VERIFICATION

The undersigned, John A. Rogness III, being duly sworn, deposes and says he is the Director Regulatory Services for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his/her information, knowledge and belief.

John A. Rogness III

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2015-00271
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John A. Rogness III, this the 11th day of November, 2015.

Judy K Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Please provide all KPC responses to requests for information from all parties and Commission Staff in this proceeding

RESPONSE

The responses will be provided through the Commission's E-Filing system..

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Application at 3 and Exhibit 2, please provide updated year-to-date energy and demand savings estimates for 2015, expressed in both kilowatt hours and as a percentage of retail sales. Please also provide updated projected estimates for the entire 2015 year, if available.

RESPONSE

Estimated gross participant energy savings YTD September 2015 at the meter are 22,872,278 kWH (.47% of YTD retail sales through September 2015). Estimated gross participant cumulative demand savings YTD September 2015 at meter is 2,828 KW.

Projected gross participant energy savings for 2015 at the meter are 32,355,956 kWH (.67% of YTD retail sales through September 2015). Projected gross participant cumulative demand savings for 2015 at meter is 3,986 KW.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Application at 3 and Exhibit 2, please provide updated year-to-date total DSM/EE costs for 2015, including total program costs, incentive payments and realized lost revenues and indicating the costs of each of these three categories. Please also provide updated projected estimates for the entire 2015 year, if available.

RESPONSE

YTD DSM Total Cost through September 2015: $3,758,591.
YTD Incentives through September 2015: $426,662.
YTD Lost Revenues through September 2015: $1,036,366.

Projected 2015 DSM Total Cost: $5,288,083.
Projected 2015 Incentives: $607,031.
Projected 2015 Lost Revenues: $1,086,072.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Please state whether the Company expects to meet its DSM spending requirement for 2015, as outlined in the Stipulation and Agreement in Case No. 2012-00578.

RESPONSE

Kentucky Power anticipates meeting its 2015 DSM spending requirement.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Application at 3, please define the term "realized lost revenues" as it is used in paragraph 5. Please also explain how these lost revenues are calculated.

RESPONSE

The realized lost revenue is the product of the number of participating customers, the average net energy savings (kWh) per customer and the net lost revenue ($/kWh). The program-to-date lost revenues are calculated in accordance with the Sunset Provision contained in the joint application filed September 27, 1995. For information concerning the Sunset Provision, please see the response to Sierra Club 1-10.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

In determining whether it has met its DSM/EE spending obligation as outlined in the Stipulation and Agreement in Case No. 2012-00578, please state whether and how KPC accounts for realized lost revenues (e.g., are realized lost revenues included in the DSM/EE spending estimate?).

RESPONSE

Only direct DSM program expense is used to calculate DSM spending for purposes of meeting the 2015 $5 million target set out in the July 2, 2013 Stipulation and Settlement Agreement approved by the Commission in Case No. 2012-00578.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Application at 3, please explain why the word "avoided" appears in quotation marks in paragraph 4.

RESPONSE

The use of quotation marks was inadvertent and no significance should be attributed to that.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Application at 3, KPC first presents 2015 year-to-date energy and demand savings estimates without avoided transmission and distribution line losses, and then provides the estimates accounting for these avoided costs in parenthesis. Please explain why the Company presents these savings estimates without avoided transmission and distribution line losses.

RESPONSE

Providing the energy and savings estimates without avoided transmission and distribution line losses presents program savings at the utility meter.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Regarding the T&D loss savings factor referenced in Exhibit 2 of the Application (pages 1 and 30 of 63):

a. Please provide the basis for using a 9% T&D loss savings factor when computing annual net energy savings.

b. Please provide the basis for using a 10% T&D loss savings factor when computing peak demand reductions.

c. Please describe how these T&D loss savings are computed as a part of total annual energy savings.

RESPONSE

a. and b. Please see attachment KPCO_R_SC_9_Attachment1.pdf.

c. The T&D loss savings are taken from the 2011 Analysis of System Losses. Please see attachment KPCO_R_SC_9_Attachment1.pdf.

WITNESS: John A Rogness

KENTUCKY POWER COMPANY

2011 Analysis of System Losses

April 2013

Prepared by:

Management Applications Consulting, Inc.
1103 Rocky Drive – Suite 201
Reading, PA 19609
Phone: (610) 670-9199 / Fax: (610) 670-9190

MANAGEMENT APPLICATIONS CONSULTING, INC.

1103 Rocky Drive • Suite 201 • Reading, PA 19609-1157 • 610/670-9199 • fax 610/670-9190 •www.manapp.com

April 17, 2013

Mr. David M. Roush
Director Regulatory Pricing & Analysis
American Electric Power
1 Riverside Plaza
Columbus, OH 43215

Mr. Mark P. Gilbert
Director Economic Forecasting
American Electric Power
212 East 6th Street
Tulsa, OK 74119

RE: 2011 LOSS ANALYSIS

Dear Messrs. Roush and Gilbert:

Transmitted herewith are the results of the 2011 Analysis of System Losses for the Kentucky Power Company's (KPCO) 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.

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 KPCO 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

Kentucky Power Company
2011 Analysis of System Losses

TABLE OF CONTENTS

Kentucky Power Company
2011 Analysis of System Losses

1.0 EXECUTIVE SUMMARY

This report presents Kentucky Power Company's (KPCO) 2011 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 KPCO. 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 sales.

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.

Table 1, below, provides the final results from Appendix A for the 2011 calendar year. Exhibits 8 and 9 of Appendix A 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.

Kentucky Power Company
2011 Analysis of System Losses

TABLE 1
Loss Factors at Sales Level, Calendar Year 2011

Voltage Level of Service	Total KPCO	Distribution Only
Demand (kW)		
Transmission[1]	1.04223	–
Subtransmission	1.06139	1.01838
Primary Lines	1.07358	1.03008
Secondary	1.10354	1.05883
Energy (kWh)		
Transmission[1]	1.03482	–
Subtransmission	1.04720	1.01197
Primary Lines	1.05535	1.01985
Secondary	1.08761	1.05102
Losses – Net System Input[2]	6.31%MWh	
	8.20%MW	
Losses – Net System Output[3]	6.73%MWh	
	8.93%MW	
Composite Loss Factors at Metered Sales Level		
	MW	MWH
Retail	1.08990	1.06774
Wholesale	1.04797	1.03845

The loss factors presented in the Delivery Only column of Table 1 are the Total KPCO loss factors divided by the transmission loss factor in order to remove these losses from each service level loss factor. For example, the secondary distribution demand loss factor of 1.05883 includes the recovery of all remaining non-transmission losses from the subtransmission, distribution substation, primary lines, line transformers, secondary conductors and services.

The net system input shown in Table 1 represents the MWh losses of 6.31% for the total KPCO load using calculated losses divided by the associated input energy to the system. The 6.73% represents the same losses using system output instead of input as a reference. The net system output reference shown in Table 1 represents MWh losses of 6.73% and MW losses of 8.93%. 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.

[1] Reflects results for 765 kV, 345 kV 161 kV, and 138 kV.
[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.

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 shown in Table 1 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 43).

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.

Kentucky Power Company
2011 Analysis of System Losses

Figure 1

MANAGEMENT APPLICATIONS CONSULTING, INC.
ELECTRIC LOSS MODEL OVERVIEW

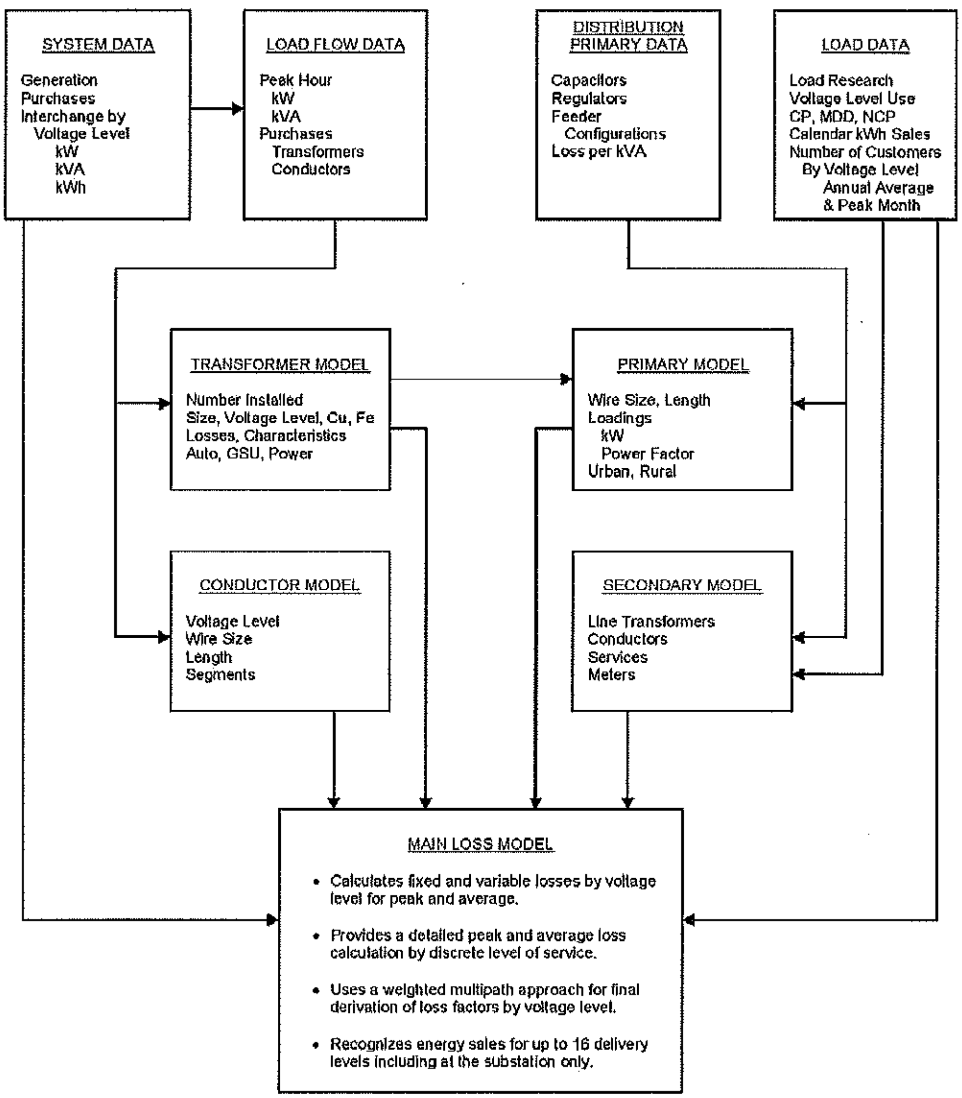
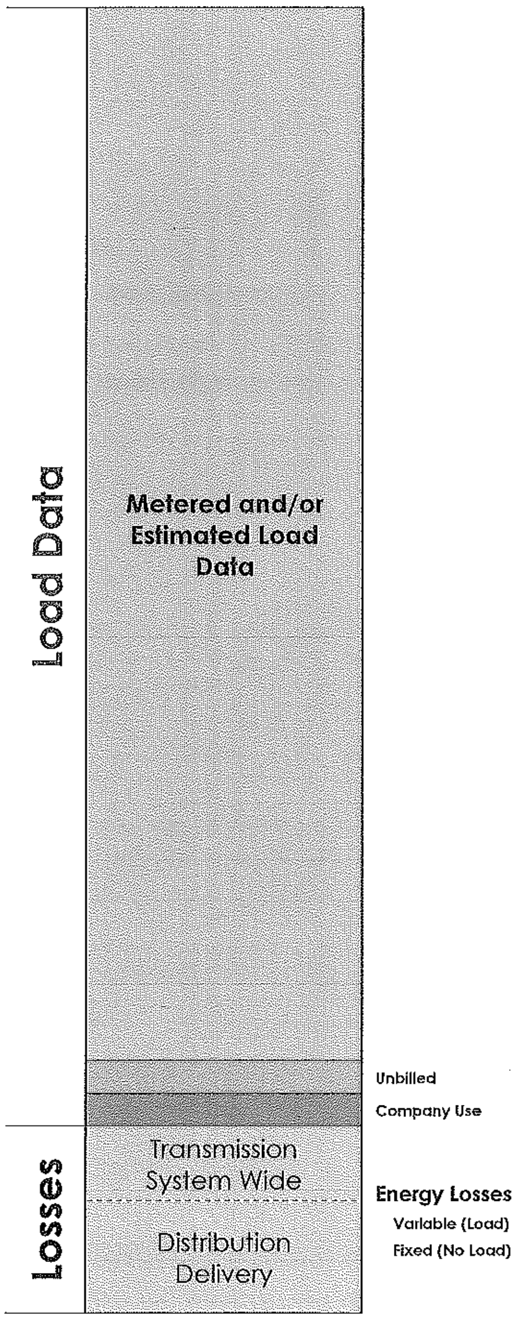


Figure 2
Generic Energy Loss Components



2.0 INTRODUCTION

This report of the 2011 Analysis of System Losses for the Kentucky Power Company 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 and high voltage transformer. Separate iron and copper losses are calculated for each transformer by identified type.

- Conductor sheet containing summary data by major voltage level as to circuit miles, loading assumptions, and kW and kWh loss calculations. Separate loss calculations for each line segment were made using the Company's power flow data by line segment and summarized by voltage level in this model.

Appendix A presents a detailed loss study result which derives the loss factors for the Company's system-wide power system. Appendix A, Exhibits 8 and 9, presents the final detailed summary results of the demand and energy losses for each major portion of the total KPCO 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

- 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 of peak condition was the primary source of equipment loadings and derivation of load losses in the high voltage loss calculations.

3. Distribution System

- Distribution Substations – Data was developed for modeling each substation as to its size and loading. Loss calculations were performed from this data to determine load and no load losses separately for each transformer.

- 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 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.

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, Transmission and Subtransmission Lines

The transmission and subtransmission 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 KPCO Power System. Specific information as to length of line, type of conductor, voltage level, peak load, maximum load, etc., were provided based on Company records and utilized as data input in the loss model.

Actual MW and MVA line loadings were based on KPCO's peak loading conditions. Calculations of line losses were performed for each line segment separately and combined by voltage levels for reporting purposes as shown in the Discussion of Results (Section 4.0) of this report. The loss calculations consisted of determining a circuit current value based on MVA line loadings and evaluating the I^2R results for each line segment.

After system coincident peak hour losses were identified for each voltage level, a separate calculation was then made to develop annual average energy losses based on a loss factor approach. Load factors were determined for each voltage level based on system and customer load information. An estimate of the Hoebel coefficient (see Appendix B) was then used to calculate energy losses for the entire period being analyzed. The results are presented in Section 4.0 of this report.

3.2.2 Transformers

The 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 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.

Standardized test data tables were used to represent no load (fixed) and full load losses for different types and sizes of transformers. This test data was incorporated into the loss model to develop relationships representing copper and iron losses for the transformer loss calculation. These results were then totaled by various groups, as identified and discussed in Section 4.0.

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.

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.

4.0 DISCUSSION OF RESULTS

A brief description of each Exhibit provided in Appendix A follows:

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 conductors by voltage levels is presented. The sum of all calculated losses by voltage level 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 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 a calculated loss factor for copper and the test year hours times no load losses.

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 substations 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.

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 KPCO 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 2011 KPCO Integrated Power System Loss Analysis

KENTUCKY POWER 2011 LOSS ANALYSIS

KENTUCKY POWER

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK	1,531	MW
ANNUAL SYSTEM INPUT	7,591,389	MWH
ANNUAL SALES OUTPUT	7,112,397	MWH
SYSTEM LOSSES @ INPUT	478,992	or 6.31%
SYSTEM LOSSES @ OUTPUT	478,992	or 6.73%
SYSTEM LOAD FACTOR	56.6%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	--- MW ---	Input	% TOTAL	--- MWH ---	Input	% TOTAL
TRANS	765,345	52.9		42.15%	211,400		44.13%
	161,138		3.45%			2.78%	
SUBTRANS	69,46,34	20.8		16.54%	68,753		14.35%
			1.36%			0.91%	
PRIMARY	34,12,1	22.2		17.67%	57,725		12.05%
			1.45%			0.76%	
SECONDARY	120/240,to,477	29.7		23.64%	141,114		29.46%
			1.94%			1.86%	
TOTAL		125.5		100.00%	478,992		100.00%
			8.20%			6.31%	

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND (Peak) d	1/d	ENERGY (Annual) e	1/e
TOT TRANS	765,345 161,138	1.04223	0.95948	1.03482	0.96636
SUBTRAN	69,46,34	1.06139	0.94216	1.04720	0.95492
PRIMARY	34,12,1	1.07358	0.93146	1.05535	0.94755
SECONDARY	120/240,to,477	1.10354	0.90617	1.08761	0.91944

KENTUCKY POWER 2011 LOSS ANALYSIS

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 ---	765 KV OR GREATER								
TIE LINES		0.0	0.00%	0.000	0.000	0.000	0	0	0
BULK TRANS		257.5	0.00%	11.777	2.844	14.621	71,988	24,912	96,900
SUBTOT		257.5		11.777	2.844	14.621	71,988	24,912	96,900
--- TRANS ---	138 KV TO 765.00 KV								
TIE LINES		0	0.00%	0.000	0.000	0.000	0	0	0
TRANS1	161 KV	56.5	0.00%	4.361	0.040	4.402	14,202	352	14,553
TRANS2	138 KV	338.0	0.00%	27.416	0.166	27.582	80,948	1,458	82,406
SUBTOT		394.6		31.777	0.207	31.984	95,150	1,810	96,960
--- SUBTRANS ---	35 KV TO 138 KV								
TIE LINES		0	0.00%	0.000	0.000	0.000	0	0	0
SUBTRANS1	69 KV	425.0	0.00%	13.669	0.000	13.669	40,500	0	40,500
SUBTRANS2	46 KV	167.3	0.00%	3.794	0.000	3.794	11,243	0	11,243
SUBTRANS3	35 KV	3.2	0.00%	0.010	0.006	0.016	30	54	83
SUBTOT		595.4		17.473	0.006	17.479	51,772	54	51,826
PRIMARY LINES		8,180		13.136	0.000	13.136	25,107	0	25,107
SECONDARY LINES		2,367		4.736	0.000	4.736	9,354	0	9,354
SERVICES		3,147		5.622	0.364	5.985	11,969	3,184	15,153
TOTAL		14,941		84.521	3.420	87.941	265,340	29,960	295,300

KENTUCKY POWER 2011 LOSS ANALYSIS

SUMMARY OF TRANSFORMER INFORMATION

DESCRIPTION		KV VOLTAGE	CAPACITY MVA	NUMBER TRANSFMR	AVERAGE SIZE	LOADING %	MVA LOAD	MW LOSSES LOAD	MW LOSSES NO LOAD	MW LOSSES TOTAL	MWH LOSSES LOAD	MWH LOSSES NO LOAD	MWH LOSSES TOTAL
BULK STEP-UP		765	1,500.0	3	500.0	3.39%	51	0.010	0.662	0.672	30	5,795	5,824
BULK - BULK			0.0	0	0.0	0.00%	0	0	0.000	0.000	0	0	0
BULK - TRANS1		161	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		161	950.0	1	950.0	85.71%	814	1.599	0.448	2.047	4,433	3,672	8,105
TRANS1 - TRANS2		138	735.0	4	183.8	77.68%	571	0.589	0.606	1.195	1,745	5,313	7,058
TRANS1-SUBTRANS1		69	54.0	1	54.0	116.02%	63	0.131	0.056	0.187	716	487	1,204
TRANS1-SUBTRANS2		46	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	354.0	3	118.0	87.60%	310	1.057	0.328	1.385	3,004	2,743	5,747
TRANS2-SUBTRANS1		69	849.0	15	56.6	95.50%	811	1.262	0.888	2.150	8,326	7,781	16,107
TRANS2-SUBTRANS2		46	75.0	2	37.5	97.14%	73	0.286	0.081	0.367	815	708	1,524
TRANS2-SUBTRANS3		35	57.0	2	28.5	24.35%	14	0.021	0.062	0.083	42	544	586
SUBTRAN1 STEP-UP		69	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN2 STEP-UP		46	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		46	24.0	2	12.0	82.91%	20	0.073	0.031	0.104	221	275	496
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 -	161	33	24.0	2	12.0	88.25%	21	0.084	0.031	0.116	175	275	451
TRANS1 -	161	12	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS1 -	161	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
TRANS2 -	138	33	285.0	12	23.8	66.92%	191	0.534	0.332	0.865	1,113	2,906	4,019
TRANS2 -	138	12	67.0	4	16.8	80.87%	54	0.179	0.083	0.261	373	724	1,097
TRANS2 -	138	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN1-	69	33	209.0	12	17.4	82.33%	172	0.558	0.257	0.816	1,165	2,252	3,417
SUBTRAN1-	69	12	620.5	54	11.5	76.80%	477	1.786	0.825	2.611	3,725	7,230	10,955
SUBTRAN1-	69	1	15.0	2	7.5	10.79%	2	0.001	0.024	0.025	2	209	211
SUBTRAN2-	46	33	87.0	4	21.8	80.83%	70	0.207	0.102	0.309	432	893	1,325
SUBTRAN2-	46	12	139.3	13	10.7	63.91%	89	0.335	0.191	0.526	699	1,676	2,375
SUBTRAN2-	46	1	1.0	1	1.0	23.98%	0	0.000	0.002	0.002	1	18	18
SUBTRAN3-	35	33	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
SUBTRAN3-	35	12	5.0	1	5.0	116.20%	6	0.042	0.009	0.051	88	77	165
SUBTRAN3-	35	1	0.0	0	0.0	0.00%	0	0.000	0.000	0.000	0	0	0
PRIMARY - PRIMARY			21.3	4	5.3	54.60%	12	0.042	0.037	0.079	88	321	408
LINE TRANSFRMR			3,179.4	98,137	32.4	33.22%	1,056	4.227	10.149	14.376	6,931	88,902	95,833
TOTAL			9,251	98,279				13.024	15.204	28.228	34,123	132,801	166,925

KENTUCKY POWER 2011 LOSS ANALYSIS

SUMMARY OF LOSSES DIAGRAM - DEMAND MODEL - SYSTEM PEAK 1530.76 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 11.777 MW
NOLD LOSS 2.844 MW

BULK STEP UP
LOADING 3.39%
NO LOAD 0.662 MW
LOAD 0.010 MW
AVG SIZE 500 MVA
NUMBER 3

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 77.68%
NO LOAD 0.606 MW
LOAD 0.589 MW
AVG SIZE 183.75 MVA
NUMBER 4

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 85.71%
NOLOAD1&2 0.776 MW
LOAD 1&2 2.656 MW
AVSIZ TR1SU 950.0 MVA
NUMBER 1

TRANS1 161.0 KV
LOADING 0.00%
LOAD LOSS 4.361 MW
NOLD LOSS 0.040 MW

TRANS2 138.0 KV
LOADING 0.00%
LOAD LOSS 27.416 MW
NOLD LOSS 0.166 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 95.50%
NO LOAD 0.944 MW
LOAD 1.393 MW
AVSIZ TR2 56.6 MVA
NUMBER 16

SUBTR1&2-SUBTRANS2&3
LOADING 0.00%
NO LOAD 0.031 MW
LOAD 0.073 MW
AVG SIZE 0 MVA
NUMBER 2

TRANS1&2- SUBTRANS2
LDNG TR2-ST 97.14%
NO LOAD 0.081 MW
LOAD 0.286 MW
AVSIZ TR2-ST 37.50 MVA
NUMBER 2

TRANS1&2-SUBTRANS3
LDNG TR2-ST2 24.35%
NO LOAD 0.06
LOAD 0.02
AVSIZ TR2-ST2 28.50
NUMBER 2

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 13.669 MW
NOLD LOSS 0.000 MW

SUBTRANS2 46 KV
LOADING 0.00%
LOAD LOSS 3.794 MW
NOLD LOSS 0.000 MW

SUBTRANS2 35 KV
LOADING 0.00%
LOAD LOSS 0.010 MW
NOLD LOSS 0.006 MW

SUBTRANS CUST
SUBS - MW 0.000
MVA 0.000
LINES- MW
MVA

TO DISTRIBUTION SYSTEM
TOTAL 1081.7 MVA 1060.1 MW

TRANS1 21.2 MVA
1.96%
161 KV

TRANS2 244.9 MVA
22.64%
138 KV

SUBTRANS1 650.3 MVA
60.11%
69 KV

SUBTRANS2 159.5 MVA
14.75%
46 KV

SUBTRANS3 5.8 MVA
0.54%
35 KV

KENTUCKY POWER 2011 LOSS ANALYSIS

FROM HIGH VOLTAGE SYSTEM

TOTAL 1,082 MVA 1,060 MW

TRANS1 21.2 MVA 1.96% 161 KV	TRANS2 244.9 MVA 22.64% 138 KV	SUBTRANS1 650.3 MVA 60.11% 69 KV	SUBTRANS2 159.5 MVA 14.75% 46 KV	SUBTRANS3 5.8 MVA 0.54% 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	21	0	0	191	54	0	172	477	2	70	89	0	0	6	0
% SYS TOT	1.96%	0.00%	0.00%	17.63%	5.01%	0.00%	15.91%	44.06%	0.15%	6.50%	8.23%	0.02%	0.00%	0.54%	0.00%
NOLD LOSS	0.031	0.000	0.000	0.332	0.083	0.000	0.257	0.825	0.024	0.102	0.191	0.002	0.000	0.009	0.000
LOAD LOSS	0.084	0.000	0.000	0.534	0.179	0.000	0.558	1.786	0.001	0.207	0.335	0.000	0.000	0.042	0.000
AVG SIZE	12.0	0.0	0.0	23.8	16.8	0.0	17.4	11.5	7.5	21.8	10.7	1.0	0.0	5.0	0.0
NUMBER	2	0	0	12	4	0	12	54	2	4	13	1	0	1	0
DIVERSITY RATIO	1.000	0.000	0.000	1.000	1.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	0.000

PRIMARY LINES
LOADING 1054.312 MW
@ SYS PF 1075.828 MVA
LOAD LOSS 13.136 MW
NOLD LOSS 0.000 MW
TOT LOSS 13.136 MW

PRIM/PRIM TRANSF
LOADING 11.603 MW
NOLD LOSS 0.037 MW
LOAD LOSS 0.042 MW
AVG SIZE 5.31
NUMBER 4

PRIM CUST LOADS
NO LINES 0.000 MW
CUST SUB 0.000 MVA
NO LINES 0.000 MW
CO. SUB 0.000 MVA
PRIM WITH 74.700 MW
LINES 81.196 MVA

LINE TRANSFORMERS
LOADING 966.397 MW MVA 1070.622
NOLD LOSS 10.149 MW
LOAD LOSS 4.227 MW
AVG SIZE 32.4 KVA
NUMBER 98137

SECONDARY LINES
LOAD 383.057 MW
LOAD LOSS 4.736 MW
NOLD LOSS 0.000 MW
TOT LOSS 4.736 MW

NO SECONDARY LINES
LOAD 568.964 MW

SERVICES
LOAD 947.285 MW
LOAD LOSS 5.622 MW
NOLD LOSS 0.364 MW
TOT LOSS 5.985 MW

CUSTOMER SECONDARY LOAD
941.300 MW

KENTUCKY POWER 2011 LOSS ANALYSIS

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	49.9	3.51	11.79	15.29	1.441882	1.441882	244,789	30,707	72,018	102,725	1.7230845	1.7230845
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	798.0	0.49	5.96	6.45	1.008147	1.008147	4,562,176	4,024	18,634	22,658	1.0049913	1.0049913
5 TRANS2TR1 SD	559.5	0.61	0.59	1.20	1.002141	1.010305	2,744,683	5,313	1,745	7,058	1.0025780	1.0075822
6 TRANS2BLK SD	0.0	0.00	0.00	0.00	0.000000	0.000000	0	0	0	0	0.0000000	0.0000000
7 TRANS2 LINES	1,213.4	0.49	28.47	28.97	1.024457	1.029325	5,920,714	4,201	83,952	88,153	1.0151140	1.0186820
TOTAL TRAN	1,305.0	5.09	46.81	51.90	1.041421	1.041421	6,283,446	44,244	176,349	220,594	1.0363845	1.0363845
8 STR1BLK SD												
9 STR1T1 SD	61.4	0.06	0.13	0.19	1.003049	1.044596	301,204	487	716	1,204	1.0040123	1.0405428
10 SRT1T2 SD	794.6	0.89	1.26	2.15	1.002713	1.044247	3,897,990	7,781	8,326	16,107	1.0041494	1.0406848
11 SUBTRANS1 LINES	981.0	0.00	13.67	13.67	1.014130	1.056136	5,199,194	0	40,500	40,500	1.0078508	1.0445209
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	71.4	0.08	0.29	0.37	1.005164	1.046799	350,260	708	815	1,524	1.0043692	1.0409126
14 STR2S1 SD	19.5	0.03	0.07	0.10	1.005385	1.061823	95,659	275	221	496	1.0052158	1.0499690
15 SUBTRANS2 LINES	160.9	0.00	3.79	3.79	1.024152	1.066573	695,919	0	11,243	11,243	1.0164204	1.053402
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	13.6	0.06	0.02	0.08	1.006146	1.047821	66,716	544	42	586	1.0088600	1.0455668
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	13.6	0.01	0.01	0.02	1.001187	1.042657	66,716	54	30	83	1.0012492	1.0376792
21 SUBTRANS TOTAL	1,150.0	1.12	19.25	20.37	1.018033	1.060201	5,811,708	9,850	61,893	71,743	1.0124989	1.049338
DISTRIBUTION SUBST												
TRANS1	20.8	0.03	0.08	0.12	1.005598	1.047251	83,968	275	175	451	1.0053984	1.0419793
TRANS2	240.0	0.41	0.71	1.13	1.004717	1.046333	970,949	3,630	1,486	5,116	1.0052971	1.0418743
SUBTR1	637.3	1.11	2.35	3.45	1.005446	1.061888	2,577,918	9,691	4,892	14,583	1.0056891	1.0504633
SUBTR2	156.4	0.30	0.54	0.84	1.005387	1.072319	632,521	2,587	1,132	3,718	1.0059134	1.0596314
SUBTR3	5.7	0.01	0.04	0.05	1.009001	1.052042	23,033	77	88	165	1.0072010	1.0451515
WEIGHTED AVERAGE	1,060.1	1.86	3.73	5.58	1.005294	1.059565	4,288,389	16,260	7,773	24,033	1.0056358	1.0496762
PRIMARY INTRCHNGE	0.0				0.000000		0				0.0000000	
PRIMARY LINES	1,054.3	0.00	13.18	13.18	1.012658	1.072977	4,264,267	0	25,194	25,194	1.0059434	1.0559148
LINE TRANSF	966.4	10.15	4.23	14.38	1.015101	1.089180	3,722,774	88,902	6,931	95,833	1.0264225	1.0838147
SECONDARY	952.0	0.00	4.74	4.74	1.004999	1.094625	3,626,941	0	9,354	9,354	1.0025858	1.0866172
SERVICES	947.3	0.36	5.62	5.99	1.006358	1.101585	3,617,587	3,184	11,969	15,153	1.0042063	1.0911879
		==========	==========	==========				==========	==========	==========		
TOTAL SYSTEM		18.59	97.55	116.13				162,441	299,463	461,904		

KENTUCKY POWER 2011 LOSS ANALYSIS

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	73.0	3.0	76.0	1.04142	0.96023
TOTAL TRANS	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS	316.3	19.0	335.3	1.06020	0.94322
PRIM SUBS	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	74.7	5.5	80.2	1.07298	0.93199
SECONDARY	941.3	95.6	1,036.9	1.10158	0.90778
TOTALS	1,405.3	123.1	1,528.4		

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	526,918	19,172	546,090	1.03638	0.96489
TOTAL TRANS	0	0	0	0.00000	0.00000
SUBTRANS	2,466,746	121,705	2,588,451	1.04934	0.95298
PRIM SUBS	0	0	0	0.00000	0.00000
PRIM LINES	516,299	28,869	545,168	1.05591	0.94705
SECONDARY	3,602,434	328,498	3,930,932	1.09119	0.91643
TOTALS	7,112,397	498,243	7,610,640		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	76.02	546,090
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	335.34	2,588,451
PRIM SUBS	0.00	0
PRIM LINES	80.15	545,168
SECONDARY	1,036.92	3,930,932
SUBTOTAL	1,528.44	7,610,640
ACTUAL ENERGY	1,530.76	7,591,389
MISSMATCH	(2.32)	19,251
% MISSMATCH	-0.15%	0.25%

KENTUCKY POWER 2011 LOSS ANALYSIS

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	73.0	0.0	3.1	76.1	1.04223	0.95948
TOTAL TRANS	0.0	0.0	0.0	0.0	0.00000	0.00000
SUBTRANS	316.3	0.0	19.4	335.7	1.06139	0.94216
PRIM SUBS	0.0	0.0	0.0	0.0	0.00000	0.00000
PRIM LINES	74.7	0.0	5.5	80.2	1.07358	0.93146
SECONDARY	941.3	0.0	97.5	1,038.8	1.10354	0.90617
			125.5			
TOTALS	1,405.3	0.0	125.5	1,530.8		

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	526,918	0	18,345	545,263	1.03482	0.96636
TOTAL TRANS	0	0	0	0	0.00000	0.00000
SUBTRANS	2,466,746	0	116,440	2,583,186	1.04720	0.95492
PRIM SUBS	0	0	0	0	0.00000	0.00000
PRIM LINES	516,299	0	28,579	544,878	1.05535	0.94755
SECONDARY	3,602,434	0	315,620	3,918,054	1.08761	0.91944
			478,983			
TOTALS	7,112,397	0	478,992	7,591,380		

ESTIMATED VALUES AT GENERATION

LOSS FACTOR AT VOLTAGE LEVEL	MW	MWH
BULK LINES	0.00	0
TRANS SUBS	0.00	0
TRANS LINES	76.08	545,263
SUBTRANS SUBS	0.00	0
SUBTRANS LINES	335.72	2,583,186
PRIM SUBS	0.00	0
PRIM LINES	80.20	544,878
SECONDARY	1,038.77	3,918,054
	1,530.76	7,591,380
ACTUAL ENERGY	1,530.76	7,591,389
MISSMATCH	0.00	(9)
% MISSMATCH	0.00%	0.00%

KENTUCKY POWER 2011 LOSS ANALYSIS

Adjusted Losses and Loss Factors by Facility EXHIBIT 8

Unadjusted Losses by Segment

	MW	Unadjusted	MWH	Unadjusted
Service Drop Losses	5.99	6.94	15,153	18,400
Secondary Losses	4.74	5.49	9,354	11,359
Line Transformer Losses	14.38	16.67	95,833	116,370
Primary Line Losses	13.18	15.28	25,194	30,594
Distribution Substation Losses	5.58	6.47	24,033	29,183
Subtransmission Losses	20.37	20.37	71,743	71,743
Transmission System Losses	51.90	51.90	220,594	220,594
Total	116.13	123.14	461,904	498,243

Mismatch Allocation by Segment

	MW	MWH	Note adjusting
Service Drop Losses	-0.13	632	632
Secondary Losses	-0.10	390	390
Line Transformer Losses	-0.31	3,994	3,994
Primary Line Losses	-0.29	1,050	1,050
Distribution Substation Losses	-0.12	1,002	1,002
Subtransmission Losses	-0.38	2,990	2,990
Transmission System Losses	-0.98	9,194	9,194
Total	-2.32	19,251	19,251
			19,251

Adjusted Losses by Segment

	MW	% of Total	MWH	% of Total
Service Drop Losses	7.07	5.6%	17,769	3.7%
Secondary Losses	5.60	4.5%	10,969	2.3%
Line Transformer Losses	16.99	13.5%	112,376	23.5%
Primary Line Losses	15.57	12.4%	29,544	6.2%
Distribution Substation Losses	6.60	5.3%	28,182	5.9%
Subtransmission Losses	20.75	16.5%	68,753	14.4%
Transmission System Losses	52.88	42.2%	211,400	44.1%
Total	125.46	100.0%	478,992	100.0%

Loss Factors by Segment	**MW**	**MWH**
Retail Sales from Service Drops	941.30	3,602,434
Adjusted Service Drop Losses	7.07	17,769
Input to Service Drops	948.37	3,620,203
Service Drop Loss Factor	**1.00751**	**1.00493**
Output from Secondary	948.37	3,620,203
Adjusted Secondary Losses	5.60	10,969
Input to Secondary	953.97	3,631,172
Secondary Conductor Loss Factor	**1.00590**	**1.00303**
Output from Line Transformers	953.97	3,631,172
Adjusted Line Transformer Losses	16.99	112,376
Input to Line Transformers	970.95	3,743,548
Line Transformer Loss Factor	**1.01781**	**1.03095**
Secondary Composite	1.03150	1.03917
Retail Sales from Primary	74.70	516,299
Req. Whls Sales from Primary	0.00	0
Input to Line Transformers	970.95	3,743,548
Output from Primary Lines	1045.65	4,259,847
Adjusted Primary Line Losses	15.57	29,544
Input to Primary Lines	1061.23	4,289,391
Primary Line Loss Factor	**1.01489**	**1.00694**
Out TO PR from Distribution Substations	1061.23	4,289,391
Req. Whls Sales from Substations	0.00	0
Retail Sales from Substations	0.00	0
TotalOutput from Distribution Substations	1061.23	4,289,391
Adjusted Distribution Substation Losses	6.60	28,182
Input to Distribution Substations	1067.82	4,317,572
Distribution Substation Loss Factor	**1.00622**	**1.00657**
Retail Sales at from SubTransmission	310.10	2,438,725
Req. Whls Sales from SubTransmission	6.20	28,021
Input to Distribution Substations	799.30	3,233,472
Output from SubTransmission	1129.25	5,742,955
Adjusted SubTransmission System Losses	20.75	68,753
Input to SubTransmission	1150.00	5,811,708
SubTransmission Loss Factor	**1.01838**	**1.01197**
OUT DISTR SUBS	260.77	1,054,917
Retail Sales at from Transmission	58.50	459,332
Req. Whls Sales from Transmission	14.50	67,586
Input Subtransmission	918.35	4,490,212
Output from Transmission	1252.12	6,072,046
Adjusted Transmission System Losses	52.88	211,400
Input to Transmission	1305.00	6,283,446
Transmission Loss Factor	**1.04223**	**1.03482**

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		941.30		941.3				
3	LOSSES			7.1	7.1				
4	INPUT				948.4				
5	**EXPANSION FACTOR**	**1.00751**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			5.6	5.6				
9	INPUT				954.0				
10	**EXPANSION FACTOR**	**1.00590**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			17.0	17.0				
14	INPUT				971.0				
15	**EXPANSION FACTOR**	**1.01781**							
16	**PRIMARY**								
17	SECONDARY				971.0				
18	SALES		74.70			74.7			
19	LOSSES			15.6	14.5	1.1			
20	INPUT								
21	**EXPANSION FACTOR**	**1.01489**							
22	**SUBSTATION**								
23	PRIMARY				985.4	75.8			
24	SALES		0.0						
25	LOSSES			6.6	6.1	0.5			
26	INPUT				991.5	76.3			
27	**EXPANSION FACTOR**	**1.00622**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS				724.3	75.0			
30	SALES		316.30					316.3	
31	LOSSES			20.8	13.3	1.4		5.8	
32	INPUT				737.6	76.4		322.1	
33	**EXPANSION FACTOR**	**1.01838**							
34	**TRANSMISSION**								
35	SUBTRANSMISSION				523.7	54.2		322.1	
36	DISTRIBUTION SUBS				259.5	1.3			
37	SALES		73.00						73.0
38	LOSSES			52.9	33.1	2.3		13.6	3.1
39	INPUT				817.6	57.9		335.7	76.1
40	**EXPANSION FACTOR**	**1.04223**							
41	**TOTALS** LOSSES	CALCULATED		125.5	96.6	5.3		19.4	3.1
		SCALED		125.5	97.5	5.5		19.4	3.1
42	% OF TOTAL			100%	77.69%	4.38%		15.48%	2.46%
43	SALES		1,405.3		941.3	74.7		316.3	73.0
44	% OF TOTAL		100.00%		66.98%	5.32%		22.51%	5.19%
45	INPUT		1,530.8		1,038.8	80.2		335.7	76.1
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.10354**	**1.07358**	**NA**	**1.06139**	**1.04223**

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		3,602,434		3,602,434				
3	LOSSES			17,769	17,769				
4	INPUT				3,620,203				
5	**EXPANSION FACTOR**	**1.00493**							
6	**SECONDARY**								
7	SALES								
8	LOSSES			10,969	10,969				
9	INPUT				3,631,172				
10	**EXPANSION FACTOR**	**1.00303**							
11	**LINE TRANSFORMER**								
12	SALES								
13	LOSSES			112,376	112,376				
14	INPUT				3,743,548				
15	**EXPANSION FACTOR**	**1.03095**							
16	**PRIMARY**								
17	SECONDARY				3,743,548				
18	SALES		516,299.000			516,299			
19	LOSSES			29,544	25,963	3,581			
20	INPUT								
21	**EXPANSION FACTOR**	**1.00694**							
22	**SUBSTATION**								
23	PRIMARY				3,769,511	519,880			
24	SALES		0						
25	LOSSES			28,182	24,766	3,416			
26	INPUT				3,794,277	523,295			
27	**EXPANSION FACTOR**	**1.00657**							
28	**SUB-TRANSMISSION**								
29	DISTRIBUTION SUBS				3,173,472	60,000			
30	SALES		2,466,746					2,466,746	
31	LOSSES			68,753	37,992	718		29,531	
32	INPUT				3,211,464	60,718		2,496,277	
33	**EXPANSION FACTOR**	**1.01197**							
34	**TRANSMISSION**								
35	SUBTRANSMISSION				1,926,879	60,718		2,496,277	
36	DISTRIBUTION SUBS				591,621	463,295			
37	SALES		526,918						526,918
38	LOSSES			211,400	87,682	16,130		86,908	18,345
39	INPUT				2,606,182	479,425		2,583,186	545,263
40	**EXPANSION FACTOR**	**1.03482**							
41	**TOTALS** LOSSES	Calculated		478,992	317,517	23,844		116,440	18,345
		Scaled		478,983	315,620	28,579		116,440	18,345
42	% OF TOTAL			100%	66.29%	4.98%			3.83%
43	SALES		7,112,397		3,602,434	516,299		2,466,746	526,918
44	% OF TOTAL		100.00%		50.65%	7.26%		34.68%	7.41%
45	INPUT		7,591,380		3,918,054	544,878		2,583,186	545,263
46	**CUMMULATIVE EXPANSION LOSS FACTORS** (from meter to system input)				**1.08761**	**1.05535**	**NA**	**1.04720**	**1.03482**

Appendix B

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:

$$(3)\ F_{LS}\ .\ H^*F_{LD}^2 + (1\text{-}H)^*F_{LD}$$

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:

$$(5)\ A_{LS}\ .\ P_{LS}\ ^*\ [H^*F_{LD}^2 + (1\text{-}H)^*F_{LD}]$$

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.

Kentucky Power Company

REQUEST

Regarding the savings and lost revenue calculations discussed in Exhibit 2 of the Application (pages 1 and 30 of 63):

a. Please provide the referenced Sunset Provision.

b. Please explain the term "initial values" as it is used in the following sentence on p. 30 of 63: "The individual DSM lost revenue, efficiency incentive and maximizing incentives as of June 30, 1997 are calculated based on the initial values from Exhibit E in the joint application, filed September 27, 1995."

c. Please provide the Exhibit E referenced in the sentence quoted above in subpart (b).

RESPONSE

a. Per Kentucky Power's September 27, 1995 DSM filing in Case No. 95-427, the Company stated on Page 93 of the filing:

> If, in fact, KPCo files a base rate case and begins collecting new base rates that recognize the revenues lost as a result of DSM programs, then the lost kWh associated with these DSM programs would theoretically be reflected in the billing determinants used to establish those new base rates. Under those circumstances, continued surcharge recovery of net lost revenues would result in a double collection. Therefore, coincident with the implementation of new base rates, net lost revenues for the existing participants of KPCo's DSM programs will cease to be collected through the surcharge. However, if during the three-year period, there is no change in Kentucky Power's base rates, the Collaborative has agreed to a sunset provision with respect to net lost revenues. The sunset provision provides that the first year's net lost revenues will no longer be recovered in Year 4 absent a base rate case. The second year's net lost revenues would cease to be recovered in Year 5 absent a base rate case, and so forth.

b-c. The phrase "initial values" when discussing Exhibit E represents the first values the Company used in the Company's initial DSM filing in Case No. 95-427. Please see KPCo_R_SC_10_Attachment1.pdf for a copy of Exhibit E from Case No. 95-427.

WITNESS: John A Rogness

EXHIBIT E

KENTUCKY POWER COMPANY
DERIVATION FOR THREE-YEAR DSM EXPERIMENT
COLLABORATIVE AGREED UPON INITIAL VALUES

PROGRAM DESCRIPTIONS	EFFICIENCY INCENTIVE $/PARTICIPANT *	MAXIMIZING INCENTIVE ##	NET LOST REVENUE/YEAR KWH/PARTICIPANT **	NET LOST REVENUES $/KWH #
RESIDENTIAL				
Energy Fitness	78.22	N/A	2,690	0.03114
Targeted Energy Efficiency				
- All Electric	0.00	SEE ##	5,570	0.03113
- Non All Electric	9.71	N/A	680	0.03124
Compact Fluorescent Bulb	1.58	N/A	62	0.03097
High-Efficiency Heat Pump				
- Resistance Heat	19.73	N/A	2,275	0.03112
- Non Resistance Heat	16.69	N/A	813	0.03114
High-Efficiency Heat Pump - Mobile Home	38.86	N/A	2,160	0.03111
Mobile Home New Construction	N/A	SEE ##	N/A	N/A
Commercial				
SMART Audit -- Class 1	N/A	SEE ##	N/A	N/A
SMART Audit -- Class 2	N/A	SEE ##	N/A	N/A
SMART Financing -- Existing Building	506.34	N/A	22,000	0.04267
SMART Financing -- New Building	50.33	N/A	30,600	0.04267
Industrial				
SMART Audit -- Class 1	N/A	SEE ##	N/A	N/A
SMART Audit -- Class 2	N/A	SEE ##	N/A	N/A
SMART Financing -- General	178.65	N/A	28,200	0.04108
SMART Financing -- Compressed Air System	4,850.21	N/A	164,800	0.03271

* Efficiency incentive defined as 15% of estimated net savings based on the TRC test.

** These annual kWh per participant values reflect (exclude) the estimated effects of freeriders in each program.

\# Net lost revenues per kWh where net revenues are defined as gross revenues minus variable costs based on the company's current rates in effect.

\## The maximizing incentive is defined as 5% of actual program costs.

Kentucky Power Company

REQUEST

Please provide the projected incremental energy savings for each of the years 2016 through 2018, expressed in both kilowatt hours and as a percentage of retail sales, for each program in KPC's DSM plan and for the plan as a whole

RESPONSE

Please see KPCO_R_SC_11_Attachment1.xls for this response.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

For each existing program that KPC proposes to continue (either in existing or modified form), please provide the energy savings projections for 2016 and 2017, expressed in both kilowatt hours and as a percentage of retail sales, that KPC made at the time it applied for approval in Case No. 2014-00271.

RESPONSE

Energy savings projections for 2016 and 2017 were not available when the Company was seeking approval in Case No. 2014-00271. The requested information was developed following the receipt of the July 30, 2015 Market Potential Assessment prepared for Kentucky Power by Applied Energy Group, Inc. *See e.g.*, the Company's October 10, 2014 response to SC 1-6 in Case No. 2014-00271.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Please provide the projected incremental demand savings for each of the years 2016 through 2018, for each program in KPC's DSM plan and for the plan as a whole.

RESPONSE

Please see KPCO_R_SC_13_Attachment1.xls for this response.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

For each existing program that KPC proposes to continue (either in existing or modified form), please provide the demand savings projections for 2016 and 2017 that KPC made at the time it applied for approval in Case No. 2014-00271.

RESPONSE

Demand savings projections for 2016 and 2017 were not available when the Company was seeking approval in Case No. 2014-00271. The requested information was developed following the receipt of the July 30, 2015 Market Potential Assessment prepared for Kentucky Power by Applied Energy Group, Inc. *See e.g.*, the Company's October 10, 2014 response to SC 1-7 in Case No. 2014-00271.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Please provide the provide the participant forecast for each program the Company proposes to offer (both existing/modified and new) for each of the years 2016 through 2018, for each program in KPC's DSM plan and for the plan as a whole.

RESPONSE

Please see KPCO_R_SC_15_Attachment1.xls for this response.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

For existing programs that KPC proposes to continue (either in existing or modified form), please provide the participant forecast for each of the years 2016 and 2017 that KPC made at the time it applied for approval in Case No. 2014-00271.

RESPONSE

Participant forecasts for 2016 and 2017 were not available when the Company was seeking approval in Case No. 2014-00271. The requested information was developed following the receipt of the July 30, 2015 Market Potential Assessment prepared for Kentucky Power by Applied Energy Group, Inc. *See e.g.*, the Company's October 10, 2014 response to SC 1-5 in Case No. 2014-00271.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Please explain how the Company plans to evaluate the School Energy Manager Program and what criteria will be used

RESPONSE

The program will be included with the process evaluation for the DSM portfolio expected to begin Fall 2016. In addition to the process evaluation, this program will include an impact evaluation to determine savings and performance.

KPCO plans to perform both process and impact evaluations on the School Energy Manager Program. The primary objective of a process evaluation is to help program designers and managers structure their programs to achieve cost-effective savings while maintaining high levels of customer satisfaction. To achieve these goals, the process evaluation gathers information from a variety of sources including program staff, market actors and program participants. An impact evaluation verifies measure installations, identifies key energy assumptions and provides the research necessary to calculate defensible and accurate savings attributable to the program.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

For each of the Companies' existing DSM programs that it seeks to continue (either in existing or modified form), please provide the Companies' most recent EM&V report or assessment.

RESPONSE

The August 10, 2015 "Kentucky Power Company (KPCo) Demand Side Management Program Plan" attached as Exhibit 6 to the Company's application, represents the most recent assessment of existing programs with the exception of the Community Outreach and Energy Education for Students programs. Please see KPCO_R_SC_18_Attachment1.pdf for the "Kentucky Power Company 2012-2013 Demand Side Management Portfolio Evaluation – Process, Market and Impact Evaluations – July 2014," submitted with Case 2014-00271 as Exhibit 2 for the most recent Community Outreach and Student Energy Education program assessments.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

For each of the following programs, please provide the expected change in demand and energy savings for each program from 2015 to 2016:

a. Residential Efficient Products

b. Appliance Recycling Program

c. Targeted Energy Efficiency Program

d. Energy Education for Students

e. Community Outreach CFL Program

RESPONSE

Please see KPCO_R_SC_19_Attachment1.xlsx for the requested information.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Application at page 14, please explain why the New Construction Program is not available to industrial customers and builders.

RESPONSE

Expected customer participation levels, attendant program costs were selected at the Mid Scenario level and the DSM surcharge was designed for the commercial customer class only. The Company's selection of the Mid Scenario participation level reflects the fact that industrial customers have chosen to opt out of participating in the Company's DSM programs. Please also see the Company's response to KPSC 1-30.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Please explain what, if any, DSM programs would be available to KPC's industrial customers if the Company's proposed plan is approved. If none, please explain why.

RESPONSE

The practical effect of KRS 278.285(3), which permits industrial customers to "opt-out" of industrial DSM programs under certain circumstances, has been to eliminate or significantly restrict its industrial customers' interest in Company-sponsored DSM programs. Moreover, even in the absence of "opt-out" provisions such as KRS 278.285(3), participation in DSM programs is voluntary. Kentucky Power's industrial customers have not demonstrated an interest in participating in, or having the Company establish pursuant to KRS 278.285, industrial DSM programs.

There are no DSM programs available to industrial customers in the Company's proposed program plan. The specific commercial program services and rates have been designed for that class of customers. Please also see the Company's response to KPSC 1-30.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Direct Testimony of Mr. Rogness at page 15, lines 10-13, please state whether it is Mr. Rogness's belief that the existence of the industrial opt out means that it is unrealistic to expect any industrial customer participation in DSM/EE programs. If this is not Mr. Rogness's belief, please explain what this portion of the testimony suggests in terms of industrial customer participation.

RESPONSE

Please see the Company's response to SC 1-21 and KSPC 1-30.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

Referring to the Direct Testimony of Mr. Rogness at page 16, lines 14-9, does the "robust customer participation levels" referenced in the testimony reflect the participation levels in AEG's High Scenario customer participation level. If not, please explain what the term represents.

RESPONSE

No. The adjective robust was intended to refer to participation levels at the mid scenario level.

WITNESS: John A Rogness