosier on LGE	5	6		
25 Total Load	1,791	2,737	1,791.00	2,737.00
Export (Delivered):				
26 IMEA	146	146		
27 IMPA	155	157		
28 LGE Off-System Sales	8	-		
29 OVEC to SIGE	-	-		
30 Total Exports	309	303	309.00	303.00
31 LGE to KU	1,228	1,020	1,228.00	1,020.00
			3,328.00	4,060.00
32 Losses from Schedule 4, Lines 1 and 8			-27.75	-57.95
33 Peak MW Load			3,300.25	4,002.05

Notes:
(1) Information above was gathered through the Peak Load spreadsheet which is used for FERC Form 1 data collection.
Additionally, information was gathered from the individual billings each month, which also flows into FERC Form 1.
(2) OSS information was gathered through multiple spreadsheets from Revenue Accounting and Transmission groups.

Kentucky Utilities

Prepared by: FR/DH

	February-11	March-11	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	January-12	Total	Other	Summer
Loads:															
1 KU Load (including losses)	1,882,033	1,838,010	1,567,127	1,688,187	1,906,541	2,167,087	2,097,914	1,653,158	1,650,548	1,687,623	1,918,215	2,083,767	22,140,210		
2 EKPC on KU	192,766	183,756	155,967	163,451	164,293	182,579	182,121	147,273	142,289	161,421	192,322	213,632	2,081,870		
3 TVA on KU	30,019	26,656	20,497	22,985	27,885	34,587	29,211	21,634	19,664	26,719	36,278	34,830	330,965		
4 OMU Load (3%)	-	-	-	555	-	1,043	1,328	165	6,757	-	-	-	9,848		
5 BREC on KU	3,047	2,972	2,440	2,382	2,575	2,943	3,367	3,272	3,715	2,495	3,797	4,364	37,370		
6 KMPA Load (3%)	53,933	54,624	50,868	58,455	71,032	79,177	77,514	57,137	49,740	51,011	56,115	56,274	715,880		
7 Total Load	2,161,798	2,106,018	1,796,898	1,936,015	2,172,326	2,467,416	2,391,455	1,882,639	1,872,713	1,929,269	2,206,727	2,392,867	25,316,143	16,402,307	8,913,836
Export (Delivered):															
8 KU Off-System Sales	10,003	1,971	14	13,001	23,568	12,175	4,828	384	29,307	2,890	542	265	98,948		
9 AMEM - Pass Through	-	-	2,400	-	-	-	-	-	12,000	2,400	11,338	51,500	79,638		
10 CARGILL - Pass Through	31,261	100	-	23,399	2,400	-	-	20,527	13,749	70	-	-	91,506		
11 OMU Exports	165,206	183,023	175,905	50,051	156,463	143,444	137,842	155,042	106,507	137,874	176,030	158,940	1,746,327		
12 KMPA Exports	-	-	-	-	-	-	-	-	59	-	-	-	59		
13 Constellation - Pass Through	-	-	-	11,734	4,740	24,485	34,163	25,048	34,099	-	-	-	134,269		
14 TEA - Pass Through	-	-	-	-	-	-	-	-	59	66	-	-	125		
15 TVA (OATT) - Pass Through	-	-	308	-	-	-	-	-	-	-	-	-	308		
16 Total Exports	206,470	185,094	178,627	98,185	187,171	180,104	176,833	201,001	195,780	143,300	187,910	210,705	2,151,180	1,406,071	745,109
17 BTM (0.5%) - OMU Network Load	64,375	67,851	62,989	71,662	86,097	103,156	96,293	73,876	61,587	65,420	69,832	70,719	893,857		
18 BTM (0.5%) - KMPA Gen	-	-	-	1,054	4,315	9,837	4,422	858	1,839	-	1,479	1,872	25,677		
19 Total BTM	64,375	67,851	62,989	72,716	90,412	112,993	100,715	74,734	63,426	65,420	71,311	72,591	919,534		
20 Losses at 0.5%	322	339	315	364	452	565	504	374	317	327	357	363	4,598		
21 Total MWH Input														17,808,378	9,658,945
22 Losses from Schedule 5, Lines 5 and 12														-471,986	-260,179
23 Total MWH Output														17,336,391	9,398,766

Louisville Gas and Electric

	February-11	March-11	April-11	May-11	June-11	July-11	August-11	September-11	October-11	November-11	December-11	January-12	Total	Other	Summer
Loads:															
23 LGE Load (including losses)	903,869	935,217	852,840	998,568	1,189,433	1,431,090	1,316,506	968,118	877,979	870,461	958,046	988,020	12,290,147		
24 EKPC on LGE	25,617	24,530	20,953	24,482	30,141	37,883	33,856	23,583	21,869	22,649	27,706	29,346	322,615		
25 Hoosier on LGE	3,006	3,093	2,628	3,247	3,465	3,908	3,767	3,220	3,081	2,998	3,210	3,263	38,886		
26 Total Load	932,492	962,840	876,421	1,026,297	1,223,039	1,472,881	1,354,129	994,921	902,929	896,108	988,962	1,020,629	12,651,648	7,606,677	5,044,971
Export (Delivered):															
27 IMEA	87,925	74,691	45,921	89,073	102,288	100,626	86,582	74,691	75,238	61,640	90,715	99,872	989,262		
28 IMPA	93,431	79,319	48,912	94,516	107,515	106,729	90,741	77,329	79,575	65,340	97,587	105,971	1,046,965		
29 LGE Off-System Sales	155,240	139,458	45,904	124,917	96,244	96,890	49,158	108,739	205,726	207,341	158,716	95,688	1,484,021		
30 OVEC to SIGE	-	-	-	-	-	-	-	-	-	-	-	-	-		
31 Total Exports	336,596	293,468	140,737	308,506	306,047	304,245	226,481	260,759	360,539	334,321	347,018	301,531	3,520,248	2,422,716	1,097,532
32 LGE to KU	484,518	444,877	370,225	397,072	364,002	440,065	446,201	438,994	458,456	438,203	561,790	610,428	5,454,831	3,765,569	1,689,262
33 Total MWH Input														13,794,962	7,831,765
34 Losses from Schedule 4, Lines 5 and 12														-115,779	-83,625
35 Total MWH Output														13,679,183	7,748,140

Information above was gathered through the Peak Load spreadsheet which is used for FERC Form 1 data collection. Additionally, information was gathered from the individual billings each month, which also flows into FERC Form 1
OSS information was gathered through multiple spreadsheets from Revenue Accounting and Transmission groups.

LGEE Loss Summary

	LGE Loss Summary		Transmission Losses		Generation Losses	
	Season	Month	Fixed	Variable	Fixed	Variable
1	O	01	1,944	8,405	1,405	3,124
2	O	02	1,753	7,950	1,165	3,114
3	O	03	1,970	8,159	1,205	3,317
4	O	04	1,923	6,323	1,217	2,547
5	O	05	1,978	9,932	1,207	3,076
6	S	06	1,877	13,384	1,289	3,615
7	S	07	1,933	16,655	1,542	4,380
8	S	08	1,940	15,067	1,454	3,936
9	S	09	1,915	8,781	1,376	2,872
10	O	10	1,999	7,087	1,180	2,917
11	O	11	1,937	6,926	1,273	2,856
12	O	12	1,960	8,252	1,402	3,072
13		Total	23,129	116,921	15,715	38,826
14		Summer Corona	1,609			
15	S	Total LGE Summer	9,274	53,887	5,661	14,803
16		Other Corona	3,204			
17	O	Total LGE Other	18,668	63,034	10,054	24,023

	KU Loss Summary		Transmission Losses		Generation Losses	
	Season	Month	Fixed	Variable	Fixed	Variable
18	O	01	3,246	66,020	1,272	2,314
19	O	02	2,937	65,153	1,209	2,146
20	O	03	3,279	51,357	1,244	2,220
21	O	04	3,200	40,542	1,058	1,929
22	O	05	3,312	41,568	1,190	2,000
23	S	06	3,155	59,549	1,405	2,449
24	S	07	3,247	64,025	1,459	2,832
25	S	08	3,260	61,754	1,436	2,666
26	S	09	3,187	42,213	1,154	1,686
27	O	10	3,306	42,719	1,079	1,752
28	O	11	3,189	49,382	1,089	1,865
29	O	12	3,271	54,623	1,225	1,925
30		Total	38,589	638,905	14,820	25,784
31		Summer Corona	4,702			
32	S	Total KU Summer	17,551	227,541	5,454	9,633
33		Other Corona	9,365			
34	O	Total KU Other	35,105	411,364	9,366	16,151

	LGEE Loss Summary		Transmission Losses		Generation Losses	
	Season	Month	Fixed	Variable	Fixed	Variable
35	O	01	5,190	74,425	2,677	5,438
36	O	02	4,690	73,103	2,374	5,260
37	O	03	5,249	59,516	2,449	5,537
38	O	04	5,123	46,865	2,275	4,476
39	O	05	5,290	51,500	2,397	5,076
40	S	06	5,032	72,933	2,694	6,064
41	S	07	5,180	80,680	3,001	7,212
42	S	08	5,200	76,821	2,890	6,602
43	S	09	5,102	50,994	2,530	4,558
44	O	10	5,305	49,806	2,259	4,669
45	O	11	5,126	56,308	2,362	4,721
46	O	12	5,231	62,875	2,627	4,997
47		Total	61,718	755,826	30,535	64,610
48		Summer Corona	6,311			
49	S	Total LGEE Summer	26,825	281,428	11,115	24,436
50		Other Corona	12,569			
51	O	Total LGEE Other	53,773	474,398	19,420	40,174

Notes:
(1) Includes Corona Losses from Workpaper 3

Summer Peak Hour 2011-07-11-1600

		Transmission Losses		Generation Losses	
		Fixed (1)	Variable	Fixed	Variable
1	KU	5.8	137.8	2.4	5.4
2	LG&E	3.0	43.5	2.9	8.5
3	Combined	8.9	181.3	5.3	13.9

Winter Peak Hour 2011-02-11-0800

		Transmission Losses		Generation Losses	
		Fixed (1)	Variable	Fixed	Variable
4	KU	5.8	184.5	2.3	6.1
5	LG&E	3.1	16.5	2.1	6.0
6	Combined	9.0	201.0	4.4	12.1

		Corona Losses (MW)
		Fixed (1)
7	KU	1.606
8	LG&E	0.549
9	Combined	2.155

Notes:
(1) Includes Corona Losses from Workpaper 3

Hour	LG&E Load	KU on LG&E	EKPC on LG&E	HE on LG&E	LG&E T Loss-f	LG&E T Loss-v	LG&E G Loss-f	LG&E G Loss-v	Net Export	BLG Export	Month
2011-02-01-0100	1217.7	6.3	35.6	4.3	2.6	11.5	1.7	4.6	1394.6	0	02
2011-02-01-0200	1179.1	6	34.4	4.4	2.6	11	1.7	4.4	1373.9	0	02
2011-02-01-0300	1147.9	5.8	33.6	4	2.6	10.8	1.7	4.3	1354.7	0	02
2011-02-01-0400	1138.1	5.6	33	4	2.6	11.6	1.7	4.3	1374.9	0	02
2011-02-01-0500	1149.1	5.7	33.8	3.9	2.6	12	1.7	4.5	1398.1	0	02
2011-02-01-0600	1201.1	6	37.3	4	2.6	12.5	1.7	4.6	1379.2	0	02
2011-02-01-0700	1347.6	6.8	41.9	4.1	2.6	15.3	1.7	5.6	1454.3	0	02
2011-02-01-0800	1429.8	7.2	43.4	4.3	2.6	15.6	1.7	5.6	1354.1	0	02
2011-02-01-0900	1431	7.1	41.9	4.7	2.6	15.6	1.7	5.5	1329.5	0	02
2011-02-01-1000	1424.8	7	41	4.6	2.6	15.4	1.7	5	1236.6	0	02
2011-02-01-1100	1440.5	7	40.8	4.6	2.6	14	1.7	4.6	1122.7	0	02
2011-02-01-1200	1442.4	6.9	40.3	4.5	2.6	14.3	1.7	4.7	1132	0	02
2011-02-01-1300	1438.7	6.8	40.3	4.5	2.6	14.5	1.7	4.8	1159.1	0	02
2011-02-01-1400	1394.7	6.7	39.4	4.4	2.6	13.6	1.7	4.6	1138.9	0	02
2011-02-01-1500	1371.6	6.6	39	4.6	2.6	13.2	1.7	4.3	1098	0	02
2011-02-01-1600	1388.5	6.7	39.7	4.6	2.6	13.2	1.7	4.2	1038.9	0	02
2011-02-01-1700	1408.8	6.8	41.6	4.3	2.6	13.5	1.7	4.3	1064.8	0	02
2011-02-01-1800	1448.7	7	44.2	4.3	2.6	14.7	1.7	4.6	1129.1	0	02
2011-02-01-1900	1483.7	7.2	45.7	4.4	2.6	15.1	1.7	4.8	1162.1	0	02
2011-02-01-2000	1450.8	7.1	45.2	4.7	2.6	15	1.7	4.6	1149.2	0	02
2011-02-01-2100	1414.2	7	44	4.7	2.6	14.5	1.7	4.6	1163.9	0	02
2011-02-01-2200	1337.9	6.6	41.1	4.6	2.6	12.8	1.7	4.5	1190.9	0	02
2011-02-01-2300	1255.5	6.1	37.2	4.2	2.6	11.5	1.7	4.1	1168.2	0	02
2011-02-02-0000	1140.4	5.7	32.8	4	2.6	9	1.7	3.4	1062.1	0	02
2011-02-02-0100	1076.3	5.4	30.7	4.3	2.6	8.1	1.7	3.2	1029.2	0	02
2011-02-02-0200	1046.7	5.3	30.5	4.2	2.6	7.9	2.1	3.3	1168.7	0	02
2011-02-02-0300	1071.2	5.4	32.4	4.1	2.6	8.1	2.1	3.5	1273.5	0	02
2011-02-02-0400	1101.7	5.7	35.5	4.2	2.6	8.3	2	3.6	1282.3	0	02
2011-02-02-0500	1162.1	6.1	38.3	4.3	2.6	9.4	2.1	4.2	1451.1	0	02
2011-02-02-0600	1230.2	7	42.9	4.5	2.6	10.5	2.1	4.6	1495.4	0	02
2011-02-02-0700	1387.9	8.1	49.3	4.7	2.6	13.1	2.1	5.6	1531.5	0	02
2011-02-02-0800	1502.7	9	51.8	4.6	2.6	15.4	2.1	6.5	1611.9	0	02
2011-02-02-0900	1511.5	9	50.4	4.6	2.6	15.2	2.1	6.3	1585.1	0	02
2011-02-02-1000	1514.9	9.3	49.8	4.8	2.6	15.1	2.1	6.2	1560.6	0	02
2011-02-02-1100	1544.2	9.1	49.4	4.9	2.6	15.6	2.1	6.4	1580	0	02
2011-02-02-1200	1552	9.1	49	4.7	2.6	15.7	2.1	6.4	1549	0	02
2011-02-02-1300	1558.5	9	48.6	4.5	2.6	15.9	2.1	6.8	1617.1	0	02
2011-02-02-1400	1559.7	8.9	48.3	4.5	2.6	16	2.1	6.7	1606.8	0	02
2011-02-02-1500	1554.9	8.8	47.3	4.5	2.6	15.8	2.1	6.6	1601.7	0	02
2011-02-02-1600	1538.9	8.7	47.9	4.6	2.6	15.6	2.1	6.5	1595	0	02
2011-02-02-1700	1537.9	8.6	50.4	5	2.6	15.6	2.1	6.9	1654.1	0	02
2011-02-02-1800	1556.3	9	52.5	5	2.6	15.6	2.1	6.7	1595.9	0	02
2011-02-02-1900	1616.8	9.4	56.5	5	2.6	16.6	2.1	6.5	1492.9	0	02
2011-02-02-2000	1618.7	9.4	57.6	5	2.6	16.6	2.1	6.5	1486	0	02

Hour	KU Load	KU on LG&E	KU on EKPC	EKPC on KU	BREC on KU	TVA on KU	OMU on KU	KMPA on KU	KU T Loss-f	KU T Loss-v	KU G Loss-f	KU G Loss-v	Net Export	OMU Export	PADP Gen	Month
2011-02-01-0100	2345.7	6.3	59.6	280.6	5	37.6	82	68.6	4.4	85.8	1.9	2.1	-1050.5	146.1	0	02
2011-02-01-0200	2259.9	6	57.9	265.6	4.9	35.2	83.5	65	4.4	82.9	1.9	1.9	-924.7	200.2	0	02
2011-02-01-0300	2191.3	5.8	56.9	257.6	4.7	33.7	82.5	63.8	4.4	82.7	1.9	1.8	-891.2	209	0	02
2011-02-01-0400	2131.8	5.6	56.5	257.6	4.7	32.5	83.8	63.4	4.4	88.1	1.9	1.9	-713	261.3	0	02
2011-02-01-0500	2137.1	5.7	56.5	259.3	4.5	32.5	85.3	64.1	4.4	88	1.9	2.1	-658.3	285.5	0	02
2011-02-01-0600	2244.3	6	58.2	274.8	5.3	33.8	86.3	66.1	4.4	92.3	1.9	2.3	-679.2	282.5	0	02
2011-02-01-0700	2500.3	6.8	62.4	286.8	5.5	37.6	91.7	72.1	4.3	103.6	1.9	3.5	-549.8	277.5	0	02
2011-02-01-0800	2682.1	7.2	67.2	271.4	5.6	43	102.2	82.5	4.3	100	1.9	3.5	-768.4	277	0	02
2011-02-01-0900	2691.9	7.1	68.7	287	5.7	40.3	110.7	88.1	4.3	100.7	1.9	3.5	-802.1	259.3	0	02
2011-02-01-1000	2698.6	7	69	273.9	6.1	38.8	111.1	91.6	4.3	100.1	1.9	3.5	-811.1	222.6	0	02
2011-02-01-1100	2693.2	7	68.6	279.1	5.4	38.7	111.1	92.6	4.4	92.6	1.9	3.1	-1025.6	139.2	0	02
2011-02-01-1200	2651	6.9	67.8	248.7	5.9	38.1	111	93.1	4.4	90.2	1.9	3	-973.1	146.9	0	02
2011-02-01-1300	2613.9	6.8	67	275.6	6	37.6	110	93.3	4.4	90.3	1.8	3.2	-891.5	181	0	02
2011-02-01-1400	2572.4	6.7	66.8	272.8	5.7	37.1	108.8	92.7	4.4	85.9	1.8	2.9	-969.7	143.2	0	02
2011-02-01-1500	2589.4	6.6	67.4	265.5	5.9	36.7	111.3	91.2	4.4	86.2	1.8	3.1	-898.7	166	0	02
2011-02-01-1600	2575.3	6.7	66.9	274.1	6.1	36.9	111.4	89.8	4.4	88.3	1.8	3.3	-812.7	181	0	02
2011-02-01-1700	2602.6	6.8	67.8	275.4	6.3	38.4	108.4	87.5	4.4	91.7	1.8	3.4	-803	190.5	0	02
2011-02-01-1800	2624.9	7	68.9	238.4	5.8	41.1	109.3	86.5	4.4	94.1	1.8	3.5	-723.5	205.5	0	02
2011-02-01-1900	2663.8	7.2	69.2	302.1	5.5	43.6	111.1	87.6	4.4	92.3	1.8	3.7	-789.1	204.2	0	02
2011-02-01-2000	2622.6	7.1	68.4	289	5.7	44.3	112.1	87.7	4.4	93.4	1.8	3.6	-713.7	256.7	0	02
2011-02-01-2100	2563.1	7	66.5	273.6	6	43.4	110.2	89.2	4.4	90.2	1.8	3.4	-687.2	282	0	02
2011-02-01-2200	2507.5	6.6	64.8	209.9	6.6	42.3	103.5	89.6	4.4	82.9	1.8	3	-751.7	205	0	02
2011-02-01-2300	2368.7	6.1	61.7	207	6	40.3	99.1	87.9	4.4	79.3	1.8	2.5	-830.1	182.7	0	02
2011-02-02-0000	2254.8	5.7	59.2	259.1	6.1	39.4	100.7	85.1	4.4	67.9	1.8	1.7	-1208.7	5.4	0	02
2011-02-02-0100	2176.4	5.4	57.5	224.2	5	38.8	96.9	81.1	4.4	58.5	1.8	1.6	-1101	62.2	0	02
2011-02-02-0200	2133.6	5.3	56.1	215.2	5.4	41	96.4	79.9	4.4	65.9	1.8	1.8	-950.7	105.5	0	02
2011-02-02-0300	2110	5.4	57.9	216.3	5.3	44.4	98.6	79.9	4.4	68.5	1.8	1.7	-899.7	151.2	0	02
2011-02-02-0400	2176.8	5.7	60.6	227	5.2	47	96.1	79.4	4.4	69.7	1.8	1.8	-955	156	0	02
2011-02-02-0500	2336.8	6.1	63.4	169.1	5	48.8	95.2	80.5	4.4	77.7	1.8	1.9	-1049.8	155.8	0	02
2011-02-02-0600	2567.8	7	68.1	194.7	5.6	52.8	96.9	83.3	4.4	88.2	1.8	2.4	-1133.3	155	0	02
2011-02-02-0700	2924.8	8.1	74.6	226.9	5.4	58.2	102.9	89.2	4.3	112.3	1.9	3.4	-1207.1	154.8	0	02
2011-02-02-0800	3226	9	81.8	238.4	5.4	64.2	113.3	99.3	4.3	124.3	1.9	4.5	-1232.2	149.9	0	02
2011-02-02-0900	3300.9	9	84.2	232.4	6	62.8	119.2	103.1	4.3	126.6	1.9	4.6	-1250.3	142.5	0	02
2011-02-02-1000	3382	9.3	84.9	235.4	6.4	63	121.8	105.2	4.3	133.4	1.9	4.8	-1295.4	137.9	0	02
2011-02-02-1100	3356	9.1	85.9	238.8	6.8	63.9	123.4	106.3	4.3	134.6	1.9	4.8	-1275.6	137.7	0	02
2011-02-02-1200	3363.5	9.1	86.2	239.7	6.6	62.9	123.4	106.9	4.3	136.2	2	4.8	-1235.3	138.5	0	02
2011-02-02-1300	3378.4	9	85.4	236.6	6.5	62.3	123.5	106.1	4.3	141.1	2	4.7	-1315.8	137.3	0	02
2011-02-02-1400	3340.1	8.9	85.3	232.6	7.3	60.8	125.9	104.4	4.3	142.4	2	4.7	-1293.7	137.4	0	02
2011-02-02-1500	3329	8.8	84.5	230.2	6.9	60.1	127.1	103.6	4.3	141.5	2	4.6	-1289.9	137.4	0	02
2011-02-02-1600	3260.3	8.7	83.9	232.4	7.1	60.1	125.4	102.5	4.3	139.7	2	4.5	-1250.9	138.6	0	02
2011-02-02-1700	3267.5	8.6	84.2	273.5	7.4	61.6	110.9	100.9	4.3	142.4	1.9	4.4	-1376.6	138.8	0	02
2011-02-02-1800	3385	9	85	325.2	7.4	64.4	112.4	102.1	4.3	138.9	1.9	4.6	-1384.8	180.4	0	02
2011-02-02-1900	3495.9	9.4	86.9	325.3	6.7	68.5	119	106.7	4.3	143.5	1.9	4.9	-1408.1	233.8	0	02
2011-02-02-2000	3498	9.4	87.8	340	6.3	69.5	122.9	108.5	4.3	146.4	1.9	4.9	-1405.7	260.1	0	02

LGE & KU - CORONA LOSS ESTIMATE

		VOLTAGE (kV)	MILES	CORONA PEAK LOSS FACTOR (MW Mile)	CORONA LOSSES (MW)	CORONA WINTER HOURS & LOSSES (MWH)	CORONA SUMMER HOURS & LOSSES (MWH)	CORONA TOTAL LOSSES (MWH)
A.	Fair Weather Corona Losses							
	LGE					5,832	2,928	
1		345	172	0.0032	0.549	3,204	1,609	4,813
2		161	116	0.0000	0.000	0	0	0
3		138	334	0.0000	0.000	0	0	0
4		69	289	0.0000	0.000	0	0	0
5	Subtotal		911		0.549	3,204	1,609	4,813
	KU					5,832	2,928	
6		500	57	0.0060	0.341	1,990	999	2,989
7		345	395	0.0032	1.265	7,375	3,703	11,078
8		161	518	0.0000	0.000	0	0	0
9		138	888	0.0000	0.000	0	0	0
10		69	2,218	0.0000	0.000	0	0	0
11	Subtotal		4,076		1.606	9,365	4,702	14,067
12	TOTAL		4,987		2.155	12,569	6,311	18,880
B.	Unmetered Station Use							
13	Estimated Unmetered Substation Use at				0.0010			

NOTE:
(1) Lines 5 and 11 loss results included in Schedules 3, 4, and 5.

LGE & KU

	Voltage by Company	Number of Miles LGE	KU	Total
1	**LGE**			
2	Overhead			
3	345	171.7		
4	161	116.4		
5	138	329.6		
6	69	286.3		
7	Total Overhead	904.0		904.0
8				
9	Underground			
10	138	4.0		
11	69	2.9		
12	Total Underground	6.9		6.9
13				
14	**Total LGE**	910.9		910.9
15				
16	**KU**			
17	500		56.9	
18	345		395.2	
19	161		518.2	
20	138		887.6	
21	69		2,218.4	
22				
23	**Total KU**		4,076.3	4,076.3
24				
25				
26	**Total Pole Miles**	910.9	4,076.3	4,987.2

Appendix B

Results of LG&E 2010 Loss Analysis

LG&E

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	2,852	MW
ANNUAL SYSTEM INPUT	12,966,029	MWH
ANNUAL SALES	12,399,868	MWH
SYSTEM LOSSES @ INPUT	566,161	or 4.37%
SYSTEM LOAD FACTOR	51.9%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	Input	% TOTAL	--- MWH ---	Input	% TOTAL
TRANS	500,345,138 69	43.5	1.53%	27.43%	132,516	1.02%	23.41%
PRIM SUBS	33,12,1	16.2	0.57%	10.21%	70,977	0.55%	12.54%
PRIMARY	33,12,1	55.2	1.94%	34.83%	160,720	1.24%	28.39%
SECONDARY	120/240,to,477	43.7	1.53%	27.54%	201,948	1.56%	35.67%
TOTAL		158.6	5.56%	100.00%	566,161	4.37%	100.00%

SUMMARY OF LOSS FACTORS

		CUMMULATIVE SALES EXPANSION FACTORS			
SERVICE	KV	DEMAND (Peak)		ENERGY (Annual)	
		d	1/d	e	1/e
TOT TRANS	500,345,138 69	1.01549	0.98475	1.01033	0.98978
PRIM SUBS	33,12,1	1.02152	0.97894	1.01619	0.98407
PRIMARY	33,12,1	1.04295	0.95882	1.02998	0.97089
SECONDARY	120/240,to,477	1.06325	0.94052	1.05235	0.95025

LG 2010 LOSS ANALYSIS

EXHIBIT 2

SUMMARY OF CONDUCTOR INFORMATION

DESCRIPTION				CIRCUIT MILES	LOADING % RATING	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
--- BULK -----------	500 KV	OR GREATER									
TIE LINES				0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS				0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				0.0		0.000	0.000	0.000	0	0	0
--- TRANS ---------	138 KV	TO	500.00 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	345 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
TRANS2	138 KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTOT				0.0		0.000	0.000	0.000	0	0	0
--- SUBTRANS ------	35 KV	TO	138 KV								
TIE LINES				0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS2	KV			0.0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS3	KV			0.0	0.00%	0.000	0.001	0.001	0	6	6
SUBTOT				0.0		0.000	0.001	0.001	0	6	6
PRIMARY LINES				6,278		50.143	2.685	52.828	129,898	23,520	153,418
SECONDARY LINES				3,543		4.845	0.000	4.845	8,557	0	8,557
SERVICES				5,656		9.764	0.824	10.587	26,554	7,214	33,768
TOTAL				15,477		64.752	3.509	68.261	165,009	30,739	195,748

LG 2010 LOSS ANALYSIS

EXHIBIT 3

SUMMARY OF TRANSFORMER INFORMATION

DESCRIPTION		KV CAPACITY		NUMBER	AVERAGE	LOADING	MVA	--------- MW LOSSES --------			------- MWH LOSSES ------		
		VOLTAGE	MVA	TRANSFMR	SIZE	%	LOAD	LOAD	NO LOAD	TOTAL	LOAD	NO LOAD	TOTAL
BULK STEP-UP		500	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - BULK			0.0	0	0.0	0.00%	0	0	0.000	0.000	0	0	0
BULK - TRANS1		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
BULK - TRANS2		138	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 STEP-UP		345	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 - TRANS2		138	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 STEP-UP		138	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS1		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2-SUBTRANS3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3 STEP-UP		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN2		66	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-SUBTRAN3		35	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
							DISTRIBUTION SUBSTATIONS						
TRANS1 -	345	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	345	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	345	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	138	33	115.5	4	28.9	60.99%	70	0.209	0.205	0.415	503	1,501	2,004
TRANS2 -	138	12	1,464.0	50	29.3	80.26%	1,175	3.771	2.805	6.576	9,059	19,624	28,683
TRANS2 -	138	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	12	1,817.3	81	22.4	89.16%	1,620	5.000	3.745	8.745	12,012	25,976	37,988
SUBTRAN1-	69	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2-	66	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			172.7	38	4.5	86.05%	149	0.870	0.307	1.177	2,090	2,687	4,777
LINE TRANSFRMR			5,499.8	86,403	63.7	45.60%	2,508	12.631	14.398	27.028	26,952	126,123	153,074
			===========	===========	===========	===========		===========	===========	===========	===========	==========	===========
TOTAL			9,069	86,576				22.481	21.460	43.941	50,615	175,911	226,527

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 2852 MW

BULK TIE LINES
LOAD 0.00% MW
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

BULK LINES
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

BULK STEP UP
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

BULK-BULK
LOADING 0.00%
NO LOAD 0 MW
LOAD 0 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS TIE LINES
LOAD 0.00% MW
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

BULK-TRANS1 STEP DOWN
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

TRAN1-TRAN2 STEP DOWN
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

BULK-TRANS2 STEP DOWN
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS 1&2 STEP UPS
LDNG TR1SU 0.00%
NOLOAD1&2 0.000 MW
LOAD 1&2 0.000 MW
AVSIZ TR1SU 0.0 MVA
NUMBER 0

TRANS1 345.0 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

TRANS2 138.0 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

TRANS CUST
SUBS 0.000 MW
0.000 MVA
LINES MW
MVA

SUBTRANS TIE LINES
LOAD 0.00% MW
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

TRANS1&2-SUBTRANS1
LDNG TR2-ST 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVSIZ TR2 0 MVA
NUMBER 0

SUBTR1&2-SUBTRANS2&3
LOADING 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVG SIZE 0 MVA
NUMBER 0

TRANS1&2- SUBTRANS2
LDNG TR2-ST 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVSIZ TR2-ST 0.00 MVA
NUMBER 0

TRANS1&2-SUBTRANS3
LDNG TR2-ST2 0.00%
NO LOAD 0.00
LOAD 0.00
AVSIZ TR2-ST2 0.00
NUMBER 0

SUBTRANS1,2,&3 STEP UPS
LDNG ST1SU 0.00%
NO LOAD 0.000 MW
LOAD 0.000 MW
AVSIZ ST2 0.0 MVA
NUMBER 0

SUBTRANS1 69 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

SUBTRANS2 66 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.000 MW

SUBTRANS2 35 KV
LOADING 0.00%
LOAD LOSS 0.000 MW
NOLD LOSS 0.001 MW

SUBTRANS CUST
SUBS - MW 0.000
MVA 0.000
LINES- MW
MVA

TO DISTRIBUTION SYSTEM
TOTAL 2865.6 MVA 2808.3 MW

TRANS1 0.0 MVA
0.00%
345 KV

TRANS2 1,245.4 MVA
43.46%
138 KV

SUBTRANS1 1,620.2 MVA
56.54%
69 KV

SUBTRANS2 0.0 MVA
0.00%
66 KV

SUBTRANS3 0.0 MVA
0.00%
35 KV

LG 2010 LOSS ANALYSIS

EXHIBIT 4 PAGE 2 of 2

FROM HIGH VOLTAGE SYSTEM

TOTAL 2,866 MVA 2,808 MW

TRANS1	TRANS2	SUBTRANS1	SUBTRANS2	SUBTRANS3
0.0 MVA	1,245.4 MVA	1,620.2 MVA	0.0 MVA	0.0 MVA
0.00%	43.46%	56.54%	0.00%	0.00%
345 KV	138 KV	69 KV	66 KV	35 KV

DISTRIBUTION SYSTEM LOAD

	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3	PRIM1	PRIM2	PRIM3
VOLTAGE	33	12	1	33	12	1	33	12	1	33	12	1	33	12	1
LOAD MVA	0	0	0	70	1,175	0	0	1,620	0	0	0	0	0	0	0
% SYS TOT	0.00%	0.00%	0.00%	2.46%	41.00%	0.00%	0.00%	56.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NOLD LOSS	0.000	0.000	0.000	0.205	2.805	0.000	0.000	3.745	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LOAD LOSS	0.000	0.000	0.000	0.209	3.771	0.000	0.000	5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
AVG SIZE	0.0	0.0	0.0	28.9	29.3	0.0	0.0	22.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NUMBER	0	0	0	4	50	0	0	81	0	0	0	0	0	0	0
DIVERSITY RATIO	0.000	0.000	0.000	1.000	1.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

PRIMARY LINES

LOADING	2685.191	MW
@ SYS PF	2739.991	MVA
LOAD LOSS	50.143	MW
NOLD LOSS	2.685	MW
TOT LOSS	52.828	MW

PRIM/PRIM TRANSF

LOADING	148.562	MW
NOLD LOSS	0.307	MW
LOAD LOSS	0.870	MW
AVG SIZE	4.54	
NUMBER	38	

PRIM CUST LOADS

NO LINES	0.000	MW
CUST SUB	0.000	MVA
NO LINES	38.300	MW
CO. SUB	39.082	MVA
PRIM WITH	345.000	MW
LINES	375.000	MVA

LINE TRANSFORMERS

LOADING	2286.187	MW	MVA	2534.666
NOLD LOSS	14.398	MW		
LOAD LOSS	12.631	MW		
AVG SIZE	63.7	KVA		
NUMBER	86403			

SECONDARY LINES

LOAD	894.040	MW
LOAD LOSS	4.845	MW
NOLD LOSS	0.000	MW
TOT LOSS	4.845	MW

NO SECONDARY LINES

LOAD 1365.118 MW

SERVICES

LOAD	2254.313	MW
LOAD LOSS	9.764	MW
NOLD LOSS	0.824	MW
TOT LOSS	10.587	MW

CUSTOMER SECONDARY LOAD

2243.726 MW

0

LG 2010 LOSS ANALYSIS

EXHIBIT 5

SUMMARY of SALES and CALCULATED LOSSES

LOSS # AND LEVEL	MW LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC	MWH LOAD	NO LOAD +	LOAD =	TOT LOSS	EXP FACTOR	CUM EXP FAC
1 BULK XFMMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0	0
2 BULK LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
3 TRANS1 XFMR	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
4 TRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
5 TRANS2TR1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
6 TRANS GSU	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	0.0	4.43	39.07	43.50	0.000000	0.000000	0	29,013	103,503	132,516	0.0000000	0.0000000
TOTAL TRAN	2,852.0	4.43	39.07	43.50	1.015489	1.015489	12,966,029	29013	103503	132,516	1.0103258	1.0103258
8 STR1BLK SD												
9 STR1T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
10 SRT1T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
11 SUBTRANS1 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
12 STR2T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
13 STR2T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
14 STR2S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
15 SUBTRANS2 LINES	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
16 STR3T1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
17 STR3T2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
18 STR3S1 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
19 STR3S2 SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
20 SUBTRANS3 LINES	0.0	0.00	0.00	0.00	0.000000		0	6	0	6	0.0000000	
21 SUBTRANS TOTAL	0.0	0.00	0.00	0.00	0.000000		0	6	0	6	0.0000000	
22 TOT TRANS LOSS FAC	**2,852.0**	**4.43**	**39.07**	**43.50**	**1.015489**	**1.015489**	**12,966,029**	**29,013**	**103,503**	**132,516**	**1.010326**	**1.0103258**
DISTRIBUTION SUBST												
TRANS1	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
TRANS2	1,151.5	3.01	3.98	6.99	1.006108	0.000000	5,338,276	21,126	9,562	30,687	1.0057818	0.0000000
SUBTR1	1,587.8	3.74	5.00	8.74	1.005538	0.000000	6,944,729	25,976	12,012	37,988	1.0055001	0.0000000
SUBTR2	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
SUBTR3	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
WEIGHTED AVERAGE	2,739.2	6.76	8.98	15.74	1.005778	1.021356	12,283,005	47,102	21,574	68,675	1.0056225	1.0160063
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
PRIMARY LINES	2,684.9	2.68	51.01	53.70	1.020408	1.042200	11,989,742	23,520	131,988	155,508	1.0131405	1.0293572
LINE TRANSF	2,286.2	14.40	12.63	27.03	1.011964	1.054669	9,493,517	126,123	26,952	153,074	1.0163883	1.0462266
SECONDARY	2,259.2	0.00	4.84	4.84	1.002149	1.056935	9,340,443	0	8,557	8,557	1.0009169	1.0471860
SERVICES	2,254.3	0.82	9.76	10.59	1.004719	1.061923	9,331,886	7,214	26,554	33,768	1.0036317	1.0509890
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		29.09	126.30	155.39				232,971	319,127	552,098		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	CALC LOSS TO LEVEL b	SALES MW @ GEN c	CUM PEAK EXPANSION FACTORS d	1/d
BULK LINES	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	66.4	1.0	67.4	1.01549	0.98475
PRIM SUBS	38.3	0.8	39.1	1.02136	0.97909
PRIM LINES	345.0	14.6	359.6	1.04220	0.95951
SECONDARY	2,243.7	138.9	2,382.7	1.06192	0.94169
TOTALS	2,693.4	155.3	2,848.8		

DEVELOPMENT of LOSS FACTORS
UNADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	CALC LOSS TO LEVEL b	SALES MWH @ GEN c	CUM ANNUAL EXPANSION FACTORS d	1/d
BULK LINES	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0.00000	0.00000
TOTAL TRANS	536,042	5,535	541,577	1.01033	0.98978
PRIM SUBS	224,991	3,601	228,592	1.01601	0.98425
PRIM LINES	2,340,717	68,717	2,409,434	1.02936	0.97148
SECONDARY	9,298,118	474,102	9,772,220	1.05099	0.95148
TOTALS	12,399,868	551,955	12,951,823		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	67.43	541,577
PRIM SUBS	39.12	228,592
PRIM LINES	359.56	2,409,434
SECONDARY	2,382.66	9,772,220
SUBTOTAL	2,848.77	12,951,823
ACTUAL ENERGY	2,852.00	12,966,029
MISSMATCH	(3.23)	(14,206)
% MISSMATCH	-0.11%	-0.11%

DEVELOPMENT of LOSS FACTORS
ADJUSTED
DEMAND

LOSS FACTOR LEVEL	CUSTOMER SALES MW a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MW @ GEN d	CUM PEAK EXPANSION FACTORS e	f=1/e
BULK LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TRANS LINES	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
TOTAL TRANS	66.4	0.0	1.0	67.4	1.01549	0.98475
PRIM SUBS	38.3	0.0	0.8	39.1	1.02152	0.97894
PRIM LINES	345.0	0.0	14.8	359.8	1.04295	0.95882
SECONDARY	2,243.7	0.0	141.9	2,385.6	1.06325	0.94052
			158.6			
TOTALS	2,693.4	0.0	158.6	2,852.0		

DEVELOPMENT of LOSS FACTORS
ADJUSTED
ENERGY

LOSS FACTOR LEVEL	CUSTOMER SALES MWH a	SALES ADJUST b	CALC LOSS TO LEVEL c	SALES MWH @ GEN d	CUM ANNUAL EXPANSION FACTORS e	f=1/e
BULK LINES	0	0	0	0	0.00000	0.00000
TRANS SUBS	0	0	0	0	0.00000	0.00000
TRANS LINES	0	0	0	0	0.00000	0.00000
SUBTRANS SUBS	0	0	0	0	0.00000	0.00000
TOTAL TRANS	536,042	0	5,535	541,577	1.01033	0.98978
PRIM SUBS	224,991	0	3,643	228,634	1.01619	0.98407
PRIM LINES	2,340,717	0	70,184	2,410,901	1.02998	0.97089
SECONDARY	9,298,118	0	486,797	9,784,915	1.05235	0.95025
			566,159			
TOTALS	12,399,868	0	566,161	12,966,027		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	0.00	0
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	67.43	541,577
PRIM SUBS	39.12	228,634
PRIM LINES	359.82	2,410,901
SECONDARY	2,385.63	9,784,915
	2,852.00	12,966,027
ACTUAL ENERGY	2,852.00	12,966,029
MISSMATCH	0.00	(2)
% MISSMATCH	0.00%	0.00%

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

	MW	Unadjusted	MWH	Unadjusted
Service Drop Losses	10.59	10.58	33,768	33,756
Secondary Losses	4.84	4.84	8,557	8,554
Line Transformer Losses	27.03	27.02	153,074	153,022
Primary Line Losses	53.70	53.67	155,508	155,455
Distribution Substation Losses	15.74	15.73	68,675	68,652
Transmission System Losses	43.50	43.50	132,516	132,516
Total	155.39	155.34	552,098	551,955

Mismatch Allocation by Segment

	MW	MWH
Service Drop Losses	-0.31	-1,143
Secondary Losses	-0.14	-290
Line Transformer Losses	-0.78	-5,183
Primary Line Losses	-1.55	-5,265
Distribution Substation Losses	-0.45	-2,325
Transmission System Losses	0.00	0
Total	-3.23	-14,206

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	10.89	6.9%	34,899	6.2%
Secondary Losses	4.98	3.1%	8,844	1.6%
Line Transformer Losses	27.80	17.5%	158,205	27.9%
Primary Line Losses	55.22	34.8%	160,720	28.4%
Distribution Substation Losses	16.18	10.2%	70,977	12.5%
Transmission System Losses	43.50	27.4%	132,516	23.4%
Total	158.57	100.0%	566,161	100.0%

Loss Factors by Segment	**MW**	**MWH**	
Retail Sales from Service Drops	2,243.726	9,298,118	
Adjusted Service Drop Losses	10.888	34,899	
Input to Service Drops	2,254.614	9,333,017	
Service Drop Loss Factor	**1.00485**	**1.00375**	
Output from Secondary	2,254.614	9,333,017	
Adjusted Secondary Losses	4.983	8,844	
Input to Secondary	2,259.597	9,341,861	
Secondary Conductor Loss Factor	**1.00221**	**1.00095**	
Output from Line Transformers	2,259.597	9,341,861	
Adjusted Line Transformer Losses	27.796	158,205	
Input to Line Transformers	2,287.393	9,500,066	
Line Transformer Loss Factor	**1.01230**	**1.01694**	
Retail Sales from Primary	345.000	2,340,717	
Req. Whls Sales from Primary	0.000	0	
Input to Line Transformers	2,287.393	9,500,066	
Output from Primary Lines	2,632.393	11,840,783	
Adjusted Primary Line Losses	55.224	160,720	
Input to Primary Lines	2,687.617	12,001,503	
Primary Line Loss Factor	**1.02098**	**1.01357**	
Output Pl from Distribution Substations	2,687.617	12,001,503	
Req. Whls Sales from Substations	0.000	0	
Retail Sales from Substations	38.300	224,991	
TotalOutput from Distribution Substations	2,725.917	12,226,494	
Adjusted Distribution Substation Losses	16.183	70,977	
Input to Distribution Substations	2,742.100	12,297,471	
Distribution Substation Loss Factor	**1.00594**	**1.00581**	
Retail Sales at from SubTransmission	66.400	536,042	
Req. Whls Sales from SubTransmission	0.000	0	
Non-Req. Whls Sales from SubTransmission	0.000	0	
Losses	0.000	0	4457
Input to Distribution Substations	2,742.100	12,297,471	
Output from SubTransmission	2,808.500	12,833,513	2,852.000
SubTransmission System Losses	43.500	132,516	43.500
Input to Transmission	2,852.000	12,966,029	43.500
TotTransmission System Loss Factor	**1.01549**	**1.01033**	43.500

DEMAND MW — **SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE** — **EXHIBIT 9**
PAGE 1 of 2

	SERVICE LEVEL		SALES MW	LOSSES	SECONDARY	PRIMARY	SUBSTATION	SUBTRANS	TRANSMISSION
1	**SERVICES**								
2	SALES		2,243.7		2,243.7				
3	LOSSES			10.9	10.9				
4	INPUT				2,254.6				
5	**EXPANSION FACTOR**	**1.00485**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			5.0	5.0				
9	INPUT				2,259.6				
10	**EXPANSION FACTOR**	**1.00221**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			27.8	27.8				
14	INPUT				2,287.4				
15	**EXPANSION FACTOR**	**1.01230**							
16	**PRIMARY**								
17	SECONDARY				2,287.4				
18	SALES		345.0			345.0			
19	LOSSES			55.2	48.0	7.2			
20	INPUT				2,335.4	352.2			
21	**EXPANSION FACTOR**	**1.02098**							
22	**SUBSTATION**								
23	PRIMARY				2,335.4	352.2			
24	SALES		38.3				38.3		
25	LOSSES			16.2	13.9	2.1	0.2		
26	INPUT				2,349.2	354.3	38.5		
27	**EXPANSION FACTOR**	**1.00594**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				2,349.2	354.3	38.5		
37	SALES		66.4						66.4
38	LOSSES			43.5	36.4	5.5	0.6		1.0
39	INPUT				2,385.6	359.8	39.1		67.4
40	**EXPANSION FACTOR**	**1.01549**							
41	**TOTALS** LOSSES			158.6	141.9	14.8	0.8		1.0
42	% OF TOTAL			100%	89.49%	9.34%	0.52%		0.65%
43	SALES		2,693.4		2,243.7	345.0	38.3		66.4
44	% OF TOTAL		100.00%		83.30%	12.81%	1.42%		2.47%
45	INPUT		2,852.0		2,385.6	359.8	39.1		67.4
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.06325**	**1.04295**	**1.02152**		**1.01549**

	ENERGY MWH			**SUMMARY OF LOSSES AND LOSS FACTORS BY DELIVERY VOLTAGE**					**EXHIBIT 9** PAGE 2 of 2
	SERVICE LEVEL		**SALES**	**LOSSES**	**SECONDARY**	**PRIMARY**	**SUBSTATION**	**SUBTRANS**	**TRANSMISSION**
1	**SERVICES**								
2	SALES		9,298,118		9,298,118				
3	LOSSES			34,899	34,899				
4	INPUT				9,333,017				
5	**EXPANSION FACTOR**	**1.00375**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			8,844	8,844				
9	INPUT				9,341,861				
10	**EXPANSION FACTOR**	**1.00095**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			158,205	158,205				
14	INPUT				9,500,066				
15	**EXPANSION FACTOR**	**1.01694**							
16	**PRIMARY**								
17	SECONDARY				9,500,066				
18	SALES		2,340,717.000			2,340,717			
19	LOSSES			160,720	128,948	31,772			
20	INPUT				9,629,014	2,372,489			
21	**EXPANSION FACTOR**	**1.01357**							
22	**SUBSTATION**								
23	PRIMARY				9,629,014	2,372,489			
24	SALES		224,991				224,991		
25	LOSSES			70,977	55,898	13,773	1,306		
26	INPUT				9,684,912	2,386,261	226,297		
27	**EXPANSION FACTOR**	**1.00581**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS								
30	SALES								
31	LOSSES								
32	INPUT								
33	**EXPANSION FACTOR**								
34	**TRANSMISSION**								
35	SUBTRANSMISSION								
36	DISTRIBUTION SUBS				9,684,912	2,386,261	226,297		
37	SALES		536,042						536,042
38	LOSSES			132,516	100,004	24,640	2,337		5,535
39	INPUT				9,784,917	2,410,901	228,634		541,577
40	**EXPANSION FACTOR**	**1.01033**							
41	**TOTALS**	LOSSES		566,161	486,799	70,184	3,643		5,535
42		% OF TOTAL		100%	85.98%	12.40%	0.64%		0.98%
43		SALES	12,399,868		9,298,118	2,340,717	224,991		536,042
44		% OF TOTAL	100.00%		74.99%	18.88%	1.81%		4.32%
45		INPUT	12,966,029		9,784,917	2,410,901	228,634		541,577
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.05235**	**1.02998**	**1.01619**		**1.01033**

Appendix C

Discussion of Hoebel Coefficient

COMMENTS ON THE HOEBEL COEFFICIENT

The Hoebel coefficient represents an established industry standard relationship between peak losses and average losses and is used in a loss study to estimate energy losses from peak demand losses. H. F. Hoebel described this relationship in his article, "Cost of Electric Distribution Losses," Electric Light and Power, March 15, 1959. A copy of this article is attached.

Within any loss evaluation study, peak demand losses can readily be calculated given equipment resistance and approximate loading. Energy losses, however, are much more difficult to determine given their time-varying nature. This difficulty can be reduced by the use of an equation which relates peak load losses (demand) to average losses (energy). Once the relationship between peak and average losses is known, average losses can be estimated from the known peak load losses.

Within the electric utility industry, the relationship between peak and average losses is known as the loss factor. For definitional purposes, loss factor is the ratio of the average power loss to the peak load power loss, during a specified period of time. This relationship is expressed mathematically as follows:

(1) F_{LS} . A_{LS}) P_{LS}

where: F_{LS} = Loss Factor
A_{LS} = Average Losses
P_{LS} = Peak Losses

The loss factor provides an estimate of the degree to which the load loss is maintained throughout the period in which the loss is being considered. In other words, loss factor is the ratio of the actual kWh losses incurred to the kWh losses which would have occurred if full load had continued throughout the period under study.

Examining the loss factor expression in light of a similar expression for load factor indicates a high degree of similarity. The mathematical expression for load factor is as follows:

(2) F_{LD} . A_{LD}) P_{LD}

where: F_{LD} = Load Factor
A_{LD} = Average Load
P_{LD} = Peak Load

This load factor result provides an estimate of the degree to which the load loss is maintained throughout the period in which the load is being considered. Because of the similarities in definition, the loss factor is sometimes called the "load factor of losses." While the definitions are similar, a strict equating of the two factors cannot be made. There does exist, however, a relationship between these two factors which is dependent upon the shape of the load duration curve. Since resistive losses vary as the square of the load, it can be shown mathematically that the loss factor can vary between the extreme limits of load factor and load factor squared. The relationship between load factor and loss factor has become an industry standard and is as follows:

$$(3)\ \ F_{LS}\ .\ H*F_{LD}^{2} + (1-H)*F_{LD}$$

where: F_{LS} = Loss Factor
F_{LD} = Load Factor
H = Hoebel Coeff

As noted in the attached article, the suggested value for H (the Hoebel coefficient) is 0.7. The exact value of H will vary as a function of the shape of the utility's load duration curve. In recent years, values of H have been computed directly for a number of utilities based on EEI load data. It appears on this basis, the suggested value of 0.7 should be considered a lower bound and that values approaching unity may be considered a reasonable upper bound. Based on experience, values of H have ranged from approximately 0.85 to 0.95. The standard default value of 0.9 is generally used.

Inserting the Hoebel coefficient estimate gives the following loss factor relationship using Equation (3):

$$(4)\ \ F_{LS}\ .\ 0.90*F_{LD}^{2} + 0.10*F_{LD}$$

Once the Hoebel constant has been estimated and the load factor and peak losses associated with a piece of equipment have been estimated, one can calculate the average, or energy losses as follows:

$$(5)\ \ A_{LS}\ .\ P_{LS} * [H*F_{LD}^{2} + (1-H)*F_{LD}]$$

where: A_{LS} = Average Losses
P_{LS} = Peak Losses
H = Hoebel Coefficient
F_{LD} = Load Factor

Loss studies use this equation to calculate energy losses at each major voltage level in the analysis.

From:	Hilton, Tim
To:	Whitehouse, Jonathan
Cc:	Brennan, Paul
Subject:	Re: Meter life
Date:	Wednesday, March 16, 2016 8:40:31 AM

20 years.

Sent from my iPad

On Mar 16, 2016, at 8:20 AM, Whitehouse, Jonathan <Jonathan.Whitehouse@lge-ku.com> wrote:

Paul/Tim,

What is the expected life of the RF Focus AXe meters? Thanks.

Jonathan Whitehouse | Advanced Metering Systems Engineer
LG&E and KU Energy LLC | 220 West Main Street | Louisville, KY 40202
Office. 502.627.3504 | Fax. 502.217.4832 | www.lge-ku.com

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 18

Responding Witness: Christopher M. Garrett

Q.1-18. Please provide a quantification of the electric revenue requirement included for the AMS initiative in the test year, including all rate base/capitalization components and all operating expenses. The quantification should include all reductions in rate base/capitalization and operating expenses from savings due to the proposed transition to AMS. Provide all assumptions, data, and calculations.

A.1-18. See attached for an estimate of the AMS revenue requirement for the test year.

2017 Business Plan
LG&E and KU Key Business Unit Projects
Dollars in 000's

	Capital Including 108					Test Year Ended June 30, 2018			
Project	Total Project	2017-2021	Through TYE 6/30/18	Avg. Capital TYE 6/30/18	Avg. Def. Tax Bal. TYE 6/30/18	Cost of Capital	Depreciation	O&M	Total Rev. Reqts.
Advanced Metering Systems (AMS)	$ 319,610	$ 319,610	$ 120,220	$ 52,481	$ 3,668	$ 5,200	$ 1,352	$ 6,703	$ 13,255

2017 Business Plan
LG&E Key Business Unit Projects
Dollars in 000's

Project	Capital Including 108: Total Project	2017-2021	Through TYE 6/30/18	Avg. Capital TYE 6/30/18	Avg. Def. Tax Bal. TYE 6/30/18	Test Year Ended June 30, 2018: Cost of Capital	Depreciation	O&M	Total LGE Rev. Reqts.
Advanced Metering Systems (AMS)	$ 159,805	$ 159,805	$ 60,110	$ 26,241	$ 1,834	$ 2,633	$ 676	$ 3,352	$ 6,660
									Total Elec.
									$ 5,343
									Total Gas
									$ 1,317
						Elec. Split	Elec. Cap/Dep	Elec. O&M	
						0.7	$ 2,316	$ 3,027	
						Gas Split	Gas Cap/Dep	Gas O&M	
						0.3	$ 993	$ 324	

2017 Business Plan
KU Key Business Unit Projects
Dollars in 000's

Project	Capital Including 108					Test Year Ended June 30, 2018			
	Total Project	2017-2021	Through TYE 6/30/18	Avg. Capital TYE 6/30/18	Avg. Def. Tax Bal. TYE 6/30/18	Cost of Capital	Depreciation	O&M	Total KU Rev. Reqts.
Advanced Metering Systems (AMS)	$ 159,805	$ 159,805	$ 60,110	$ 26,241	$ 1,834	$ 2,567	$ 676	$ 3,352	$ 6,595
							KU KY Juris. Cap & Depr.	KU KY Juris. O&M	KU KY Juris. $ 6,066
							$ 2,895	$ 3,171	
							KU Juris. Cap. 89.28%		

2017 Business Plan
LG&E and KU Key Business Unit Projects
Dollars in 000's

CS Projects

LG&E

Project	O&M	Total Rev. Reqts.		Electric	Gas
	Test Year Ended June 30, 2018				
Advanced Metering Systems (AMS)	$ 3,351	$ 3,351		3,027	324

AMS by FERC Account :	3351.49252	Electric	Gas	Electric	Gas
F586-METER EXPENSE	1167.42148	100%		1,167	-
F597-MTCE OF METERS	1427.89998	100%		1,428	-
F878-METER AND HOUSE REGULATOR EXPENSE	6.45402		100%	-	6
F893-MTCE OF METERS AND HOUSE REGULATORS	15.19902		100%	-	15
F903-CUSTOMER RECORDS AND COLLECTION EXPENSES	640.77306	56%	44%	359	282
F910-MISC CUSTOMER SERVICE AND INFORMATION EXPENSE	93.74496	78%	22%	73	21

Key Business Unit Projects
Plant In-Service Amounts by Project
Cumulative In-Service

	6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
LG&E Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
KU Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
Total LG&E and KU														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 6,480	$ 12,960	$ 19,440	$ 26,818	$ 34,196	$ 41,574	$ 48,952	$ 56,330	$ 63,708	$ 23,881

Key Business Unit Projects
Plant In-Service Amounts by Project
Cumulative In-Service

Plant In Service		6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941
Book Depreciation															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 676
Tax Depreciation															
LG&E Projects	MACRS														
Advanced Metering Systems	10	$ -	$ -	$ -	$ -	$ 1,674	$ 1,755	$ 1,917	$ 1,011	$ 1,029	$ 1,052	$ 1,083	$ 1,129	$ 1,221	$ 913
Book/Tax Difference															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 1,599	$ 1,680	$ 1,842	$ 935	$ 954	$ 977	$ 1,008	$ 1,054	$ 1,146	$ 861
Deferred Tax Expense															
LG&E Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 622	$ 653	$ 716	$ 364	$ 371	$ 380	$ 392	$ 410	$ 446	$ 335

Accumulated Deferred Taxes	6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
LG&E Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 622	$ 1,275	$ 1,992	$ 2,356	$ 2,727	$ 3,107	$ 3,499	$ 3,909	$ 4,355	$ 1,834

Key Business Unit Projects
Plant In-Service Amounts by Project
Cumulative In-Service

Plant In Service

		6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 3,240	$ 6,480	$ 9,720	$ 13,409	$ 17,098	$ 20,787	$ 24,476	$ 28,165	$ 31,854	$ 11,941

Book Depreciation

KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 75	$ 676

Tax Depreciation

KU Projects	MACRS														
Advanced Metering Systems	10	$ -	$ -	$ -	$ -	$ 1,674	$ 1,755	$ 1,917	$ 1,011	$ 1,029	$ 1,052	$ 1,083	$ 1,129	$ 1,221	$ 913

Book/Tax Difference

KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 1,599	$ 1,680	$ 1,842	$ 935	$ 954	$ 977	$ 1,008	$ 1,054	$ 1,146	$ 861

Deferred Tax Expense

KU Projects															
Advanced Metering Systems		$ -	$ -	$ -	$ -	$ 622	$ 653	$ 716	$ 364	$ 371	$ 380	$ 392	$ 410	$ 446	$ 335

Accumulated Deferred Taxes

	6/30/17	7/31/17	8/31/17	9/30/17	10/31/17	11/30/17	12/31/17	1/31/18	2/28/18	3/31/18	4/30/18	5/31/18	6/30/18	13 Month Average
KU Projects														
Advanced Metering Systems	$ -	$ -	$ -	$ -	$ 622	$ 1,275	$ 1,992	$ 2,356	$ 2,727	$ 3,107	$ 3,499	$ 3,909	$ 4,355	$ 1,834

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 19

Responding Witness: Gregory J. Meiman

Q.1-19. Please provide the incentive compensation expense for (a) 2015, (b) 2016, (c) the base year, and (d) the test year by incentive compensation plan and by goal or target for each plan. This includes incentive compensation expense incurred directly by the Company and the expense assigned and allocated to the Company from the Service Company.

A.1-19. The Company has one incentive compensation plan, the Team Incentive Award (TIA) that is charged to LGE and included in its revenue requirement. The incentive measures are re-evaluated annually. However, for the sake of completeness, the table below assumes the measures and weightings used for 2017 will apply in 2018 as well for purposes of categorizing the TIA for the forecast test year. See the response to AG 1-210 for a copy of the plan.

	2015	**2016**	**Base Period**	**Test Period**
Total Team Incentive Award				
Net Income	6,169,284.95	3,155,809	2,475,210	-
Cost Control	-	-	196,134	1,509,271
Customer Reliability	-	-	196,134	1,509,271
Customer Satisfaction	1,683,396	1,720,441	1,619,281	1,509,271
Corporate Safety	-	1,617,665	1,522,548	1,509,271
Individual / Team Effectiveness	3,801,601	4,001,026	3,765,770	4,829,668
Total	11,654,282	10,494,940	9,775,077	10,866,752

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 20

Responding Witness: Gregory J. Meiman

Q.1-20. Please provide a copy of each incentive compensation plan.

A.1-20. See the response to AG 1-210.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 21

Responding Witness: Christopher M. Garrett

Q.1-21. Please provide a schedule showing the actual amount of property taxes paid by the Company during 2016 to each taxing authority and in total.

A.1-21. The Company paid $26,691,795 in property tax in 2016. See attached.

Louisville Gas & Electric Company
Property Tax Payment History
For payments between 01/01/2016 and 12/31/2016

Payee Description	State	Assessment Year	Date	Amount
BARDSTOWN INDEPENDENT SCHOOL DIS	KY	2015	1/18/2016	20,253.16
CITY OF BARDSTOWN KY	KY	2015	1/18/2016	2,364.20
CITY OF BEDFORD	KY	2015	1/18/2016	247.70
CITY OF EMINENCE	KY	2015	1/18/2016	1,077.10
CITY OF NEW CASTLE	KY	2015	1/18/2016	660.50
MERCER COUNTY SHERIFF	KY	2015	1/18/2016	15,271.57
SHERIFF OF BARREN COUNTY	KY	2015	1/18/2016	818.09
SHERIFF OF BRECKINRIDGE COUNTY	KY	2015	1/18/2016	752.38
SHERIFF OF GREEN COUNTY	KY	2015	1/18/2016	142,114.94
SHERIFF OF LARUE COUNTY	KY	2015	1/18/2016	256,006.93
SHERIFF OF MARION COUNTY	KY	2015	1/18/2016	17,838.11
SHERIFF OF OLDHAM COUNTY	KY	2015	1/18/2016	626,151.05
SHERIFF OF SPENCER COUNTY	KY	2015	1/18/2016	995.06
SHERIFF OF TRIMBLE COUNTY	KY	2015	1/18/2016	57,283.92
SHERIFF OF UNION COUNTY	KY	2015	1/18/2016	1,198.01
SHERIFF OF WASHINGTON COUNTY	KY	2015	1/18/2016	516.27
CITY OF AUDUBON PARK	KY	2015	1/21/2016	979.48
CITY OF CLOVERPORT	KY	2015	1/21/2016	330.02
CITY OF ELIZABETHTOWN	KY	2015	1/21/2016	22.47
CITY OF JEFFERSONTOWN	KY	2015	1/21/2016	15,233.75
CITY OF LAGRANGE	KY	2015	1/21/2016	3,274.13
CITY OF MIDDLETOWN	KY	2015	1/21/2016	7,267.83
CITY OF PEWEE VALLEY	KY	2015	1/21/2016	1,617.44
CITY OF RADCLIFF	KY	2015	1/21/2016	3,228.34
CITY OF SIMPSONVILLE	KY	2015	1/21/2016	4,929.69
SHERIFF OF MEADE COUNTY	KY	2015	1/21/2016	312,052.31
SHERIFF OF MUHLENBERG COUNTY	KY	2015	1/21/2016	2,293.70
SHERIFF OF SHELBY COUNTY	KY	2015	1/21/2016	411,890.44
CITY OF MEADOWVIEW ESTATES	KY	2015	1/21/2016	74.66
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	1/25/2016	89.78
SHERIFF OF BELL COUNTY	KY	2014	1/27/2016	10.69
CITY OF CAMPBELLSBURG	KY	2015	1/27/2016	239.37
CITY OF DOUGLASS HILLS	KY	2015	1/27/2016	1,754.60
CITY OF GRAYMOOR DEVONDALE	KY	2015	1/27/2016	831.69
CITY OF HILLVIEW	KY	2015	1/27/2016	3,199.13
CITY OF INDIAN HILLS	KY	2015	1/27/2016	3,220.19
CITY OF KINGSLEY	KY	2015	1/27/2016	470.84
CITY OF MORGANFIELD	KY	2015	1/27/2016	857.27
CITY OF MT WASHINGTON	KY	2015	1/27/2016	2,566.58
CITY OF PIONEER VILLAGE	KY	2015	1/27/2016	1,312.95
CITY OF PROSPECT	KY	2015	1/27/2016	4,237.91
CITY OF ST MATTHEWS	KY	2015	1/27/2016	8,542.75
CITY OF WATTERSON PARK	KY	2015	1/27/2016	1,476.50
SHERIFF OF BELL COUNTY	KY	2015	1/27/2016	1,244.51
SHERIFF OF BULLITT COUNTY	KY	2015	1/27/2016	307,702.94
CITY OF KINGSLEY	KY	2014	2/15/2016	476.18
ANCHORAGE BOARD OF EDUCATION	KY	2015	2/15/2016	21,501.75
CITY OF CRESTWOOD	KY	2015	2/15/2016	546.26
CITY OF EARLINGTON	KY	2015	2/15/2016	80.43
CITY OF GREEN SPRING	KY	2015	2/15/2016	495.20
CITY OF HUNTERS HOLLOW	KY	2015	2/15/2016	29.70

Louisville Gas & Electric Company
Property Tax Payment History
For payments between 01/01/2016 and 12/31/2016

Payee Description	State	Assessment Year	Date	Amount
CITY OF LYNDON	KY	2015	2/15/2016	2,399.05
CITY OF SHEPHERDSVILLE	KY	2015	2/15/2016	10,506.42
CITY OF SPRING VALLEY	KY	2015	2/15/2016	385.21
SHERIFF OF HARDIN COUNTY	KY	2015	2/15/2016	47,402.51
SHERIFF OF HART COUNTY	KY	2015	2/15/2016	90,640.03
SHERIFF OF JEFFERSON COUNTY	KY	2015	2/15/2016	13,868,151.33
SHERIFF OF NELSON COUNTY	KY	2015	2/15/2016	39,109.69
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	2/25/2016	212.28
CITY OF ANCHORAGE	KY	2015	3/3/2016	58,698.31
CITY OF DRUID HILLS	KY	2015	3/3/2016	123.28
CITY OF HOLLOW CREEK	KY	2015	3/3/2016	701.13
CITY OF PINEVILLE	KY	2015	3/3/2016	400.05
CITY OF PLANTATION	KY	2015	3/3/2016	1,502.72
CITY OF RICHLAWN	KY	2015	3/3/2016	263.63
SHERIFF OF HENRY COUNTY	KY	2015	3/3/2016	26,850.35
SHERIFF OF HOPKINS COUNTY	KY	2015	3/3/2016	2,275.62
SHERIFF OF MCCRACKEN COUNTY	KY	2015	3/3/2016	3.33
SHERIFF OF METCALFE COUNTY	KY	2015	3/3/2016	251,348.31
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	3/3/2016	58,797.75
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	3/3/2016	50,106.03
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	3/8/2016	2,756.43
SHERIFF OF MUHLENBERG COUNTY	KY	2015	3/10/2016	510.13
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	3/10/2016	14,722.27
CITY OF HOUSTON ACRES	KY	2015	3/22/2016	278.93
CITY OF LORETTO	KY	2015	3/22/2016	72.11
CITY OF SHIVELY	KY	2015	3/22/2016	39,286.52
CITY OF VINE GROVE	KY	2015	3/22/2016	833.88
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	3/24/2016	5,782.14
CITY OF PLEASUREVILLE	KY	2015	4/12/2016	145.12
CITY OF ST REGIS PARK	KY	2015	4/12/2016	261.38
TAX COLLECTOR LEBANON JUNCTION	KY	2015	4/12/2016	151.01
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	4/13/2016	4,537.83
CITY OF WOODLAWN PARK	KY	2015	5/4/2016	293.06
CITY OF WOODLAWN PARK	KY	2015	5/4/2016	293.22
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	5/19/2016	2,699.73
CITY OF WEST POINT	KY	2014	6/9/2016	4,218.39
CITY OF WEST POINT	KY	2015	6/9/2016	4,401.03
CITY OF PARIS	KY	2015	6/29/2016	3.09
SHERIFF OF BOURBON COUNTY	KY	2015	6/29/2016	25.86
SHERIFF OF MUHLENBERG COUNTY	KY	2015	7/15/2016	85.30
CITY OF JEFFERSONTOWN	KY	2014	8/22/2016	543.12
CITY OF THORNHILL	KY	2015	8/22/2016	51.01
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	9/1/2016	9,424.24
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	9/2/2016	9,351.59
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	9/6/2016	23,871.58
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	9/13/2016	28,715.12
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	10/6/2016	635.34
JEFFERSON COUNTY CLERK (Vehicle property tax)	KY	2016	10/6/2016	21.00
KENTUCKY STATE TREASURER	KY	2016	10/26/2016	9,001,285.49
SHERIFF OF JEFFERSON COUNTY	KY	2016	11/15/2016	15,193.19
SHERIFF OF TRIMBLE COUNTY	KY	2016	12/13/2016	500,000.00

Louisville Gas & Electric Company
Property Tax Payment History
For payments between 01/01/2016 and 12/31/2016

Payee Description	State	Assessment Year	Date	Amount
JEFFERSON COUNTY TREASURERS OFFICE	IN	2016	5/5/2016	2,768.74
TREASURER OF HARRISON COUNTY	IN	2016	5/5/2016	61,076.40
TREASURER OF CLARK COUNTY	IN	2016	5/5/2016	93,268.20
TREASURER OF FLOYD COUNTY	IN	2016	5/5/2016	86,724.66
				26,691,794.61

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 22

Responding Witness: Christopher M. Garrett

Q.1-22. For each taxing authority to which aggregate property tax payments exceeding $10,000 were made in 2016, please indicate the method of assessing asset value and whether the asset base includes or excludes CWIP in the determination of the assessed value used to determine the amount of taxes to be paid.

A.1-22. The Company is "Centrally Assessed" by state taxing authorities. The asset base includes CWIP in the assessed value.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to First Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated January 11, 2017

Question No. 23

Responding Witness: Christopher M. Garrett

Q.1-23. For each taxing authority to which aggregate property tax payments exceeding $10,000 were made in 2016, please indicate the time of the year when value assessments were made and when payments were due. If there are any known changes related to base year and test year assessments and changes, please describe.

A.1-23. The Company's 2016 Assessment was finalized in December 2016. Payments associated with the assessment are paid when the invoice is received from the State and Local taxing authorities. Payments were made in the fourth quarter 2016 and remaining payments are expected to be made in the first quarter 2017. There are no known changes related to the base year and the test year assessments from the filing other than normal plant additions.